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Vice President
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July 28, 2014

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The Honorable Chair and Members of the
Hawai'i Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawai'i 96813

Dear Commissioners:

Subject: Docket No. 2007-0341 – Hawaiian Electric Companies:
Submission of Integrated Demand Resource Portfolio Plan

In accordance with and as required by Order No. 32054, filed April 28, 2014, Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc. and Maui Electric Company, Ltd. hereby submit their Integrated Demand Response Portfolio Plan ("IDRPP").

Very truly yours,

Attachment

cc: Division of Consumer Advocacy

Integrated Demand Response Portfolio Plan

July 2014

The Hawaiian Electric Companies submit this document to comply with the Decision and Order issued by the Hawai'i Public Utilities Commission on April 28, 2014 in Docket No. 2007 0341, Order No. 32054.

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Abstract

Overall Strategy

The Hawaiian Electric Companies propose to implement a portfolio of demand response programs that appeals to a wide variety of residential and commercial customers, reduces the cost of electricity, and enables higher levels of renewable energy without compromising service reliability.

With the continued growth of rooftop solar photovoltaics in our systems, our customers play an increasingly important role in energy supply. With the demand response programs introduced in this Integrated Demand Response Portfolio Plan (IDRPP), we are providing our customers with additional options to both manage their energy costs and provide valuable services to the grid that will benefit all customers.

Our overall goal is to aggressively pursue all demand response programs that best serve the interests of our customers across all five island grids.

Our Intense Focus on Demand Response

The Hawaiian Electric Companies firmly believe that demand response should be an integral part of our power supply toolkit—and it will be. We will be employing our demand response portfolio on the supply side—implementing thermal energy storage and customer-sited generators to meet capacity—as well as on the demand side—to meet several essential ancillary services. And we will use the competitive marketplace to acquire cost effective demand response resources that benefit all customers.

Grid Service Requirements Met by Our Demand Response Portfolio

Transitioning to using variable renewable generation has created opportunities for demand response to contribute in meaningful ways to meet grid services needs. Demand response can contribute to capacity, several ancillary services (including regulating reserve, contingency reserve, non-spinning reserve, and non-Automatic Generation Control (AGC) ramping), and accelerated energy delivery. A primary focus of our demand response programs will be to provide ancillary services, a leading-edge initiative which represents a great opportunity on our islanded power grids.

We are proposing a portfolio of demand response programs—each meeting several Commission objectives—that fall into seven targeted categories:

1. **Residential and Small Business Direct Load Control program:** Expanding on the existing Residential Direct Load Control and Small Business Direct Load Control programs, program participants allow us to control certain equipment to better manage load demand fluctuations.
2. **Residential and Small Business Flexible program:** This program enables control of targeted devices to meet ancillary service requirements.
3. **Commercial & Industrial Direct Load Control program:** Participants in this updated program allow us to control certain equipment to shift load.
4. **Commercial & Industrial Flexible program:** This flexible program enables the use of targeted equipment to meet ancillary service requirements.
5. **Commercial & Industrial Pumping program:** This program enables control of certain water pumping facilities to better balance supply and demand.
6. **Customer Firm Generation program:** This program enables dispatching on-site customer generators to meet demand.
7. **Dynamic & Critical Peak Pricing program:** This program enables load shifting to "smooth" the daily system load profiles based on demand and price.

Marketing to Ensure Success

Our plan calls for marketing to a wide circle of commercial businesses with an expanded focus on residential customers.

The "maximum price" paid for a DR program would be the difference between the avoided cost and the program's operational cost. The "avoided cost" is the cost of an alternative resource (energy storage or a generator) providing the equivalent service. At the "maximum price," the overall rate impact to customers would be economically neutral. To create the maximum benefit and participation, we will bring our DR programs to the open market to best determine price and appeal, and drive their adoption through third-party agents selected for their expertise and experience. Whenever the market price paid for DR is less than the "maximum price," all customers benefit, and the participating DR customer receives an additional credit or payment.

We plan a company-wide implementation, transitioning from existing programs into our new DR portfolio, including establishing a centralized DR staff who will focus solely on administering the programs. We also look forward to working with others companies offering DR expertise and technologies to facilitate the pace and effectiveness of the DR programs. The implementation timeline calls for immediate action across O'ahu, Maui, and Hawai'i Island, with planned future implementations on Lana'i and Moloka'i. As the implementation unfolds, we will measure performance and adjust as needed to maximize the impact of our programs.

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Executive Summary

The Hawaiian Electric Companies propose to implement a portfolio of demand response programs that appeals to a wide variety of residential and commercial customers, providing more options to reduce the cost of electricity, and enabling higher levels of renewable energy without compromising service reliability.

ROLE OF DEMAND RESPONSE IN HAWAI'I'S ENERGY FUTURE

Our Integrated Demand Response Portfolio Plan (IDRPP) recognizes and formalizes our customers' changing role in the power grid. In the past, controllable generation supply was dispatched to meet the fluctuating load demand of the power system. Because our customers' energy needs are increasingly supplied by variable renewable energy resources, an important solution for balancing supply with demand is to enable customer demand to be more dispatchable.

With the continued growth of rooftop solar photovoltaics in our systems, our customers play an increasingly important role in energy supply. With the new and expanded demand response programs introduced in this IDRPP, we are pleased to offer our customers additional opportunities to both manage their energy costs, and provide valuable services to the grid that benefit all customers.

OVERALL STRATEGY

This IDRPP presents a number of demand response (DR) programs that benefit all customers. These benefits include reduced energy supply costs, reduced energy curtailment, and increased system reliability. Customers who participate in demand response programs also benefit from incentive payments or credits on their energy bills.

Overall, our DR portfolio provides a "higher level of operational flexibility so as to support, among other things, integration of additional renewable resources, such as solar and wind".[1] We will use our DR portfolio as an essential tool in our system operation tool kit to address the changing profile of energy demand created by the growth in solar energy resources.

Our IDRPP calls for immediate action across O'ahu, Maui, and Hawai'i Island with plans to extend the DR programs as they mature to Lana'i and Moloka'i. We propose updating and refreshing the existing DR programs to more clearly and cost-effectively fulfill grid service requirements. We propose to launch the full portfolio of DR programs in 2015, and to deliver grid services from these new programs by early 2016. We also plan to launch an expedited Customer Firm Generation program for Maui to deliver capacity in 2015.

Mission Statement

We have adopted the following mission statement to guide us in our continued development of innovative and useful DR programs:

"The Hawaiian Electric Companies will aggressively pursue all demand response programs that best serve the interests of our customers across all five island grids."

[1] Docket No. 2007-0341, Order No. 32054, *Policy Statement and Order Regarding Demand Response Programs*, at 4.

Guiding Principles for Implementing Our Demand Response Portfolio

We intend to adhere to these guiding principles for designing, implementing and managing our demand response portfolio:

Meet the Need: Ensure that the grid services requirements (capacity and ancillary services) are met to the maximum extent that is practical and cost effective using demand response.

Seek Diversity: Pursue demand response programs that can be readily implemented, comprise a diverse set of features, employ customer equipment, meet grid service requirements, and can be adroitly administered to maintain system reliability.

Defer to the Market: Determine the optimal compensation that maximizes participation in our demand response portfolio without compromising cost effectiveness for customers.

Enlist Expert Assistance: Take advantage of third-party expertise—including that of Hawai'i Energy[2]—to recruit participants, and to launch and implement demand response programs.

Continue Evolving: Aggressively research new ways for customers to participate, evaluate their applicability in our unique environment in Hawai'i, identify and quantify their benefits, and quickly implement them.

HOW WE DEVELOPED OUR DEMAND RESPONSE PROGRAMS

To develop our Integrated Demand Response Portfolio Plan, we adhered to a foundational definition of demand response, accounted for Hawai'i's unique operating environment, and relied on a methodical process.

Uniqueness of Hawai'i's Island Grids

Demand response programs implemented elsewhere may need to be modified to meet our unique island needs. Here are several reasons why this is true:

- Unparalleled amounts of variable renewable generation, due mostly to growing amounts of distributed generation.

[2] The Hawai'i Public Utilities Commission (PUC) has contracted with Hawai'i Energy to administer Hawai'i's energy efficiency programs.

- Value of demand response compared to alternatives (for example, centralized generation or energy storage) to cost-effectively provide ancillary services needed for secure system operation.
- Independent island grids that are not interconnected and the resulting inability to rely on short-term assistance from other utilities or a regional power pool.
- No significant seasonal demand fluctuations and relatively consistent daily load demand profile.
- Larger generating unit sizes relative to system demand, requiring significantly different system security and reliability criteria.[3]
- Significant load shedding is utilized to prevent system collapse (i.e., island-wide blackouts) during major disturbances.

We considered all of these factors in designing a demand response portfolio that is appropriate for Hawai'i.

Method for Developing the IDRPP

We followed three key steps in developing our IDRPP. We:

1. Established the grid service requirements for O'ahu, Maui, and Hawai'i Island, and used them to identify the services and specifications required for our DR portfolio.
2. Examined sector-specific end-uses and overall load potential to identify loads that could be interrupted to meet grid service requirements and were acceptable to the customers providing those loads.
3. Designed DR programs in a common format to satisfy both grid service requirements and the availability of customer-specific end-uses.

As a result, we modified some existing DR programs and designed new ones that meet our specific grid service requirements, and which are complementary within the overall portfolio. We have also designed a procurement process that ensures any DR program offers real benefit and value to customers, offers benefits greater than the estimated program costs, and benefits all customers including non-participants.

[3] The maximum size of individual generating units is currently being evaluated by the Companies as part of their development of Power Supply Improvement Plans (PSIP) in the contexts of system security and overall cost for system operation. Therefore, this factor that contributes to the uniqueness of the Hawaiian power systems is subject to change.

THE DEMAND RESPONSE PROGRAMS WE DEVELOPED

The Hawaiian Electric Companies have reviewed and overhauled our existing demand response programs. We have also designed a number of new and beneficial DR programs that have been consolidated into a single integrated DR portfolio.

We plan to increase our collaboration with Hawai'i Energy to maximize the availability, timeliness, and use of cost-effective DR resources throughout Hawai'i. We also plan to continue to build on our partnership with Energy Excelerator, a clean energy startup accelerator program to incorporate the use of emerging technologies to continuously enhance our DR portfolio.

Grid Service Requirements Met by Demand Response

Firm generation that has traditionally been used to provide ancillary services is increasingly being replaced by variable renewable generation that has markedly less capability to provide these services. This creates opportunities for demand response to contribute in meaningful ways by providing ancillary services.

As summarized in Table ES 1, demand response can contribute to grid service requirements, including capacity, several ancillary services (including regulating reserve, contingency reserve, non-spinning reserve, and non-Automatic Generation Control (AGC) ramping), and accelerated energy delivery.

Grid Service Requirements	Response Speed* (Mainland)	Response Speed* (Hawaii)	Response Duration	Potential for DR?
Capacity				
Capacity Used to meet demand plus reserve margin; supplied by on-line and off-line resources, including interruptible load	Minutes	scheduled in advance by system operator	If called, must be available for at least 3 hours	✔
Ancillary Services				
Contingency Reserve** Reserves to replace the sudden loss of the single largest on-line generator, supplied from online generation, storage or DR	Seconds to <10 min	Within 7 cycles of contingency event	Up to 2 hours	✔
Regulating Reserve Maintain system frequency, supplied from on-line capacity that is not loaded	<1 min	2 seconds, controllable within a resolution of 0.1 MW	Up to 30 min	✔
Non-Spinning Reserve Used to restore regulating reserves and contingency reserves; supplied by off-line fast start resources or DR	10-30 min	<30 min	2 hours	✔
Non-AGC Ramping Resources that can be available prior to quick start generation and can add to system ramping capability	N/A	<2 min	Up to 2 hours	
Black Start Capability The ability of a generating unit to start without system support	N/A	<10 min	Duration of system restoration time	✖
Inertial Response Local (i.e. at a generator) response to a change in frequency; supplied by rotational mass of generators, or power electronics of inverter-based resources	N/A	2-3 seconds	2-3 seconds	✖
Other				
Accelerated Energy Delivery*** Shifting the demand for energy from high demand evening peak periods to lower demand midday periods, or higher demand morning periods to lower demand overnight periods	N/A	N/A	N/A	✔

* Response speed refers to the time needed to "dispatch" a resource, automatically or manually, once it is known it is needed
** Contingency reserves that cannot meet the 7 cycle operation requirement are not fast enough to serve as primary protection resources (e.g. spinning reserves), but may be able to meet the contingency reserve requirements consistent with the "locker block" of secondary resources.
*** Accelerated Energy Delivery is not an ancillary service product of the Hawaii system, but will help meet the need to reduce peak loads and especially to increase overnight and midday demand

Table ES 1. Demand Response Role in Providing Ancillary Services

Ultimately, we will consider customer and end-use resources that can effectively and efficiently be targeted for DR program participation. Examples include Variable Frequency Drives (VFDs) for water pumps and other motor loads, Light-emitting Diode (LED) lighting, refrigeration, ventilation, standby generators, and Grid Interactive Water Heaters (GIWHs).

Portfolio Approach

Each DR program in our proposed portfolio accomplishes a range of objectives that collectively address our grid service requirements. The programs fall into two groups:

- **Direct Load Control Programs**: where we can remotely shut down or cycle customers' electrical equipment (such as air conditioners, water heaters, and lighting).
- **Flexible Programs**: where we can remotely adjust (directly or through a third-party DR administrator) the operation of customers equipment, up or down, to meet grid ancillary services.

Evolution of Our Demand Response Programs

In developing our IDRPP, we determined that our plan needs to take better advantage of some existing direct load control programs such as Residential Direct Load Control (RDLC), while devising new programs to more effectively provide customer options that contribute to ancillary services, enable peak loads to be shifted to lower demand periods, reduce curtailment, incorporate greater amounts of renewable energy, and create better customer incentives for increased participation (depicted in Figure ES 1).

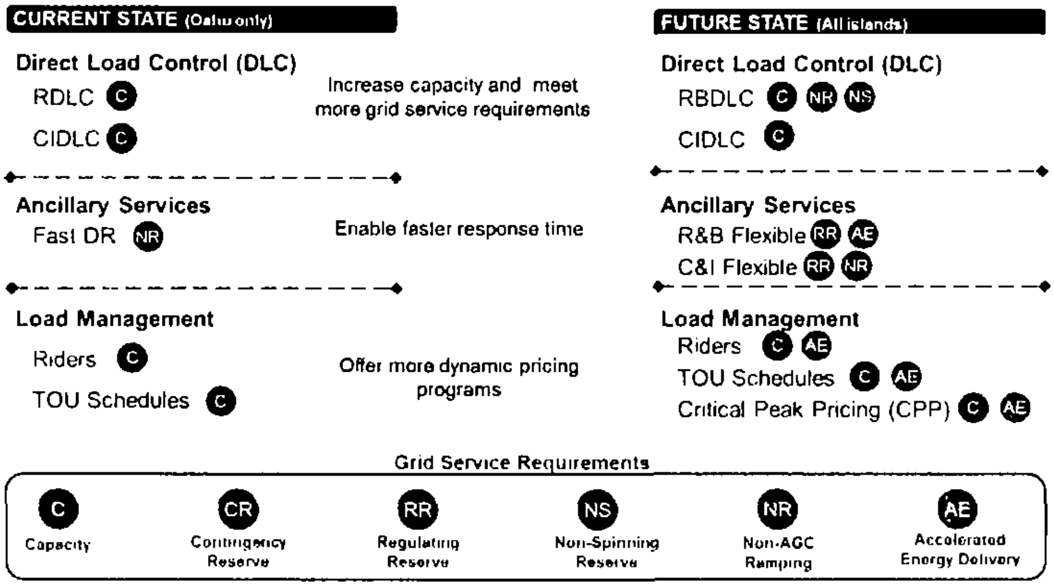

Figure ES 1. Current and Future Demand Response Expanded Benefits

The Demand Response Programs

We are proposing demand response programs that fall into seven categories:

1. Residential and Small Business Direct Load Control (RBDLC)
2. Residential and Small Business Flexible
3. Commercial & Industrial Direct Load Control (CIDLC)
4. Commercial & Industrial Flexible
5. Commercial & Industrial Pumping
6. Customer Firm Generation
7. Dynamic and Critical Peak Pricing

DR Program Descriptions

New, Residential and Small Business Direct Load Control Program (RBDLC)

This new RBDLC program continues and expands upon the existing RDLC and Small Business Direct Load Control (SBDLC) programs. RBDLC enables new and existing single-family, multi-family, and master metered residential customers, in addition to small businesses, to participate in an interruptible load program for electric water heaters, air conditioning, and other specific end uses.

New, Residential and Small Business Flexible Program

This new program enables residential and small business customers with targeted devices (such as controllable grid-interactive water heaters) to meet ancillary service requirements by providing adjustable load control and thermal energy storage features over various timeframes.

Updated, Commercial & Industrial Direct Load Control Program (CIDLC)

The updated CIDLC program allows commercial and industrial customers to help shift load, usually during peak periods, by allowing their central air conditioning, electric water heaters, and other applicable appliances to be remotely cycled or disconnected.

New, Commercial & Industrial Flexible Program

This new program enables commercial and industrial customers with targeted devices (such as air conditioning, ventilation, refrigeration, water heating, and lighting) to meet ancillary service requirements by providing adjustable load control and/or thermal energy storage features over differing timeframes.

New, Commercial & Industrial Pumping Program Overview

The Commercial & Industrial Pumping program enables county and privately owned water facilities with pumping loads and water storage capabilities to be dynamically controlled. This will be accomplished by using variable frequency drives and emergency standby generation to adjust power demand and supply at the water facilities, and better balance supply and demand of power system loads.

New, Customer Firm Generation Program

Commercial and industrial customers who participate in this program allow system operators to dispatch their on-site standby generators to help meet power system load demand. Monitoring equipment on the standby generators tracks the usage of program participation, testing, and assures environmental permit compliance.

Updated, Dynamic and Critical Peak Pricing Program

The Dynamic and Critical Peak Pricing programs are designed to shift loads from peak-demand to lower-demand periods to effectively "smooth" the system daily load demand profile. These pricing programs would adjust specific prices for electricity power from the grid throughout the day, sending price signals to customers to encourage shifting of their load demands.

Using Demand Response as a Grid Resource

Due to system security considerations on our island-based power grids, the Companies' system operators would be able to employ demand response programs for up to approximately 15% of the electric system load to regulate capacity and serve ancillary services throughout the day and night. The DR program subscriptions, in total, are expected to substantially exceed 15% of the estimated peak load for the system—an adoption goal of our DR portfolio. System operators should be able to serve up to 15–20% of system load at any time using DR to balance the power system. It's necessary to serve the remaining 80–85% of system load by other resources to ensure the system can recover from a major disturbance.

DR Program Objectives and Potential Load Resources

Demand response programs can meet grid services, capacity and ancillary services, in several ways. The objectives for each DR program and the associated potential load resources for each program are summarized in Table ES 2.

DR Program	Grid Service	Potential Load Resources
Residential and Small Business Direct Load Control	Capacity	Water heaters Central air conditioning
	Non-AGC Ramping	Water heaters Central air conditioning
	Non-Spinning Reserve	Water heaters Central air conditioning
Residential and Small Business Flexible	Regulating Reserve	Grid interactive water heating Central air conditioning
	Accelerated Energy Delivery	Grid interactive water heating
Commercial & Industrial Direct Load Control	Capacity	Commercial & industrial curtailable Water heaters Central air conditioning
Commercial & Industrial Flexible	Regulating Reserve	Central air conditioning Refrigeration Ventilation Grid interactive water heating
	Non-AGC Ramping	Central air conditioning Refrigeration Ventilation Lighting
Commercial & Industrial Pumping	Regulating Reserve	Commercial/muni water & wastewater pumping
	Non-AGC Ramping	Commercial/muni water & wastewater pumping
Customer Firm Generation	Capacity	Customer-sited stand-by generators
Dynamic and Critical Peak Pricing	Capacity	Unspecified customer load
	Accelerated Energy Delivery	Unspecified customer load

Table ES 2. Demand Response Programs and Resources to Meet Grid Services

Actual implementation of the DR programs will further confirm how these programs and their associated resources can best contribute to grid services.

Overview of the DR Programs

The brief overview of each DR program (Table ES 3) describes how the performance of each program will be measured, their cost, and their availability. Based on the grid service requirements to be satisfied, response speed and duration requirements will vary by program and load resource.

DR Program	Performance Measurement	Cost per Event	Availability
Residential and Small Business Direct Load Control	Difference between pre-event and post-event load	None	Always available, no notification, no limits
Residential and Small Business Flexible	Difference between pre-event and post-event load	None	Continuous
Commercial & Industrial Direct Load Control	Difference between pre-event and post-event load	$0.50 per kWh	Up to 300 hours annually
Commercial & Industrial Flexible	Difference between pre-event and post-event load	None	Continuous
Commercial & Industrial Pumping	Difference between pre-event and post-event load	None	Continuous
Customer Firm Generation	Amount of self-supply and/or exported power to the grid provided during the event	$0.50 per kWh	Up to 100 hours annually

Table ES 3. Overview of the DR Programs

PROJECTED RESOURCE POTENTIAL BY DR PROGRAM

Load Resources Meeting Grid Services

We have assessed the types of resources likely to best meet specific grid services (see Table ES 4). We believe, however, that the market will best determine the optimal resource mix for meeting each grid service. To confirm these optimal uses, we will clearly state the specifications for meeting each grid service (for example, the required response time and response duration), and test the market to determine availability and costs.

Resources	Capacity	Regulating Reserve	Contingency Reserve	Non-AGC Ramping	Non-Spinning Reserve	Accelerated Energy Delivery (Intraday)
Water Heater and A/C	✓	✓	✓	✓	✓	
C&I Curtailable	✓					
Ventilation		✓		✓		
Refrigeration		✓		✓		✓
Lighting				✓		
GIWH				✓		
Water Pumping		✓		✓		✓
Customer Generation	✓					✓
Electric Vehicles*	✓					✓

* Electric vehicles have not been included in current program projections, but will be leveraged for DR as the market matures.

Table ES 4. Target Resources for Meeting Grid Services

Projected DR Potential

The estimated megawatt (MW) potential associated with each program and grid service is summarized in Table ES 5. Without exception the potential is expected to initially increase over time. These projections then plateau and begin to decline in the 2020 time frame due primarily to the effectiveness of Hawai'i Energy's energy efficiency programs.

We are committed to aggressively pursue demand response solutions and continually reevaluate their potential based on changing circumstances and emerging technologies. We expect that emerging technological advances, market conditions, and ongoing recruitment will keep DR participation levels steady beyond 2020.

Our DR portfolio is based on our current understanding of the limits of the technology for implementation. Accordingly, demand response under-frequency resources currently are not considered to respond fast enough to provide contingency reserve; and thus the entries of zero for contingency reserve in Table ES 5. Nonetheless, we are pursuing DR resources with this valuable capability, and would utilize DR resources for this purpose should the market be able to provide them in the future.

DR Program	*O'ahu Island Grid*				*Maui Island Grid*				*Hawai'i Island Grid*			
Grid Service	*2014*	*2019*	*2024*	*2034*	*2014*	*2019*	*2024*	*2034*	*2014*	*2019*	*2024*	*2034*
RBDLC												
Capacity	10.0	30.4	33.3	33.3	0.0	5.7	7.1	7.1	0.0	4.9	6.0	6.0
Contingency Reserve	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-AGC Ramping	10.0	30.4	33.3	33.3	0.0	5.7	7.1	7.1	0.0	4.9	6.0	6.0
Non-Spinning Reserve	10.0	30.4	33.3	33.3	0.0	5.7	7.1	7.1	0.0	4.9	6.0	6.0
R&B Flexible												
Regulating Reserve	0.0	3.3	5.1	5.1	0.0	0.7	1.1	1.1	0.0	0.9	1.4	1.4
Accelerated Energy Delivery	0.0	1.7	2.7	2.7	0.0	0.4	0.6	0.6	0.0	0.5	0.7	0.7
C&I DLC												
Capacity	10.0	23.8	25.4	25.4	0.2	2.5	3.0	3.0	0.0	1.8	2.2	2.2
Contingency Reserve	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&I Flexible												
Regulating Reserve	0.0	2.6	4.1	4.1	0.0	0.4	0.6	0.6	0.0	0.3	0.4	0.4
Non-AGC Ramping	0.0	9.0	14.1	14.1	0.0	1.3	2.1	2.1	0.0	0.9	1.4	1.4

C&I Pumping												
Regulating Reserve	0.0	1.2	1.9	1.9	0.0	0.2	0.3	0.3	0.0	0.1	0.2	0.2
Customer Firm Generation												
Capacity	0.0	5.0	5.0	5.0	0.0	3.0	3.0	3.0	0.0	3.0	3.0	3.0
Total Load Under Control*	26.0	70.2	82.4	82.4	0.2	13.1	16.1	16.1	0.0	11.1	13.6	13.6

** Total number reflects the sum of the potential obtained from each load resource used to calculate these projections (which is not equal to the sum of the potentials identified under each grid service requirement in the table because of program overlap and the ability of some end use resources to meet multiple grid service requirements).*

Table ES 5. Potential MW Benefits for Demand Response Programs

Mapping Planned Demand Response Programs to Objectives of the Commission's Order

Each DR program's design has been driven by and crosschecked against the guidelines and directives issued by the Commission (Table ES 6) in Docket No. 2007-0341, Order No. 32054. Every DR program meets more than one Commission objective; and every Commission objective is met by at least three programs.

The DR programs will compensate customers for their participation and the value they add to the system, and provide them with opportunities for reducing their total electricity bills. The programs will also provide the Companies with a range of options for meeting a portion of the grid services requirements, while reducing reliance on fossil fuel and increasing the system's ability to take the greatest advantage of renewable energy resources.

Mapping Programs to Order Objectives	Residential & Small Business		Commercial & Industrial			Muni/C&I	Pricing
The commission established the following as the stated objectives for the current and future DR programs	DLC	Flexible	DLC	Flexible	Customer Generation	Water Companies*	Dynamic, CPP
1. DR programs should provide quantifiable benefits to ratepayers	H	H	H	H	H	H	H
2a. A reduction in total kWh consumed or a change in how kWhs are consumed that is beneficial to overall system operations	H	H	H	H		H	H
2b. A reduction in peak loads, and the deferral of new generation capacity	H		H		H	H	H
2c. Assistance in meeting PV and wind variability	M	H		H		H	
2d. A shift of a portion of system load to off-peak times (which may be mid-day in the near future for systems with high PV penetration) to among other things increase consumption of minimum load generation and to reduce curtailments of renewable generation		H		M		H	H
2e. Assistance in assuring the reliability of the system through among other things programs that permit fast response of short duration to meet contingency conditions prior to utility emergency diesel generations coming on line	M	H	M	H		H	
2f. A non fossil fuel source of ancillary services, such as frequency management, up and down regulation, and dispatch able energy	M	H		H		H	
2g. Customer benefits such as greater control over energy use and opportunities to lower electricity bills**	H	H	H	H	H	H	H
2h A potential means for addressing greenhouse gas emissions standards established by the state of Hawaii and federal government.	H	M	H	M	H	H	H

H = Highly Satisfies M = Moderately Satisfies

* Water Companies category includes pumping as load resources and on-site emergency generators, both considered as potential DR options.

** All program participants (i.e. DR providers) will be paid for participating and will thus be able to lower their electricity bills; only pricing program participants would be viewed as having more control over their energy use.

Table ES 6. Mapping DR Programs to the Objectives (Order, p. 82-83)

PRICING THE DEMAND RESPONSE PLANS

The value of a DR program is directly associated with the costs it otherwise avoids if other resources provide the equivalent service. The compensation paid (or credited to his/her energy bill) to a customer participating in a DR program, is a direct benefit for that customer. All customers benefit from the overall value of the DR program.

Cost of DR Programs

Avoided cost for a grid service could be based on several factors, including installed capacity costs, fuel costs, and cost of alternatives, each of which depends on the current state of the system. Potential avoided cost calculations include:

Capacity: The cost of new capacity.

Regulating Reserve: The cost of a frequency support energy storage device, or the savings from reduced regulating reserve requirements.

Contingency Reserve: The fuel cost savings resulting from a reduction in the contingency reserve requirement (for O'ahu) or to offset under-frequency load shedding savings (for Maui and Hawai'i Island).

Non-AGC Ramping: The installed cost of new quick start generation or the fuel cost and maintenance savings resulting from not having to start units to compensate for wind volatility.

Non-Spinning Reserve: The cost of maintaining existing resources that currently meet non-spinning reserves.

Advanced Energy Delivery: The installed capital cost of a load shifting energy storage device.

When a resource or program meets more than one grid service requirements, but not simultaneously, the higher avoided cost will be used.

Compensation for DR Programs

The "maximum price" paid for a DR program would be the difference between the avoided cost and the program's operational cost. The "avoided cost" is the cost of an alternative resource (energy storage or a generator) providing the equivalent service. At the "maximum price," the overall rate impact to customers would be economically neutral. To create the maximum benefit and participation, we will bring our DR programs to the open market to best determine price and appeal, and drive their adoption through third-party agents selected for their expertise and experience. Whenever the market prices paid for DR is less than the "maximum price," all customers benefit, and the participating DR customer receives an additional credit or payment.

IMPLEMENTING DEMAND RESPONSE PROGRAMS TO BE SUCCESSFUL

Successful DR programs save more than they cost, because the DR resources are acquired at a lower cost than the costs they avoid. They have inherent appeal that attracts customer participation, consistently meets the needs of the electric grid, and maintains a high level of system reliability.

DR Portfolio Delivery Roadmap

We have developed an implementation plan to manage the delivery of our DR portfolio that includes standards and approaches on how to measure the performance and overall benefits that can be achieved from our DR portfolio.

DR Portfolio Implementation Timeline

The implementation timeline calls for immediate action across all three islands (Figure ES 2), with planned future implementations on Lana'i and Moloka'i. The full portfolio of DR programs would be launched in 2015, with the actual delivery of grid services expected to occur by January 2016.

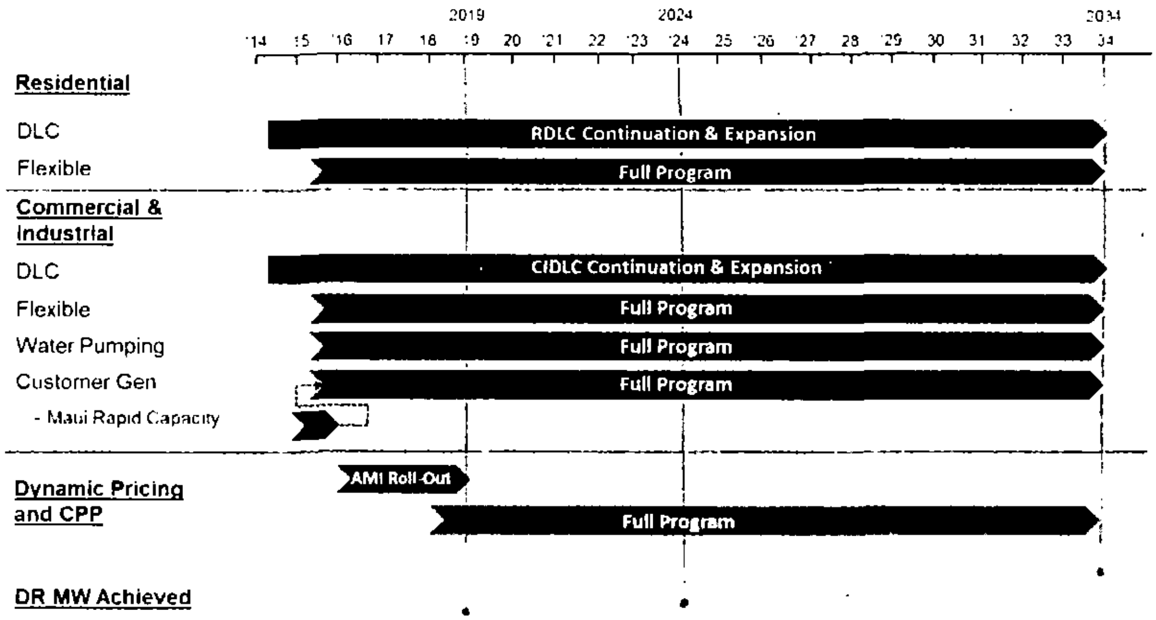

Figure ES 2. Timeline for the DR Portfolio Action Plan

Using Third-Party Agents and Aggregators

To implement our DR programs as quickly as possible, at the outset we anticipate contracting with third-party agents and aggregators to act as service providers on our behalf. They are the end use and control system experts whose expertise can be leveraged to expedite aggressive implementation of our plan. This approach seeks to enable our customers to benefit quickly and effectively from a robust and diversified DR portfolio that can provide the required grid services.

We will evaluate potential service providers based on their abilities across a range of criteria including cost of service, experience, ability to perform at a high level, knowledge of specific project needs, technology offerings, and the terms and conditions of their engagement.

Technical Considerations

We will apply several technical design principles to ensure that the DR architecture and solutions can be implemented across a wide scale, and are lasting and cost effective. These principles include:

- Incorporating the latest cyber security techniques into the architecture.
- Implementing scalable solutions that allow for the management of hundreds of thousands of endpoint devices and customer loads.
- Taking advantage of open and best practices to establish processes, patterns, and templates that can be repeated for all DR programs.
- Establishing interoperability to maintain the greatest amount of flexibility and independence for implementing DR solutions.

We will be installing and implementing a number of key technical requirements.

- A Demand Response Management System (DRMS) to better manage all aspects of our DR portfolio.
- Communication networks and protocols to better manage the DR programs and remotely manipulate customer equipment.
- Control devices for the desired end uses (such as multiple load control switches and programmable communicating thermostats).
- Engineering and operational consulting assistance to assess customer DR sites.

Company-Wide Implementation

Implementing our DR portfolio across all three operating utilities will be a major undertaking and a high priority. The Companies believe that it is important to expeditiously move forward on the implementation, and would welcome guidance from the Commission on how best to proceed following the filing of this IDRPP. We plan to immediately launch our efforts on the DR portfolio. We are proposing a step-by-step process.

1. Expedite the procurement process for those DR responses necessary to provide immediate capacity needs on Maui.
2. Establish a new DR regulatory framework, mainly to develop a new approach to recovering DR-related costs through base rates and a demand response cost recovery clause.
3. Adjust the existing DR program portfolio for 2015 by enhancing the current RDLC program, refocusing the CIDLC program, transitioning the Fast DR

programs to the proposed commercial DR programs, and adjusting rider and TOU programs.

4. Establish new DR services, standards, and operational protocols, such as determining the quantities of grid services to be procured by O'ahu, Maui, and Hawai'i Island; creating business processes and pro forma contracts for working with third-party vendors; and creating operational protocols and communications requirements.

5. Design a market-based procurement process to determine the market price for DR programs so that we can attain the best value for our customers.

6. Procure DR resources from pre-qualified customers and third-party DR providers through a reverse auction process to achieve the best market price for each service.

7. Grow the RBDLC program on O'ahu to expand its participation (especially by residential customers) and launch parallel programs on Maui and Hawai'i Island, and to evaluate the efficiency and effectiveness of transferring the program's operation to a third-party vendor.

8. Establish a centralized DR organization to focus on planning, designing, engineering, administering, and reporting on the DR portfolio plan across all three operating utilities to ensure its success and shepherd its growth.

9. Establish variable pricing programs based on the AMI component of our smart grid implementation.

Integration with Other Resource Plans

We are confidently moving forward on a number of efforts that will shape the future of electric generation, electric delivery, and customer service for years to come. These efforts include Power Supply Improvement Plans (PSIP) for all three operating utilities, a Distributed Generation Interconnection Plan (DGIP), this IDRPP and our smart grid plan. These plans, and the strategic direction and implementation actions they separately establish, are highly interrelated. The PSIP analyses, currently in progress, will evaluate the cost-effectiveness of our DR portfolio.

The integrated DR portfolio, while just one part of the overall plan, will provide more options for customer benefits, better meet grid service requirements, and will be flexible enough to adjust to the demands of our evolving power system.

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1. Background and Objectives

Hawaiian Electric, Maui Electric, and Hawai'i Electric Light (the "Companies") share the Commission's perspective for an Integrated Demand Response Portfolio Plan (IDRPP) that would lead to the materialization of demand response (DR) programs as dependable, critical resources for operation of the island grids throughout Hawai'i. The Companies concur with the Commission's guidance, and have endeavored to produce an IDRPP that capitalizes on available resources (current and future) and that will result in a comprehensive portfolio of DR programs. Moreover, the IDRPP provides an executable implementation plan for timely realization of the diversified DR programs on each island grid.

In developing this IDRPP, the Companies have consciously been aggressive. In parallel, the Companies are currently developing Power Supply Improvement Plans (PSIP) for each operating company, and the portfolio of DR programs defined herein are being included to provide critical grid services within these plans.

UNDERSTANDING OF THE COMMISSION'S GUIDANCE

The Companies have carefully reviewed the Commission's Order No. 32054 (the Order) that was issued April 28, 2014. This subsection summarizes the Companies' understanding of the guidance provided by the Commission in the Order.

Understanding of the Order

At a high level, the Order directs the Companies to complete an overhaul of their existing DR programs with the goal of consolidating those programs into a single integrated DR portfolio, establishing overall objectives and goals for the integrated portfolio (as well as individual programs within the portfolio), and developing and utilizing appropriate standards to measure the performance of (and the overall benefits achieved by) the integrated DR portfolio and each DR program within the portfolio.

The Companies also understand the more detailed directives issued throughout the Order, including those that request comprehensive coverage and inclusion of the following:

- Consolidation of DR Programs
- Comprehensive Evaluation of the DR Opportunity, including information on the following:
  - Detailed estimates of DR potential
  - The role of individual DR programs in achieving the overall objectives of the integrated DR portfolio
  - The role of DR in reducing curtailment of renewables, eliminating the need for baseload generation, and achieving renewable portfolio standards[4]
  - Technology requirements and limitations
  - Potential DR limitations
  - The role of customer-provided DR
  - The role of third-party providers of DR
  - The impact of DR on greenhouse gas emissions
- Close coordination with Hawaii Energy to find synergies between energy efficiency and DR
- Composition and cost effectiveness of the integrated DR portfolio[5]
- Portfolio reporting requirements
- Discussion of program budgets
- Coordination with water companies

The Companies understand and appreciate the Commission's commentary and guidance, and agree to develop and implement a comprehensive integrated DR portfolio. The Companies agree to the directions provided in the Order, and have attempted through the balance of this plan to provide an integrated DR portfolio that is responsive to the Order and that creates an executable roadmap that is in the best interest of the Companies' customers on all islands in which they operate.

[4] The analyses being performed in the development of the Companies' Power Supply Improvement Plans will address, in parts, the roles that DR can play in reducing curtailment of renewables, eliminating the need for baseload generation, and achieving renewable portfolio standards.

[5] Ibid.

Insight into the Current State

The Order includes the following guidance to the Companies:

- Clearly define the unified common objectives and goals of the overall IDRRP to which each individual DR program contributes;
- Communicate the overall structure under which DR programs are coordinated, consistent with objectives and goals of the IDRRP;
- Establish methodologies to demonstrate that DR programs taken together provide quantifiable net benefits to ratepayers;[6]
- Design new DR programs and where appropriate, modify existing DR programs that provide value now and in the future as the power system is transformed to accommodate higher levels of renewable resources;
- Develop DR programs that provide flexible responses (in addition to peak reduction), including the ability of DR to provide operating reserves. In doing so, take advantage of technological advances.

The Commission also finds that "a more aggressive approach to demand response is appropriate for Hawai'i Electric Light and Maui Electric where there are significant amounts of variable renewable energy resources already installed and there is the need to reduce the curtailment of renewable energy resources." The Companies agree with the Commission's conclusions in this regard.

The Companies understand and accept the Commission's guidance. The Companies agree that a structured, aggressive, and integrated approach is required to take maximum advantage of the roles DR can play on all island grids.

IDRPP OBJECTIVES AND MISSION STATEMENT

The Companies' objectives are to design, develop, and implement a progressive portfolio of DR programs that: enable higher levels of renewable energy resources, reduce the potential for curtailment of generation from lower-cost renewable energy resources, and assure secure, reliable system operation in a cost-effective manner. To the extent that DR programs are more cost-effective than interchangeable alternatives (for example, firm generation or energy storage), DR would be chosen and implemented to lower the cost of electric power for customers.

[6] Ibid.

Although considerable efforts have been devoted to develop an IDRPP that is executable and has long standing, we are cognizant that circumstances can and will evolve. Accordingly, the Companies are prepared to revise the update the IDRPP as appropriate in the future.

The current IDRPP has been developed with a focus on meeting the grid service requirements[7] of the O'ahu, Hawai'i, and Maui electricity grids. Ultimately, the Companies plan to take full advantage of DR on all five island grids in the Companies' service territories, but this IDRPP does not include plans to immediately launch DR programs on Lanai and Molokai. Lana'i and Moloka'i feature significant uncertainty in the near term with respect to demand and supply of electric power. But both islands are expected to benefit from adding DR. Maui Electric will expand the current plan in 2015 to include Lana'i and Moloka'i, where strategy and implementation steps will be informed by early efforts on O'ahu, Hawai'i, and Maui.

DR resources targeted, quantities contracted, and per unit prices paid will differ by island, but the ultimate objective is the same. Under the proposed IDRPP, all islands will add programs designed to cost effectively provide capacity deferral (where applicable) and required ancillary services.

The Company has developed and will implement its demand response strategy according to the following mission statement:

Demand Response Mission Statement

"The Hawaiian Electric Companies will aggressively pursue all demand response programs that best serve the interests of our customers across all five island grids."

Accordingly, the Companies will adhere to the following guiding principles for designing, implementing, and managing the Integrated Demand Response Portfolio:

[7] In this report, the term "grid service requirements" refers collectively to the capacity and ancillary services required for reliable operation of the electricity grid.

Meet the Need: Ensure that the grid services requirements (capacity and ancillary services) are met to the maximum extent that is practical and cost effective using Demand Response.

Seek Diversity: Pursue demand response programs that can be readily implemented, comprise a diverse set of features, employ customer equipment, meet grid service requirements, and can be adroitly administered to maintain system reliability.

Defer to the Market: Determine the optimal compensation that maximizes participation in our demand response portfolio without compromising cost effectiveness for customers.

Enlist Expert Assistance: Take advantage of third-party expertise—including that of Hawai'i Energy[8]—to recruit participants, and to launch and implement demand response programs.

Continue Evolving: Aggressively research new ways for customers to participate, evaluate their applicability in our unique environment in Hawai'i, identify and quantify their benefits, and quickly implement them.

IDRPP OVERVIEW AND METHODOLOGY

The Companies proceeded in three steps to develop this IDRPP:

1. Established the grid service requirements of all islands and used them as a framework to identify the services and specifications required of the DR programs of the IDRPP.
2. Evaluated load resources and overall load DR potential to identify loads that are controllable and that can be utilized to meet the grid service requirements. In doing so it was important to consider the terms and conditions that would be acceptable and preferred by customers participating in the DR programs.
3. Designed DR programs and proposed modifications to existing programs to best meet grid service requirements, to take advantage of the DR potential that exists, and to consider customer demographics and preferences.

[8] The Hawai'i Public Utilities Commission (PUC) has contracted with Hawai'i Energy to administer Hawai'i's energy efficiency programs.

An overview of the IDRPP process is provided in Figure 1. This process, and each component in the process, will be discussed in greater detail throughout this report. Briefly however, the components of this process are:

1. Define the specifications a DR program must be capable of meeting, such as response time and duration, to provide a specific grid service.
2. Publish the specifications to the market, including individual customers and third-party demand-side aggregators.
3. Determine the "maximum price" that could be paid for a DR resource, based on the cost of alternatives that would be required to meet the grid service requirement in the absence of the DR resource (e.g., flexible generation and/or energy storage).
4. Implement a market process (e.g., an auction) to secure DR resources. Such a process would ensure, by rule, that DR resources are procured at a price that can only be at or below the cost of equivalent supply alternatives. That clearing price would generally be set under three-year contracts with the winning bidders.
5. Contact successful bidders and ensure availability of the DR resource consistent with the Companies' technical and communications specifications.
6. Make the DR resource available to the system operator, who will utilize tools such as a Demand Response Management System (DRMS) to manually or automatically deploy the amount of required DR resources in conjunction with supply side resources (i.e. generating units and energy storage) to balance system supply and demand.

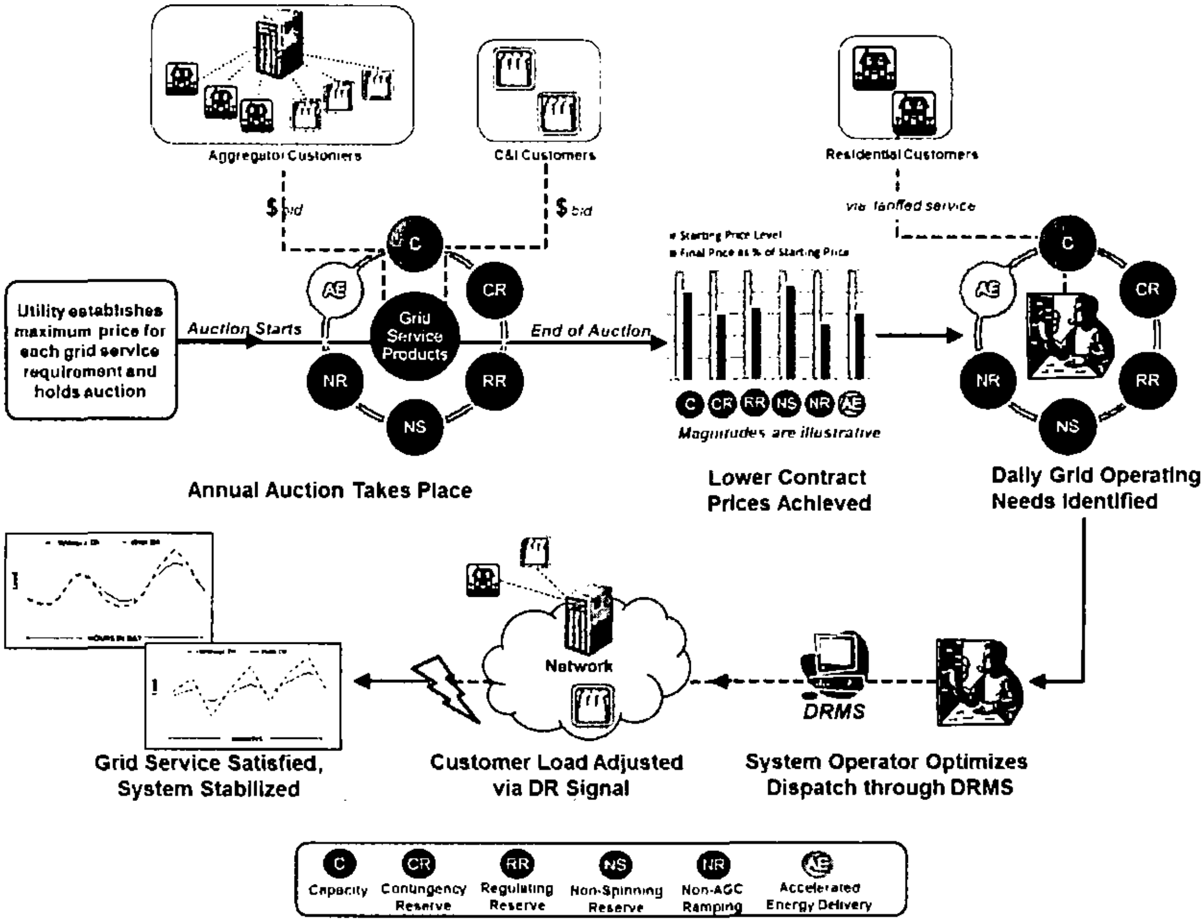

Figure 1. Overview of the IDRPP process to satisfy a grid service requirement

Defining Grid Service Requirements

Electric grids in Hawai'i are characterized by the fact that they operate as electrical (and physical) islands, without interconnections to other systems. This characteristic requires grid services in greater quantities (in proportion to peak load), and it requires much faster response times and longer durations for grid service deployment, when compared to requirements of power systems on the U.S. mainland. In addition, the increasing concentration of variable renewable generation in Hawai'i's electric grids further increases the need for ancillary services to maintain reliable and efficient operation. The critical role played by ancillary services in Hawai'i reinforces the need for a DR portfolio that can contribute to meeting the ancillary service requirements of the grid.

The grid service requirements for Hawai'i are characterized in Figure 2. As one moves up the pyramid, grid service requirements call for faster response times, require more constant utility control, and generally become more difficult to serve with DR resources because the communications requirements, response times, and control infrastructure becomes more complex and costly.

Grid service requirements are discussed in greater detail in Chapter 2 of this report.

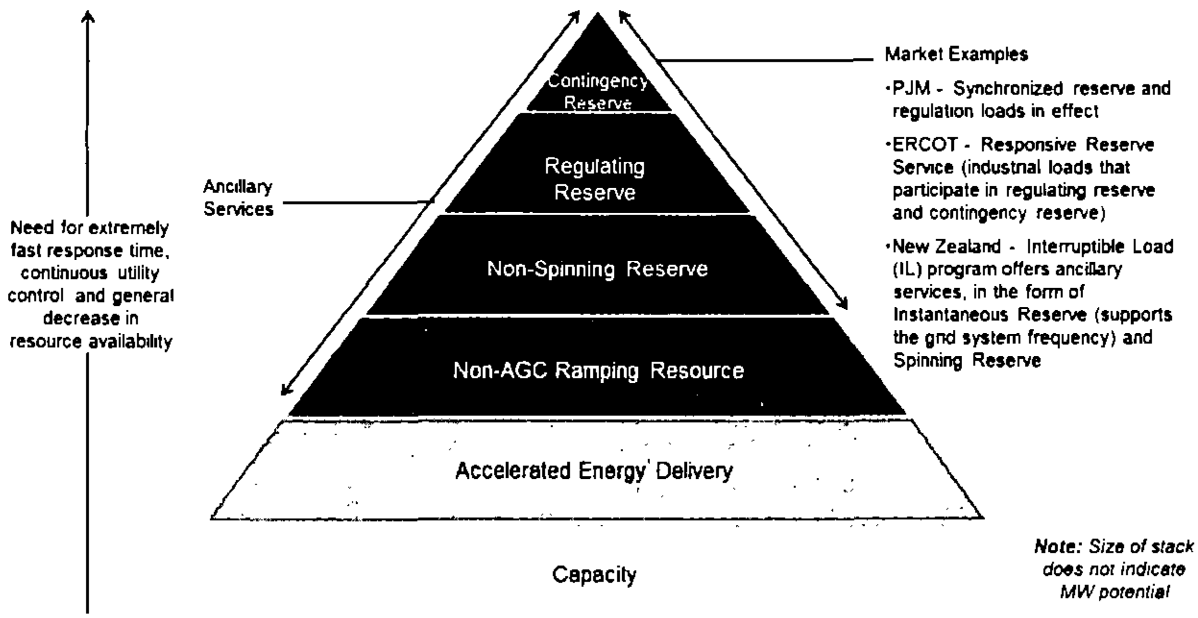

Figure 2: Hawai'i grid service requirements

Assessment of Specific Load Resources Available for DR

The term "end-use demand" refers to a service required by the customer, or the specific appliance being used to deliver that service. The nature of that end use (or load resource) determines whether it is likely to represent an effective DR resource. Some end uses cannot be curtailed or interrupted without a noticeable, and in some cases, negative impact on the end user (e.g., traffic lights, televisions), but there is a wide range of end uses that can effectively be curtailed or adjusted to satisfy various grid service requirements. The magnitude of grid services that can be supplied by curtailing or adjusting such end uses varies based on the size of the customer's demand and the ability to control their specific end uses.

The Companies have evaluated the potential magnitudes of DR opportunities for the residential, and commercial and industrial (C&I)[9] sectors of its customer base. Within the residential sector, attractive loads for potential use in DR programs include air cooling and hot water heating. The Companies have evaluated similar loads in the C&I sector, as well as ventilation, lighting, refrigeration, and customer-sited standby generators. Municipal and privately-owned water and wastewater pumping loads in

[9] C&I sector includes municipal customers.

particular, represent attractive DR opportunities that could help satisfy grid service requirements. The Companies have also evaluated the near- to medium-term DR potential of end uses that are expected to grow, such as electric vehicles (EVs).
To estimate the portions of these end-use loads that can be called upon to satisfy grid services, the Companies used a methodology similar to that defined by Lawrence Berkeley National Laboratory.[10] This approach defines three flexibility filters to evaluate the applicability of specific end uses for DR purposes:

Sheddability refers to the ability of the end use to be curtailed (or in the case of customer-side generation, the ability to serve load);

Controllability refers to the capability, in the form of communications, relaying, and other equipment, to trigger and achieve load shedding, adjusting, or shifting.

Acceptability refers to the willingness of the customer to have a particular end use curtailed or adjusted in exchange for financial incentives.

As highlighted in Figure 3, applying these filters to targeted end uses allowed the Companies to develop demand response programs and projections mapped to respective grid service requirements. For DR implementation the Companies plan to identify respective grid service requirements and let the market determine the most appropriate and cost effective DR resources that could fulfill the needs. Assessing the DR potential in this manner allows the Companies to tailor the initial portfolio of DR programs to the resources available. The DR resource potential is discussed in greater detail in Chapter 3.

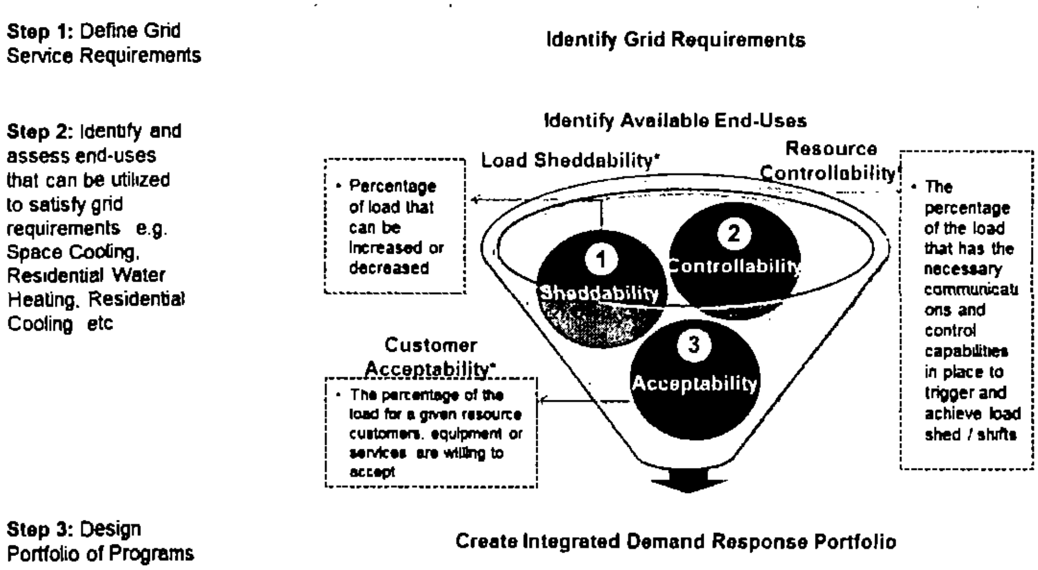

Figure 3: Assessing potential DR resources to meet grid service requirements

[10] Grid Integration of Aggregated Demand Response, LBNL, 2013.

Creation of an Integrated Demand Response Portfolio

The third step in the development of the IDRPP was to create a portfolio of DR Programs. DR Programs were created based on their ability to leverage the estimated potential for DR Resources by customer segment. The objective was to define DR Programs that would provide material combinations of load that could be adjusted up or down, or dispatched on or off, in the interest of meeting the grid service requirements.

For the residential and C&I customers, the Companies intend to expand and modify existing direct load control programs and to launch new direct load control programs on all islands. In addition, "flexible" DR programs will be launched that are designed to target a greater range of ancillary service requirements. The DR programs on all islands will also target customer-sited standby generators. and public and private water companies, all of which are seen as promising DR.

The Companies also propose to launch new pricing programs that would include dynamic and critical peak pricing (CPP) features. These pricing-based programs adjust the retail price of electricity over different time periods of the day to reflect the changing cost of generating and delivering energy throughout the day. Dynamic pricing programs send price signals that encourage customers to shift their load demand to lower overall system operating costs and help assure system reliability.

An important enabler of these new pricing programs is the Companies' smart grid initiative, which will include Advanced Metering Infrastructure (AMI) and internet-based customer portals. AMI will allow the company to measure and verify customers' performance under these new pricing programs. The internet-based portals will provide customers with near real-time information regarding electricity prices, as well as other important information that can help them manage their energy costs.

More detailed descriptions and discussions of the respective DR Programs included in the IDRPP are presented in Chapter 4.

2. Grid Service Requirements and the Role of Demand Response

The design of an efficient and effective demand response portfolio begins with the identification of the grid service requirements that must be met to maintain system security and reliability. Hawai'i utility grids are subject to the same laws of physics as electrical grids worldwide, and thus require similar capacity and ancillary services, but the small scale, high penetration of variable renewable generation, and electrical isolation of island grids present unique challenges due to the nature and scale of the sources and loads.

The smaller power system size and lack of interconnection has always required greater relative volumes of ancillary services in the Companies' systems and necessitated rapid deployment and longer duration. As the concentration of variable renewable energy resources in the Companies' systems continues to increase, so too does the need for grid services. This more acute need, together with the anticipated reduction in the amount of thermal generation that has historically met these needs and the need to lower the price of electricity, motivate the Companies to include DR resources as a fundamental tool in managing the power system supply and demand balance.

In this chapter, grid service requirements are discussed in the context of the Hawai'i electricity grids.

GRID SERVICE REQUIREMENTS ON THE U.S. MAINLAND

The common grid services on the U.S. mainland, along with response speed and duration required are listed in Table 1. These grid services are of two groups: Capacity and Ancillary Services.

While some of these grid services require responses on the order of cycles or seconds, including regulating reserve and contingency reserve, other services do not require such quick response times. Response durations also vary depending on the service. For example, capacity may be needed for three hours to meet its requirement, but inertial response requirement is satisfied during the course of a few seconds.

Grid Service Requirements	Response Speed* (Mainland)	Response Duration
Capacity		
Capacity Used to meet demand plus reserve margin; supplied by on-line and off-line resources, including interruptible load	Minutes	If called, must be available for at least 3 hours
Ancillary Services		
Contingency Reserve Reserves to replace the sudden loss of the single largest on-line generator; supplied from online generation, storage or DR	Seconds to <10 min	Up to 2 hours
Regulating Reserve Maintain system frequency; supplied from on-line capacity that is not loaded	<1 min	Up to 30 min
Non-Spinning Reserve Used to restore regulating reserves and contingency reserves; supplied by off-line fast start resources or DR	10-30 min	2 hours
Black Start Capability The ability of a generating unit to start without system support	N/A	Duration of system restoration time
Inertial Response Local (i.e. at a generator) response to a change in frequency; supplied by rotational mass of generators, or power electronics of inverter-based resources	N/A	2-3 seconds

* Response speed refers to the time needed to "dispatch" a resource, automatically or manually, once it is known it is needed.

Table 1. Grid services and required response speeds and durations on the U.S. mainland

GRID SERVICE REQUIREMENTS IN HAWAI'I

Hawai'i's and U.S. mainland electric grids each require similar grid services, but Hawai'i has unique operational considerations. The nature and volume of grid services the Companies require are a direct product of the isolated nature of the island power systems. System disruptions (e.g. generating unit trips, transmission line faults, extreme ramping of variable renewable resources, etc.) result in more significant impacts (e.g. frequency excursions, voltage fluctuations, loss of load, etc.) on Hawai'i's island grids than they do on larger interconnected mainland grids. Further, individual generating resources in Hawai'i are typically a larger as a proportion of system demand at any given time, which means that the impact of a single-failure contingency is much more severe compared to a single-failure contingency on the mainland. In addition, the size of individual generating units relative to the total system load also results in systems with a high rate of change of frequency compared to the mainland.[11]

These considerations require a robust set of grid service capabilities, particularly with respect to the time frames involved in keeping supply and demand in balance and maintaining system frequency within an acceptable band. Typical mainland power systems can utilize their size, diversity, and interconnections to balance supply and demand. Conversely, within the isolated power systems of Hawai'i, a failure in the deployment of a grid service may result in a system level failure. To be effective the ancillary services on O'ahu, Maui, and Hawai'i need to be faster and available in greater volumes, proportionately speaking.

The more restrictive requirements of Hawai'i, as well as the greater proportions of grid services required, make DR an attractive additional resource option in providing grid services. At the same time, these differences also need to be kept in mind – a resource that can meet a regulating reserve requirement on the U.S. mainland may not be less effective in Hawai'i. A U.S. mainland DR resource will not be discounted out of hand in Hawai'i, but the varied response requirements across like-named ancillary services, U.S. mainland versus Hawai'i, is all the more reason to clearly and carefully establish the nature of the grid service requirements before targeting customer segments and designing programs to meet them.

Notwithstanding these differences, the Companies are committed to exploring and learning from the success of U.S. mainland DR programs used to provide ancillary services. A comparison of the response speeds needed on the U.S. mainland to those required in Hawai'i are shown in Table 2. All the grid services listed require faster response times in Hawai'i, with the exception of capacity and non-spinning reserve.

[11] The maximum size of individual generating units is currently being evaluated by the Companies as part of their development of Power Supply Improvement Plans (PSIP) in the contexts of system security and overall cost for system operation. Therefore, this factor that contributes to the uniqueness of the Hawaiian power systems is subject to change.

2. Grid Service Requirements And the Role of Demand Response

Grid Service Requirements in Hawai'i

Grid Service Requirements	Response Speed* (Mainland)	Response Speed* (Hawaii)	Response Duration
Capacity			
Capacity Used to meet demand plus reserve margin; supplied by on-line and off-line resources, including interruptible load	Minutes	scheduled in advance by system operator	If called, must be available for at least 3 hours
Ancillary Services			
Contingency Reserve Reserves to replace the sudden loss of the single largest on-line generator; supplied from online generation, storage or DR	Seconds to <10 min	Within 7 cycles of contingency event	Up to 2 hours
Regulating Reserve Maintain system frequency; supplied from on-line capacity that is not loaded	<1 min	2 seconds, controllable within a resolution of 0.1 MW	Up to 30 min
Non-Spinning Reserve Used to restore regulating reserves and contingency reserves; supplied by off-line fast start resources or DR	10-30 min	<30 min	2 hours
Black Start Capability The ability of a generating unit to start without system support	N/A	<10 min	Duration of system restoration time
Inertial Response Local (i.e. at a generator) response to a change in frequency; supplied by rotational mass of generators, or power electronics of inverter-based resources	N/A	2-3 seconds	2-3 seconds

* Response speed refers to the time needed to "dispatch" a resource, automatically or manually, once it is known it is needed.

Table 2. Grid services and required response speeds and durations in Hawai'i

Hawai'i response speed constraints given in Table 2 reflect the latest assessment provided by the Companies' System Operation and Transmission Planning teams. More details on the grid service definitions and required response times are as follows:

Capacity: There is no stringent response time required for capacity, but the amount of capacity should be available for up to three hours upon request.

Regulating Reserve: The System Operator uses regulating reserves to balance the system for supplemental frequency control following disturbances and to maintain system frequency in the desired control dead band under normal conditions. Regulating reserve resources must have the ability to respond immediately upon receiving Automatic Generation Control (AGC) command and be capable of increasing and decreasing demand. Regulation must be controllable to a resolution of 0.1 MW by AGC, which emphasizes the importance of two-way communications. To meet regulation requirements, load change must be sustainable for a minimum of 30 minutes. To participate in regulation reserve, an interface to AGC is required, which includes telemetry and control requirements including indication of remaining reserve in both the increasing and decreasing directions. Regulating reserve is continuously deployed on a four-second control cycle.

Contingency Reserve:[12] This is the reserve deployed by the System Operator to meet contingency disturbance requirements. For DR contingency resources, response time from frequency trigger should be no more than 7 cycles,[13] and the response should have an accuracy of +/- 0.02 Hz and +/- 0.0167 cycles.[14]

Non-Spinning Reserve: These reserves can be considered in three different categories: 10-minute reserves, 30-minute reserves, and long lead time reserves. The required response speeds are within 10 minutes, within 30 minutes, and longer than 30 minutes, respectively. 10-minute reserves should provide declared capacity for up to 2 hours.

ADDITIONAL GRID SERVICES OF VALUE IN HAWAI'I

In addition to the grid service requirements described above, Hawai'i's unique power system characteristics, combined with the increasing concentration of variable renewable resources, require additional grid services that provide robust flexibility in terms of serving load. These grid service products are Non-AGC Ramping[15] and Accelerated Energy Delivery,[16] which supplement the ramping ability of the generation fleet to help account for rapid reductions in wind or solar generation and help the Companies mitigate extreme midday load shape impacts.

The two aforementioned grid services unique to Hawai'i are shown in Table 3.

[12] The contingency reserve requirement for the primary protection of the system against sudden generation or transmission outages is set according to the capacity needed to respond to the largest possible single loss contingency on the system at a point in time. On O'ahu, that number is 200-210 MW when the AES plant is online (180 MW for the net load of the unit plus additional contingency reserves). On O'ahu this contingency reserve requirement is currently met through spinning generation reserves, but DR resources could contribute to meeting this requirement if they can respond within less than 8 cycles.

[13] One cycle equals 0.0167 seconds.

[14] The under frequency load shedding scheme utilizes a series of very fast acting (instantaneous) devices to disconnect load during rapid frequency declines. The intent of these load disconnects is to return the frequency to arrest frequency decline to keep a safe operating frequency for the remaining generation. After the operation of the fast-acting (instantaneous) load disconnect, the system frequency may be stable, but lower than what is considered a safe operating frequency. If the frequency is not recovered by remaining generation through deployment of reserves, after a certain length of time, a "kicker" block of load is automatically removed from the system to return the system frequency after a time delay.to the safe region. Contingency Reserves that cannot meet the 7 cycle operation requirement can be used for the "kicker block" of contingency reserve requirements provided such change in load is controllable within an accuracy of +/- 0.02 Hz, +/- 0.0167 cycles and be capable of providing response time from frequency trigger to load removal in adjustable increments of 0.5 seconds up to 30 seconds. AS with all other DR programs, use of DR for this purpose must be designed to ensure that it does not interfere with the under-frequency load shed scheme.

[15] Non-AGC Ramping is a sub-category of Non-Spinning Reserve.

[16] Accelerated Energy Delivery is not an ancillary service requirement.

Grid Service Requirements	Response Speed*	Response Duration
Non-AGC Ramping (a faster sub-category of Non-Spinning Reserve) Resources that can be available prior to quick start generation and can add to system ramping capability	<2 min	up to 2 hours
Accelerated Energy Delivery** Shifting the demand for energy from high demand evening peak periods to lower demand midday periods, or higher demand morning periods to lower demand overnight periods	N/A	N/A

* Response speed refers to the time needed to "dispatch" a resource, automatically or manually, once it is known it is needed.
** Accelerated Energy Delivery is not an ancillary service product of the Hawaii system, but will help meet the need to reduce peak loads and especially to increase overnight and midday demand.

Table 3. Additional grid services needed in Hawai'i

Non-AGC Ramping, which is a subcategory of Hawai'i's 10-Minute Reserve ancillary service, includes resources that provide ramping capability that does not feature response speeds consistent with AGC; however, it is fast enough to be available in 1-2 minutes, and can therefore help mitigate sudden ramp-down events in wind or solar generation. Non-AGC Ramping resources can be used to bridge the time gap to quick start generation (where available),[17] obviate the need to start it altogether, or reduce the fuel use of operating generation. Because the current quick start generation on the Maui Electric and Hawaii Electric Light systems can be online after three minutes and Hawaiian Electric is considering adding generation with similar start times, the response speed requirement for this service is established as less than two minutes.

Accelerated Energy Delivery is designed to shift load from high demand peak periods (usually in the evenings) to lower demand periods (usually during midday, when behind-the-meter solar is reducing net load). The response speed required will not need to be particularly fast, but it will need to be automated. The duration required will need to be at least one hour to be of significant value, and customer compensation will vary according to the amount of time a demand-side resource can be curtailed. For example, a water heater that can be preheated so that it does not contribute to electricity demand from 5 pm – 9 pm may be worth considerably more to the system than one that can only be cycled offline from 6 pm – 8 pm.

Successful deployment of the Accelerated Energy Delivery resource will provide economic benefits for all customers by reducing the total cost of energy production. As discussed later in this section, this service may be important in the near term to address reliability concerns associated with the desire to eliminate minimum generation constraints. Currently, there are various Hawaiian Electric Companies' Rider programs designed to achieve a similar objective, such as Rider M (off-peak and curtailable

[17] On Maui, the 2.5 MW X1-2 and M1-3 at Maalaea Power Plant can start in three minutes and reach full load in another minute.

service), Rider I (interruptible service), and Rider T (time-of-day service) as well as other time-of-use schedules. Ultimately, time-based pricing programs will help "shave the peak" and "fill the valley" of the daily load demand profile, but those programs cannot be effectively deployed until the AMI system is installed. Therefore, in the near term DR programs that can provide the Accelerated Energy Delivery grid service requirement may be beneficial.

The following subsections detail the challenges leading to these two requirements, including declining daytime net demand (demand net of behind-the-meter solar PV, in this case) and increasing supply volatility as variable renewable generation increase across the system. Analysis of the daily load demand profile (net of customer-owned distributed generation) shows decreasing midday demand and an increasing evening peak over the coming years. As the daily curve gets steeper, balancing demand and supply will require significant ramping capabilities and increased levels of responsiveness in grid operations. In addressing these challenges, DR could provide value as another option for balancing supply and demand.

O'ahu

The expected evolution of the daily load demand profile on O'ahu over the next decade is shown on Figure 4. The load shape is a characteristic depiction of the so called "Duck Curve", commonly recognized across the electric utility industry. Currently morning peak is around 850 MW, midday demand goes slightly below 800 MW and the evening peak is above 1000 MW. In the coming years, midday demand is expected to decrease significantly due to increasing levels of "behind-the-meter" solar distributed generation, and will be flanked by increasingly steep peaks (and therefore ramping periods) during the morning and late afternoon.

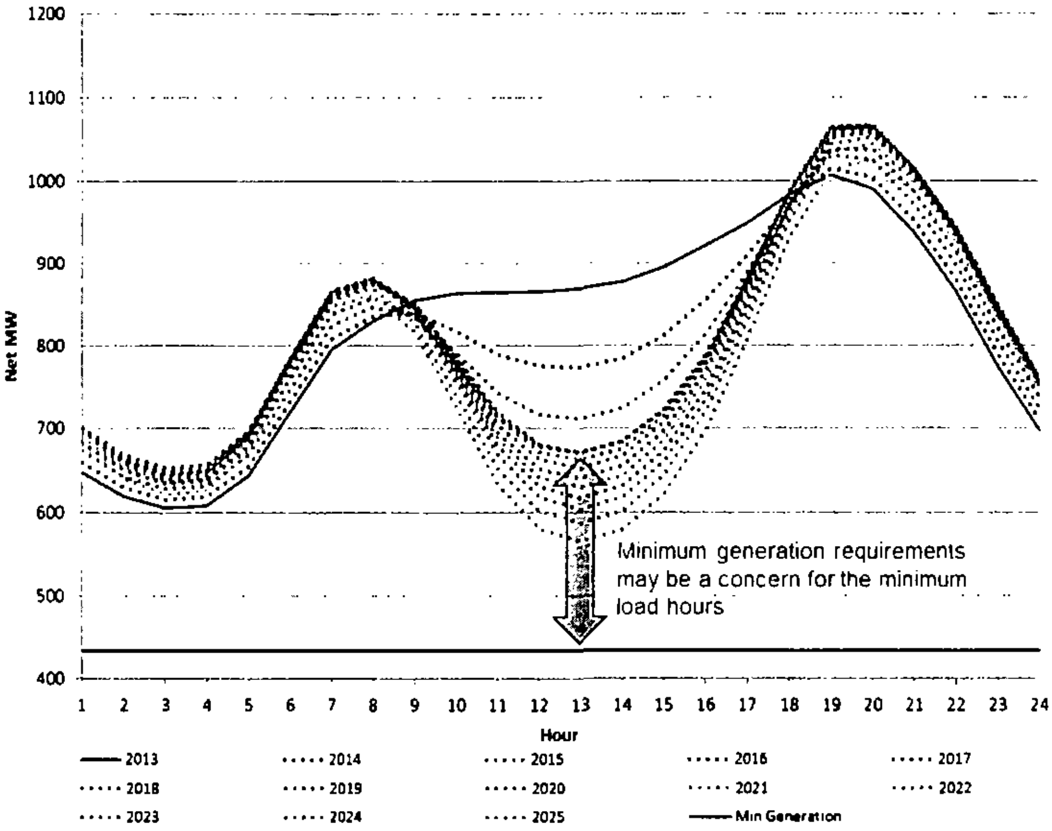

Figure 4. Daily load profile, O'ahu — 2013 actuals, 2014-2025 projections

The recent midday trends are worth noting. Average hourly daytime load from July 2010 through June 2011, as measured at 1:00 pm, exceeded 1,000 MW. From July 2012 through June 2013, average 1:00 pm load was below 900 MW, more than 10% lower. By 2019, under current projections, average 1:00 pm load will be approximately 650 MW. This poses a risk to reliable grid operation on O'ahu and if this projected trend continues, minimum generation requirements could result in daytime curtailment of renewable resources (currently rare).

Increasing levels of solar generation will reduce the net daytime system demand, as discussed above. Though solar generation does not directly affect the evening peak because it typically occurs after solar generation drops off, the annual evening peak demand is also projected to decline in future years due to energy efficiency and pricing programs. In the near term years, however, the annual evening peak is projected to increase year over year. Table 4 summarizes projected annual peak demand, by island, through 2030.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oahu	1173	1195	1203	1223	1228	1238	1238	1227	1213	1200	1193	1160	1113	1066	1019	972	925
Hawaii	191	190	189	189	191	193	194	195	197	197	198	199	197	196	195	194	192
Maui	194	195	198	204	210	214	215	217	218	219	218	219	217	216	212	210	206

Table 4. System peak demand by year (MW)[18]

Declining average daytime minimums and increasing evening peaks translate into increasingly steep ramps in system demand, and corresponding increasing challenges in balancing supply and demand for system operation. To help manage this situation in a cost-effective way, DR can contribute by "shaving the peak" and "filling the valley", whereby a portion of the evening energy needs are shifted to the midday demand period. This important grid service requirement is referred to throughout this document as "accelerated energy delivery."

In addition to the accelerated energy delivery needs, increased levels of minute to minute ramping capability, both up and down, would also be required, primarily to compensate for the variable nature of solar and wind generation. For example, analysis of a month of 10-minute solar data for two 5 MW solar projects on O'ahu, Kalaeloa Solar Two (KLS2), and Kalaeloa Renewable Energy Park (KREP), shows significant variability in the output of these resources, as illustrated in Figure 5. To put this variability in context, increases or decreases of more than 4 MW represent 40% or more of nameplate capacity for these two facilities.

The impact of solar power volatility will become a greater challenge in the future as the combination of distributed and central solar PV generation capacity grows. Depending on the distribution of solar panels across O'ahu and the weather conditions, minute-to-minute drops and increases in solar generation could be highly correlated across the whole solar fleet, which could result in very large swings in net system demand and the load that would need to be served by non-solar PV resources.[19]

[18] Source: Hawaiian Electric's 2014-2030 load projections based on February 2014 Sales and Peak Forecast; Maui Electric's 2014-2030 net load projections as of June 2014 (Maui only); Hawai'i Electric Light's 2014-2030 net load projections as of June 2014.

[19] For example, the number of 10-min fluctuations which are larger than 25 MW and smaller than 50 MW can be more than 200 in a month (roughly 7 in a day) if all the solar power generated from the panels are fairly correlated with each other like KLS2 and KREP.

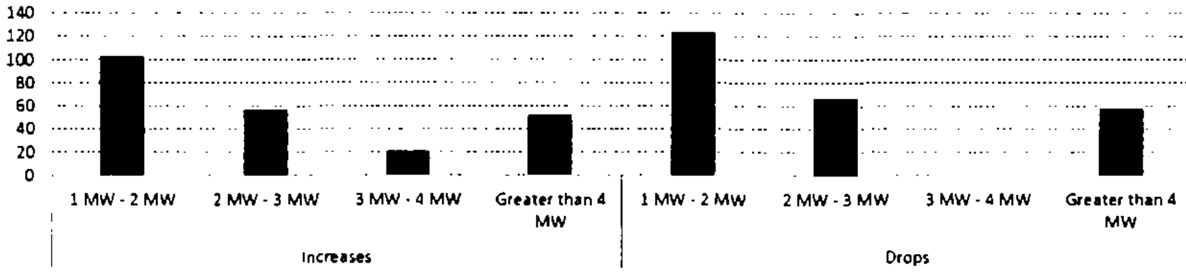

Figure 5. Number of fluctuations in solar power between 10-min intervals in December 2013, KLS2, and KREP combined

O'ahu currently has approximately 250 MW[20] of solar PV, most of it being customer-sited distributed generation. The existing wind capacity on O'ahu totals 99 MW (Kawailoa Wind = 69 MW and Kahuku Wind = 30 MW); this also contributes to the variability of supply-side resources. Planned utility-scale PV projects and additional customer-sited distributed generation (mostly solar PV) will further contribute to supply-side resource variability and will further reduce the midday demand that is served by other resources.[21] DR programs that can offer accelerated energy delivery will be instrumental for cost-effective system operation and for mitigating the reliability risks of variable generation. DR could accomplish this by shifting load to earlier time periods. For example, DR programs that manage water heating on customers' premises, known as grid interactive water heaters (GIWH), could contribute to reducing morning and evening peak load demands and increase midday minimums. Time-based pricing programs could also help mitigate these issues once the AMI system is fully implemented and the energy portals are available to customers.

The need for ramping support is expected to increase over time. Average hourly ramping needs by year are summarized in Table 5, based on Hawaiian Electric's system level hourly net load projection. Unless mitigated through other means, the data shows that the maximum ramping need is projected to be as high as 286 MW per hour in 2020, more than twice the maximum ramping needs observed in 2013. Average ramping needs by hour are expected to increase at a similar pace, as ramping up to meet evening peak is projected to require twice the amount of the 2014 average hourly ramping need.

[20] O'ahu has 254 MW of PV as of June 30, 2014 (all mechanisms).

[21] Net load in this case is demand net of any generation from behind-the-meter customer sited resources.

	Average Change in Load (MW)												
	Actual	Projections				Projections				Projections			
Hour	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	-49	-50	-51	-54	-55	-56	-55	-55	-58	-60	-61	-60	-63
2	-29	-30	-30	-32	-34	-34	-33	-33	-35	-37	-38	-37	-40
3	-14	-15	-15	-16	-17	-17	-16	-16	-18	-19	-19	-19	-20
4	4	4	4	4	4	4	4	4	4	5	5	5	5
5	35	36	38	39	41	41	40	40	43	45	46	45	48
6	77	78	79	83	86	88	85	85	89	92	93	91	95
7	75	76	76	78	79	80	80	80	80	81	81	80	80
8	35	27	23	20	20	19	18	17	16	16	15	14	13
9	25	4	-11	-21	-24	-27	-30	-32	-34	-37	-39	-41	-44
10	9	-22	-45	-60	-65	-69	-73	-76	-80	-83	-87	-89	-93
11	0	-28	-48	-62	-68	-70	-73	-76	-80	-83	-86	-88	-91
12	1	-14	-26	-35	-38	-40	-41	-43	-45	-48	-50	-50	-52
13	4	-1	-5	-9	-10	-11	-11	-11	-12	-14	-15	-14	-16
14	7	11	13	13	14	14	14	15	15	14	15	14	14
15	18	27	34	37	38	39	41	42	42	42	42	43	43
16	27	44	57	64	66	69	71	73	74	74	75	76	76
17	28	54	74	87	92	96	99	102	104	106	108	110	111
18	34	63	85	98	103	107	111	114	116	118	120	122	122
19	23	42	58	67	71	73	76	79	79	81	82	84	84
20	-17	-11	-6	-1	1	2	2	2	5	7	9	8	12
21	-53	-52	-53	-51	-51	-51	-52	-52	-49	-46	-43	-44	-39
22	-72	-72	-73	-72	-73	-73	-75	-74	-72	-69	-67	-68	-63
23	-92	-93	-95	-95	-97	-98	-98	-98	-97	-96	-95	-95	-92
24	-77	-79	-80	-83	-85	-86	-85	-85	-87	-89	-90	-88	-90
Max Down	-127	-138	-157	-182	-237	-212	-192	-228	-209	-226	-272	-220	-251
Max Up	123	149	231	237	211	223	214	286	247	261	250	233	248

Table 5. Projected average hourly ramp-up and ramp-down needs on O'ahu – maximum ramping needs for the whole year are also summarized at the bottom of the table

Hawai'i Island

Hawai'i Island's load shape is also being impacted by an increase in distributed solar PV generation, as shown in Figure 6. Currently, morning peak is approximately 140 MW, midday demand is slightly above 130 MW and the evening peak is slightly below 170 MW. If these trends continue, midday demand will approach 115 MW and evening peak will be roughly 180 MW by 2025.

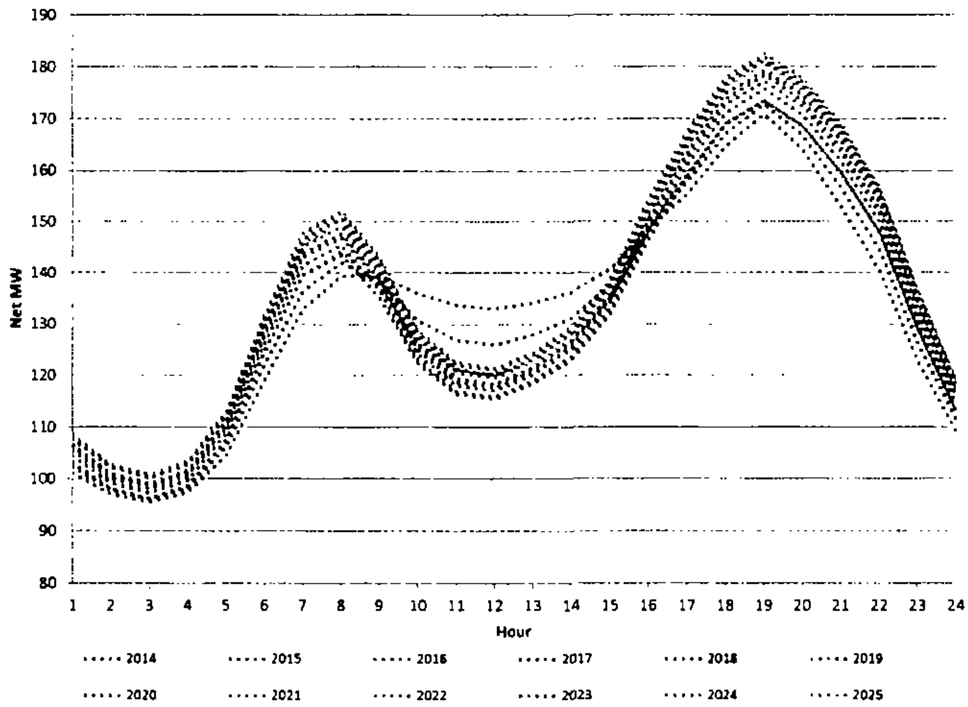

Figure 6. Daily load profile, Hawai'i - 2014-2025 projections

As of April 2014, there was more than 30 MW of installed wind power on Hawai'i, and customer-sited solar PV distributed generation provided more than 28 MW during certain hours of the day. For a power system that has a typical daily peak demand of approximately 180 MW, the current renewable variable generation capacity is already one third of the peak demand. Therefore, as with O'ahu, Hawai'i also has significant ramping needs and fast regulating reserve response rate requirements.

Average hourly ramping needs present similar challenges to that of O'ahu, as shown in Table 6. By 2025, the hourly ramping required between 4 pm and 6 pm will be at least twice the amount of hourly ramping projected for the same time period in 2014. Similarly, maximum ramp-up and ramp-down needed within an hour are expected to be 41 MW and 49 MW in 2025, respectively, compared to 23 MW and 25 MW projected for 2014.

	Average Change in Load (MW)											
	Projections				Projections				Projections			
Hour	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	-8	-9	-10	-10	-10	-10	-10	-11	-10	-11	-11	-11
2	-4	-5	-5	-5	-5	-5	-5	-6	-5	-5	-6	-6
3	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
4	2	2	2	2	3	3	3	3	3	3	3	3
5	7	8	9	9	9	9	9	10	9	10	10	10
6	15	16	17	17	18	18	18	18	18	18	19	19
7	14	14	15	15	15	15	15	16	16	16	16	16
8	6	5	5	4	4	4	4	4	4	4	4	4
9	0	-4	-7	-8	-9	-9	-9	-9	-9	-9	-9	-9
10	-3	-8	-11	-13	-14	-14	-14	-14	-14	-14	-14	-14
11	-2	-4	-5	-6	-6	-6	-6	-6	-6	-6	-6	-6
12	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
13	1	2	3	3	3	3	3	3	3	3	3	3
14	2	3	4	5	5	5	5	5	5	5	5	5
15	4	6	8	9	9	9	9	10	9	9	9	10
16	8	11	13	15	15	15	15	16	16	16	16	16
17	7	9	11	12	13	13	13	13	13	13	13	13
18	9	9	10	10	10	10	10	10	10	10	10	10
19	6	6	5	5	5	5	5	4	5	4	4	4
20	-7	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
21	-11	-10	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9
22	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12
23	-18	-18	-19	-19	-19	-19	-19	-20	-20	-20	-20	-20
24	-14	-15	-16	-16	-16	-16	-17	-17	-17	-17	-17	-17
Max Down	-25	-32	-37	-42	-47	-48	-47	-47	-43	-44	-50	-49
Max Up	23	30	39	38	42	40	41	42	42	40	41	41

Table 6. Projected average hourly ramp-up and ramp-down needs on Hawai'i — maximum ramping needs for the whole year are also summarized at the bottom of the table

Maui

Maui's load shape also reflects impacts from customer-sited distributed generation, as shown in Figure 7. In 2013, average evening peak load was slightly above 160 MW, and midday demand plateaued at approximately 135 MW. However, by 2025, average evening peak is projected to rise to more than 190 MW and average midday net load will decline to roughly 100 MW. Daily ramping requirements will increase with the steeper load shape, and the need to shift load into overnight and midday periods will increase as Maui Electric seeks to minimize curtailment and maintain reliability.

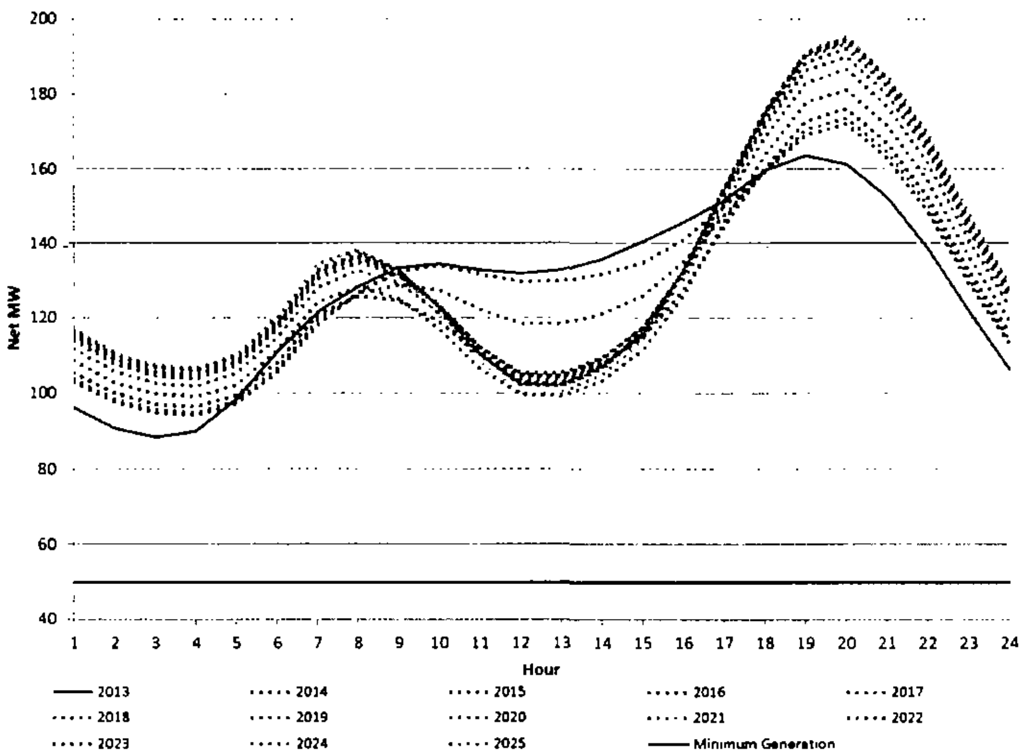

Figure 7. Daily load profile, Maui - 2013 actuals, 2014-2025 projections

With 72 MW of installed wind capacity, Maui's grid already faces challenges to effectively integrate wind into the system. Analysis of 2013 one-minute interval wind data from the Kaheawa Wind Power (KWP), Kaheawa Wind Power II (KWP II), and Auwahi wind farms shows that within one minute, there were 897 increases and 904 drops in wind potential of greater than 10 MW (see Figure 8). This would correspond to roughly five occasions per day where wind generation output increased or decreased by greater than 10 MW in a 1-minute time period.

Currently, the collective ramp rate of Maui's generation facilities is roughly 22 MW per minute when all units are operating. During lower load overnight periods, when fewer units are operating, the ramp rate will be closer to 6-7 MW. Even if 22 MW of up and down ramping was always available, it would not be adequate at all times to reliably integrate wind power into grid. As Figure 8 shows, in 2013 there were a total of 685 fluctuations greater than 22 MW within one minute. Using demand side resources through DR programs to provide ramping support, where available, would bolster the system's up regulation potential and also add to down reserve.[22]

[22] This analysis evaluates the output of the wind turbines themselves, and thus does not account for the impact of the 10 MW battery energy storage system (BESS) at KWP II. Under the Maui Operating Measures, KWP II offers 3 MW of down reserve at all times as well as a quantity up reserve based on the battery's state of charge. While the BESS cannot solve the intermittency

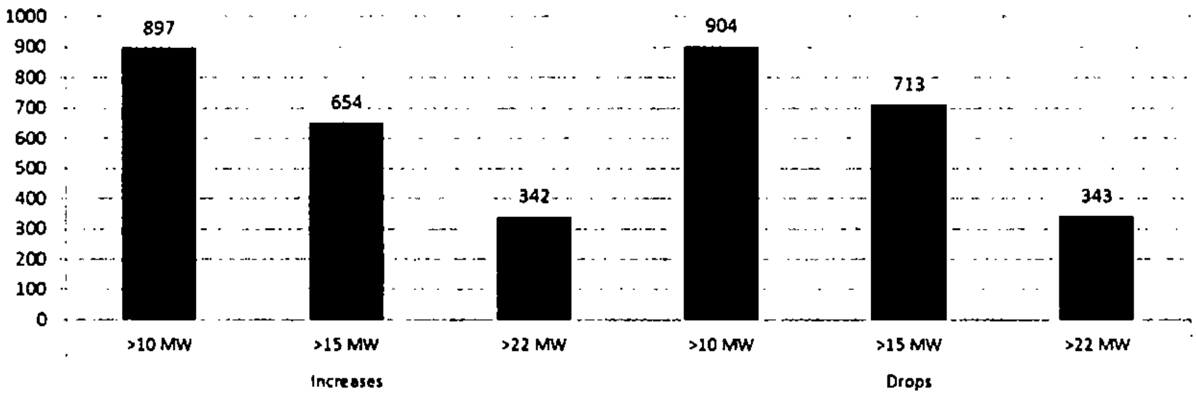

Figure 8. One minute fluctuations in 2013 Maui wind potential, showing frequency by magnitude

Finally average hourly ramping needs by year show similar trends and challenges to that of O'ahu and Hawai'i, as shown in Table 7. Even though maximum ramp-up and ramp-down needs will not change much over the coming years, the average hourly ramping need between 4 pm and 6 pm will almost double by 2025.

	Average Change in Load (MW)												
	Actual	Projections				Projections				Projections			
Hour	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	-10	-10	-10	-10	-11	-11	-11	-12	-11	-11	-12	-12	-12
2	-5	-5	-5	-5	-6	-6	-6	-6	-6	-6	-6	-7	-6
3	-2	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
4	2	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
5	8	3	3	3	3	3	3	4	3	3	4	4	4
6	12	8	8	9	9	9	10	10	10	10	10	10	10
7	11	13	13	13	13	13	14	14	14	14	14	14	14
8	7	9	7	5	4	5	4	4	4	4	4	4	3
9	5	6	3	-1	-3	-3	-4	-4	-4	-5	-5	-5	-6
10	1	2	-2	-6	-8	-8	-8	-9	-9	-10	-10	-10	-11
11	-2	-2	-5	-9	-11	-11	-11	-11	-12	-12	-13	-13	-13
12	-1	-2	-4	-6	-7	-7	-7	-7	-8	-8	-8	-8	-8
13	1	0	0	0	0	0	0	0	0	0	0	0	0
14	3	2	3	4	4	4	4	4	5	5	5	5	5
15	5	3	5	7	8	8	8	8	9	9	9	9	9
16	5	6	9	13	15	15	15	15	16	17	17	17	17
17	6	9	12	17	20	20	21	21	22	22	23	23	23
18	8	9	12	16	18	18	19	19	20	20	20	21	21
19	4	10	11	13	14	14	14	15	15	15	15	15	16
20	-2	3	3	3	3	4	4	4	4	4	4	4	4
21	-9	-9	-9	-9	-10	-10	-10	-10	-10	-10	-10	-10	-10
22	-13	-14	-14	-15	-15	-15	-15	-15	-16	-16	-16	-15	-16
23	-17	-19	-20	-20	-20	-21	-21	-21	-22	-22	-22	-22	-22
24	-16	-16	-17	-17	-17	-18	-18	-18	-19	-19	-19	-19	-19
Max Down	-52	-30	-33	-34	-33	-34	-33	-35	-37	-38	-38	-35	-39
Max Up	51	23	28	34	40	40	41	42	43	44	44	45	45

Table 7. Projected average hourly ramp-up and ramp-down needs on Maui – maximum ramping needs for the whole year are also summarized at the bottom of the table

issues by itself, it can help correct for them. Auwahi also has a BESS, but it used by the project owner to address the wind farm's power quality requirements only, and is not for Maui system use.

The role of DR in meeting the previously described grid services is explained in this chapter. Specific DR programs that address these needs are further discussed in Chapter 4.

ROLE OF DEMAND RESPONSE IN MEETING GRID SERVICES

Demand response is used as a non-generation source of grid services across power systems throughout the U.S. mainland and elsewhere in the world. Several Regional Transmission Operators (RTO) and Independent System Operators (ISO) already allow DR participation in capacity and ancillary services markets, including CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM and SPP.[23] As discussed below, the use of DR to meet capacity requirements in these jurisdictions is relatively mature and well-functioning; the use of DR in ancillary service markets is evolving, although there are examples of successful DR programs that do provide ancillary services (e.g. ERCOT's Load Resource or "LR" program). There are specific and detailed requirements for participation in the ancillary service markets: for example, the ERCOT program has interface requirements for the monitoring and control by the system control center energy management system. These requirements require the DR appear to the energy management system essentially identical to a generator.

Examples of Demand Response in Capacity Markets

In most cases, DR is utilized in capacity markets as a way to reduce peak demand and defer investments for new capacity. In 2012, the average percent of DR potential relative to peak demand was 6% in the aforementioned electricity markets, with ISO-NE having the highest DR potential contribution at 10.7%.[24]

There are recent, successful examples of DR deployment for capacity markets on the U.S. mainland. During the heat wave in the summer of 2013, several electricity markets deployed DR successfully to meet peak demand in a reliable and cost-effective manner. For instance, on July 18, 2013, PJM recorded its system peak at 157,509 MW and

[23] *Assessment of Demand Response & Advanced Metering*, Staff Report by FERC, October 2013. Can be accessed at http://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf. Abbreviations used here stand for California Independent System Operator, Electric Reliability Council of Texas, the New England Independent System Operator, the New York Independent System Operator, the PJM Independent System Operator (which operates a system from New Jersey to Illinois), and the Southwest Power Pool, respectively.

[24] *Ibid.*

dispatched emergency DR for several zones, with DR supplying up to 1,638 MW or 1% of the system peak. Similarly, on September 10, 2013, consumer demand in PJM was observed at a seasonal record-setting 144,370 MW due to unusually hot weather. On top of this, local equipment problems resulted in a potential supply-demand imbalance. Then on September 11, PJM demand fell to 142,071 MW after receiving approximately 5,949 MW from DR resources. This represented the largest amount of DR that PJM has ever received, at 4.2% of system peak. In addition to aforementioned "emergency" utilization of DR resources, there were several successful deployments of DR in the summer of 2013 based on economic dispatch in multiple energy markets.

Examples of Demand Response in Ancillary Markets

While DR participation in capacity markets is well established, the use of DR resources to provide ancillary services is still evolving. According to NERC's Demand Response Availability Data System (DADS),[25] for April-to-September 2011, DR enrollment was primarily composed of direct load control, interruptible load, load as a capacity resource, and emergency, with only 1% of the total committed MW exclusively allocated for spinning (contingency) and non-spinning reserve. For example, during July 2013 in PJM, DR provided 6.1 MW of regulation service out of a total of 851 MW of regulation service procured. Similarly, the following data shown on Figure 9 illustrates that the majority of the DR programs in 2012 were interruptible load, direct load control, or emergency DR, and there were fewer examples for use of DR in spinning, non-spinning and regulation markets.

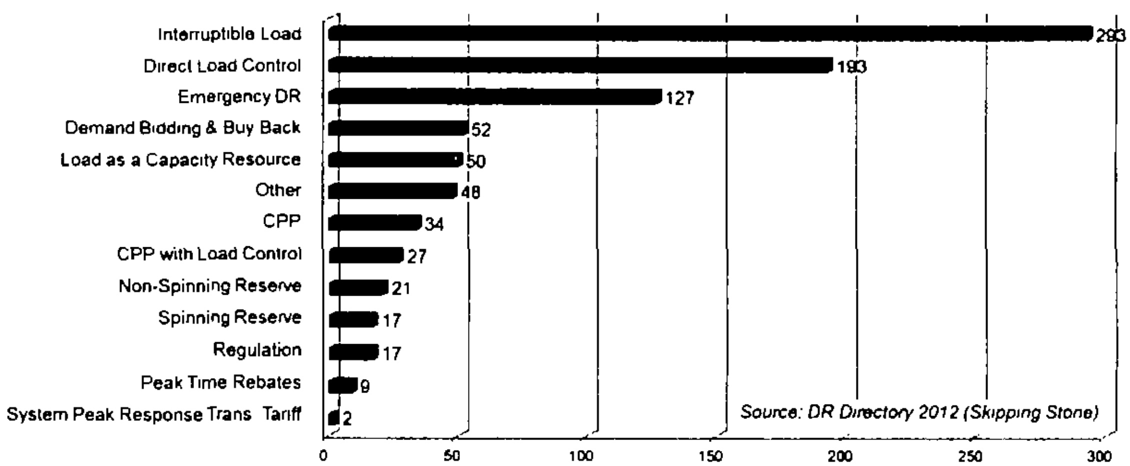

Figure 9. Number of the US DR programs in 2012

[25] Can be accessed at http://www.nerc.com/pa/RAPA/dads/Pages/default.aspx.

In U.S. mainland markets, the quantity of resources cleared for ancillary services represents only a small percentage of the peak demand. For example, regulation and spinning reserves cleared in the PJM and ERCOT markets in 2013 are shown in Table 8. The average hourly quantity of regulation and spinning (contingency) reserve services are both less than 1% of the peak demand.[26] The spinning (contingency) reserves percentage is higher in ERCOT, but still well below the proportion of approximately 15% that is historically typical for the O'ahu electric grid.

Of those DR resources, ancillary services represent a much smaller portion of the total. In 2013, regulation services coming from demand response resources averaged 6.2 MW in PJM — or roughly 1% of the regulation market and 0.004% of the peak demand.

	PJM	ERCOT
Peak Load (MW)	157,141	66,392
Regulation*		
Average volume cleared (MW)	565	445**
% of regulation in peak load	0.4%	0.7%
Spinning (Contingency) Reserve*		
Average volume cleared (MW)	284	2,800
% of spinning reserve in peak load	0.2%	4.2%

** Regulation and spinning reserve are cleared in the RTH market in PJM and in the DAH in ERCOT.*

***ERCOT up and down regulation values were averaged for comparison purposes to PJM's symmetric regulation requirement.*

Table 8. Ancillary services market summary of PJM and ERCOT in 2013

Two major enabling factors that are necessary to fully realize the existing DR potential in ancillary markets are:

1. Provision of technical solutions to enable necessary communication and control infrastructure, and
2. Development of new market rules and business models to effectively increase DR participation.

[26] The average cleared volumes in MW were obtained by summing the total energy cleared in MWh in the markets, and dividing the total by the number of hours in 2013.

Technical factors have until recently been a limitation because real-time control of DR resources was not common or was very expensive.[27] That limitation is being addressed by equipment vendors and specialized telecommunication service providers, but in practice, most utilities are still in the process of adopting smart grid technologies and upgrading their underlying communications infrastructure, which takes time, investment, and resources.

The development of new market rules is equally important, both in achieving high DR participation rates from customers and in maintaining efficient markets for the ancillary service needs of the grid. Market rules and business models should be designed carefully to fit needs of a specific utility's customers and the systems operator, and they should also be flexible enough to meet changing load demand characteristics.

When reviewing the development of DR ancillary markets globally, the impacts from these two factors can be observed in almost all cases. Utilities are going through phases of deploying enabling technologies, while at the same time drafting and experimenting with emerging business models. A brief review of the use of DR to provide ancillary services in PJM, ERCOT and New Zealand is provided in Appendix A.

Role of Demand Response in Hawai'i

In view of the ancillary service requirements that exist on the isolated power system in Hawai'i and the challenge of high concentrations of renewable variable generation, increased use of DR resources are expected to cost-effectively provide needed grid services for effective system operation.

The grid services requirements in Hawai'i (including specifications) are shown in Table 9, including an indication of whether DR can be relied upon to provide such services. DR is technically capable of providing all the required grid services except Black Start and Inertial Response. Black Start, by definition, applies to supply-side resources only. Inertial Response is typically supplied by rotating machinery such as generators. Its response can be mimicked by fast acting storage with droop or similar control. DR that is capable of fast acting droop control could be used for inertial or fast acting reserves, however, droop controlled DR is an emerging technology and its ability to respond in this time frame is not currently possible. The Companies will continue to monitor the

[27] For example, a customer that wishes to participate as a "Load Resource" in ERCOT's ancillary services market has in the past been required to install telemetry equipment and under-frequency relaying that is equivalent to that required for a utility-scale generating resource interconnected to the ERCOT system. This requirement has effectively limited participation of demand-side resources in the ERCOT ancillary service market to very large industrial customers who can justify the expenditure on the required equipment.

ability of DR technologies to meet Inertial Response requirements and will pursue it via DR programs if and when appropriate.

Grid Service Requirements	Response Speed* (Mainland)	Response Speed* (Hawaii)	Response Duration	Potential for DR?
Capacity				
Capacity Used to meet demand plus reserve margin, supplied by on-line and off-line resources including interruptible load	Minutes	scheduled in advance by system operator	If called, must be available for at least 3 hours	✔
Ancillary Services				
Contingency Reserve** Reserves to replace the sudden loss of the single largest on-line generator, supplied from online generation, storage or DR	Seconds to <10 min	Within 7 cycles of contingency event	Up to 2 hours	✔
Regulating Reserve Maintain system frequency; supplied from on-line capacity that is not loaded	<1 min	2 seconds, controllable within a resolution of 0.1 MW	Up to 30 min	✔
Non-Spinning Reserve Used to restore regulating reserves and contingency reserves; supplied by off-line fast start resources or DR	10-30 min	<30 min	2 hours	✔
Non-AGC Ramping Resources that can be available prior to quick start generation and can add to system ramping capability	N/A	<2 min	Up to 2 hours	
Black Start Capability The ability of a generating unit to start without system support	N/A	<10 min	Duration of system restoration time	✖
Inertial Response Local (i.e. at a generator) response to a change in frequency; supplied by rotational mass of generators, or power electronics of inverter-based resources	N/A	2-3 seconds	2-3 seconds	✖
Other				
Accelerated Energy Delivery*** Shifting the demand for energy from high demand evening peak periods to lower demand midday periods, or higher demand morning periods to lower demand overnight periods	N/A	N/A	N/A	✔

* Response speed refers to the time needed to "dispatch" a resource, automatically or manually, once it is known it is needed
** Contingency reserves that cannot meet the 7 cycle operation requirement are not fast enough to serve as primary protection resources (e.g. spinning reserves) but may be able to meet the contingency reserve requirements consistent with the "kicker block" of secondary resources
*** Accelerated Energy Delivery is not an ancillary service product of the Hawaii system, but will help meet the need to reduce peak loads and especially to increase overnight and midday demand

Table 9. Role of DR in meeting the grid services in Hawai'i

Several technologies may be leveraged to meet the capacity and ancillary needs of the Hawaiian grids. Examples include: Variable Frequency Drives (VFDs) for water pumps and other motor loads, LED lighting, refrigeration, ventilation, GIWH, and others. All of these options will be discussed in detail in Chapter 4. Ultimately, the Companies will look to the market to determine the customers and associated DR resources that can meet the requirements of the Companies' DR program specifications most efficiently.

Maximum Amount of Electric Load that Demand Response Can Serve

Hawaiian Electric Companies system operators can employ demand response programs up to the stability limit of the system. This limit is defined by the largest contingency, the amount of protection reserves, and the amount of load required to stabilize the system following the activation of the protection reserves. The estimated maximum amount of DR that could be employed during peak evening conditions at present on the O'ahu electricity grid is approximately 15% of the system load depending upon the contingency reserves of the system. The estimated amount of DR during other system conditions will vary based on actual operating conditions and the amount of distributed generation on the system.

The Delicate Balance Between Demand and Supply

All electric systems maintain the delicate balance between load demand and supply. This balance must be maintained during normal operations as well as following system contingencies (abnormal operations).

The change in system frequency is an indicator of whether the power system supply and demand is balanced. If the power supply and the load demand are equal, the system frequency will be a constant value. For the Companies' five island grids, the target frequency is 60 Hz (60 cycles per second) with an acceptable range for normal operation (called steady state) from 59.7 to 60.3 Hz (the desired range is 59.95 to 60.05 Hz). If the amount of load on the system exceeds the power supply, the system frequency will decline.

In the immediate time frame, responsive generation acts to resist changes in frequency through the action of its governor droop control – this is 'primary frequency response'. System frequency is restored to the target range by supplemental frequency control from the regulating reserves. Regulating reserves are deployed to bring system frequency towards the target byAGC, which operates on a periodic cycle of 4-10 seconds depending on the system and operating conditions. If there are insufficient reserves online for the second-to-second management of system balancing within the near term, additional regulating reserves are deployed. In order to participate in regulating reserves, DR must be able to be deployed to increase or decrease demand in a controlled fashion on the AGC control cycle, with the results observed by the next AGC control cycle. Due to the amount of variable generation on the system, which case imbalance and frequency error on the island systems, regulating reserves are utilized extensively.

An electric system must also be able to withstand major contingency events, such as the sudden loss of a generator or major transmission line. When a major generation contingency event occurs, the amount of generation on the system suddenly plummets while demand remains constant. Frequency rapidly decreases since there is more load than generation. System protection must respond virtually instantaneously to correct this imbalance—a response time that is much, much faster than an AGC or DRMS can handle—to keep the system from collapsing (in other words, causing an island-wide blackout). For each of the Companies' five island grids, system protection must respond within seven cycles (i.e. within about 0.117 seconds).

The most common, and most successful, method for restoring the system frequency to an acceptable level is to immediately shed load, usually through automatic system relays that disconnect load from the system to a level that helps restore the balance between load and the generation remaining on the system. This immediate reaction—the under-frequency control program—is the most critical component of an island electric system for maintaining system reliability. An under-frequency control program that fails to quickly restore system frequency to a safe operating level presents a severe risk of catastrophic collapse for an electric power system.

To operate properly, the under-frequency control programs in the Companies' five grids must always have sufficient reserves – Protection Reserves – to protect against the most severe mismatch between load and generation that can occur. The Protection Reserves cannot be used to meet any other ancillary service requirement (such as contingency reserves or regulating reserves) or for any other purpose that might not leave this load available for the automatic load shedding necessary during a system contingency. For the Companies' Hawaiian Electric island grids, these Protection Reserves typically account for 50-65% of load demand on the system at any given time. This large percentage directly relates to the generation contingency the system is designed to survive. DR programs must ensure that the amount of load utilized in the DR program does not utilize loads required for Protection Reserves.

A Mainland Perspective on System Balance

In larger systems (such as the western United States mainland), the loss of even the largest generator represents only a small portion—about 2%—of the total generation on the electrical system. As a result, when such a unit is lost, the decrease in frequency is relatively slow. This slow decline allows other generators enough time to respond to correct the mismatch between generation and load and keep system frequency balanced. Under-frequency control programs on these large systems require a range of 25–28% of Protection Reserves to ensure system reliability. The Western U.S. mainland requires the system load shed relays to operate to clear the load within 14 cycles (0.233 second) to respond to these system contingencies.

System Balance on the Companies' Power Grids

While one generator represents only a small portion of the overall generation on a mainland power grid, the situation is markedly different in any of the Companies' five grids. On O'ahu, for instance, the largest generator represents almost 30% of the grid's minimum load and 20% of the peak load. A sudden loss of the largest unit creates a severe under-frequency contingency. Such a contingency would only be exacerbated during an earthquake, hurricane, or lightning storm, when the risk of losing more than one generator is higher.

On O'ahu, the drop in frequency that results from the loss of one generator can cascade into the loss of another generator or the loss of large amounts of distributed PV generation. This has happened in recent unit trips of the largest generator on the Hawaiian Electric system. Such a situation increases system generation loss from a 200 MW unit trip to a 260 MW contingency event. This results in an even greater and more rapid decline in system frequency. In turn, the under-frequency control program then responds by shedding even greater amounts of load. However, the load-shedding schemes in the Companies' systems are designed to survive the loss of multiple generators and large amounts of load, but only because the Protection Reserves account for large amounts (60%) of load.

Following such a contingency event, the power system is almost always in a very fragile state. The amount of generation and load on the system has been drastically reduced. To stabilize the power system and begin its recovery, generation controls must remain operational and approximately 25% of system load must remain connected. Thus, the under-frequency control program must have 85% of system load available – 60% for Protection Reserves and 25% for stabilization – to be effective in resolving the largest system contingencies. This load is not available for demand response. Thus, at any moment in time the remaining 15% of system load represents the maximum amount that can be allocated demand response for system operation. In order to deliver up to 15% of system load via DR resources will require subscription of DR resources that amount to substantially more than 15%.

The amount of load available for DR can also be affected by customer-sited distributed PV generation. Absent distributed PV generation, the level of demand response can approach 15% of system load. As customer-sited PV generation increases, the amount of load capable of being deployed through a DR program decreases. During periods of the day when PV is at its maximum, DR may not be employed (unless the DR program shifts load into the midday period when net system demand is decreased due to the customer-side PV resources), but all DR would be eligible for deployment as PV begins to decrease.

Smaller, more flexible generators might reduce the amount of Protection Reserves required by the automatic load shedding program. This reduction in Protection Reserves could increase the amount of load available for DR programs.

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3. Review of Previous Studies on Hawai'i's Demand Response Potential

Evaluating and understanding the nature and potential magnitude of the available DR resource in Hawai'i is important to the DR portfolio design. The Companies have commissioned or themselves completed several studies in recent years, ranging from class load studies to evaluations of demand response potential. The findings of these studies establish the foundation for the DR potential assessment detailed in Chapter 4, and brief summary is provided in this chapter.

SCOPE OF REVIEW

As part of the efforts to estimate the DR potential for the Companies, major studies and analyses relevant to DR that have been conducted within the last few years were reviewed. These analyses and studies included:

- "HECO IRP-4: Energy Efficiency Potential Study", Global Energy Partners, 2008
- "Assessment of Demand Response Potential for HECO, HELCO and MECO", Global Energy Partners, 2010
- "EnergyScout Impact Evaluation, Hawaiian Electric Company's Direct Load Control Programs", KEMA, 2011
- Class Load Studies of Hawaiian Electric (2012-2013), Hawai'i Electric Light (2008-2009) and Maui Electric (2009)
- "Field Evaluation of Grid Interactive Water Heaters", EPRI, 2013
- Maui Electric Demand Response Survey, Kanu Hawaii, 2013

- Maui Electric Community Interviews to Measure Potential Grid Interactive Water Heater Demand, Kanu Hawaii, 2013
- Commercial generator surveys conducted at Hawaiian Electric in 2014, and at Maui Electric in 2013
- "Demand Response Feasibility Study Phase 1", Maui Electric, Brown & Caldwell, 2014

In addition to the list above, other assessments completed by the Companies and submitted as part of the filings with the Commission were also reviewed. Some of these included surveys completed by customers, which investigated the DR participation potential in Hawai'i.

UNDERSTANDING THE DEMAND CHARACTERISTICS DURING PEAK PERIODS

Which Customers Drive Peak Demand?

It is important to understand the underlying characteristics of demand on the Companies' systems. Figure 10 shows the results for all islands of the most recent Coincident Peak Demand Analyses,[28] which break down contributions to system peak by customer class. Residential customers are a major contributor to the system peak demand on all islands. In the case of Hawaiian Electric, large C&I customers were the largest contributor to peak demand, representing 38% of peak load. Across all islands, small C&I customers' contribution to peak demand is negligible compared to other segments.

[28] At the time of writing this report, the most recent Coincident Peak Demand Analyses for Hawaiian Electric, Hawai'i Electric Light, and Maui Electric were from the 2012-2013, 2008-2009, and 2009 Class Load Studies, respectively.

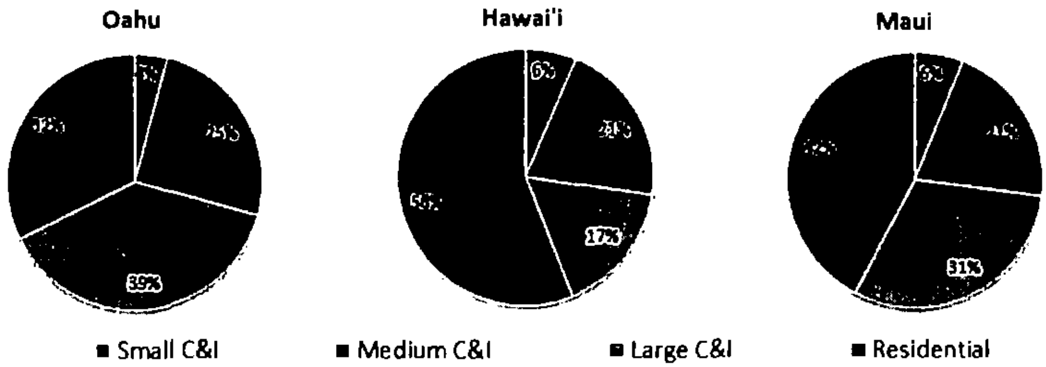

Figure 10. Contribution to system peak by customer class[29]

These results are a snapshot from the system peak event, a fact that illustrates quite well the focus until fairly recently with system peak (and in finding opportunities to reduce it). These remain the best proxies available for targeting initial DR program development efforts, in spite of the fact that the programs to be developed will significantly expand the purview of DR well beyond capacity deferral.

Hawaiian Electric and Maui Electric customer breakdowns indicate that significant DR opportunities may exist in all classes, except for small C&I customers. For Hawai'i Electric Light, the breakdown suggests that focusing on residential and medium C&I customers at the initial stages of program development may result in larger, earlier benefits.

C&I customers are typically regarded as the more attractive target segments for DR programs because of the larger amounts of load available and larger electricity cost mitigation opportunities per customer. In Hawai'i, a more balanced approach is appropriate. Individual C&I opportunities are smaller, and residential customers represent a larger percentage of peak load compared to typical mainland systems. The Companies will aggressively pursue programs with larger C&I customers, particularly the municipal and private water companies with their large water and wastewater pumping loads.[30] The IDRPP also proposes expansion of the successful Residential Direct Load Control (RDLC) program on O'ahu, and launches of similar programs on Maui Electric and Hawai'i Electric Light.

[29] For the purposes of classifying rate classes, class G was categorized as small C&I, class J as medium C&I, and class P as large C&I. Some classes, such as H, F and K, had insignificant demand during system peak, and therefore were omitted from the charts. For Maui Electric, only the CLS data from the Maui Division were used.

[30] For example, MECO recently completed an analysis of the potential for DR resources from the County of Maui Water and Wastewater operations. See Demand Response Feasibility Study Phase-1, MECO, Brown & Caldwell, 2014.

What are the Predominant End-Uses of Electricity in Each Customer Class?

The "*Energy Efficiency Potential Study*" conducted in 2008 provides a breakdown of end-uses on O'ahu.[31] For the other Hawaiian islands, similar breakdowns of end-use characteristics have been assumed for purposes of the IDRPP. As part of the study, a base case was created to estimate the breakdown of energy usage by customer class[32] as shown in Table 10.

	End-use	% of Peak Demand	Notes
RESIDENTIAL	1) Cooling	31%	Contribution to peak demand by single-family and multi-family dwellings are similar.
	2) Water Heating	14%	
	3) Lighting	13%	
	4) Refrigeration	12%	
	5) Other	30%	
COMMERCIAL	1) Lighting	45%	The following building types are included in the commercial sector category: office, hotel, resort, restaurant, retail, grocery, school and other. Retail, office, school are the top three building types contributing to peak demand. Highest contribution to lighting is by schools, followed by retail. Highest contribution to cooling is by small and large offices
	2) Cooling	17%	
	3) Ventilation	7%	
	4) Other	31%	
INDUSTRIAL	1) Motors	76%	More than half of the contribution from the motors are due to pumping.
	2) Refrigeration	5%	
	3) Lighting	4%	
	4) Other	15%	

Table 10. Contribution of end uses to the peak demand by customer class (O'ahu)[33]

The predominant electricity usage in the residential class is cooling at 31% of the total residential demand during peak hours. Cooling is followed by water heating at 14% of residential demand. Both of these categories are significant DR resources, and to some extent are already utilized in existing DR programs in the Hawaiian Electric system.

In 2013, Hawaiian Electric's RDLC program had 32,000 participants in the water heating program and 4,000 participants in the air conditioning program. Assuming 0.44 kW of peak load reduction per water heater, and 0.65 kW peak load reduction per air conditioner, O'ahu can achieve approximately 14 MW of peak load reduction from the water heating program and 2 MW of peak load reduction from the air conditioning

[31] During the 2012-2013 time period, Evergreen Economics, Hawaiian Electric and KIUC conducted a set of surveys in an effort to collect statewide baseline data for the Public Utilities Commission. However, at the time of writing this report, there was no comprehensive document of the completed surveys, detailing the end-uses for each customer class, and therefore the 2008 Energy Efficiency Potential Study was used as the primary resource for end-use data.

[32] For more details on the analytical framework and methodology used on the base case, see Chapter 3 of the Energy Efficiency Potential Study report.

[33] Adopted from Energy Efficiency Potential Study by Global Energy Partners, 2008

program.[34] The actual load reductions have been lower due to switch failures or availability of water heaters at the time of the event. An analysis of the 2013 water heater load shed events at Hawaiian Electric revealed that when called upon during peak hours, on average 10 MW of capacity was delivered. The range of estimated load shed values recorded for four different time periods during the day, drawing from 50 total events, is shown in Figure 11 (boxes represent minimum and maximum values, and the white diamonds represent the averages).

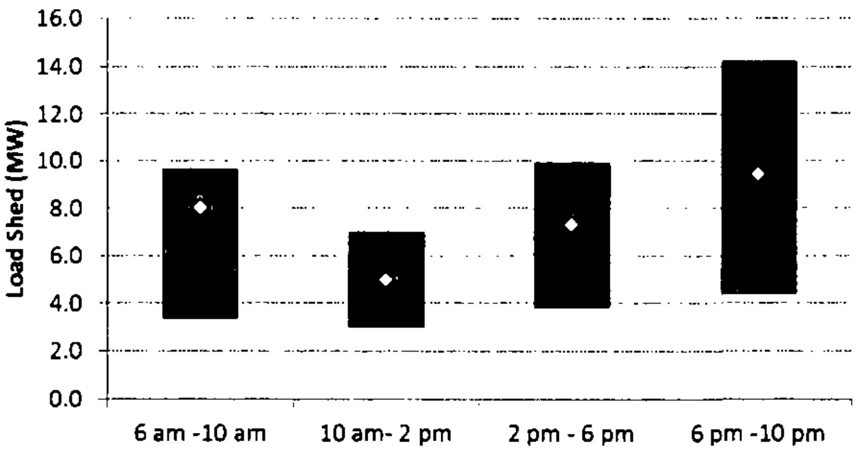

Figure 11. RDLC water heater program load shed statistics, 2013

There are currently no RDLC programs on Maui, but a recent survey revealed that 69% of customers are willing to consider a DR program involving their water heater, and 62% are willing to consider a DR program involving their air conditioning.[35] The Companies intend to implement RDLC DR programs involving water heaters on Maui and Hawai'i based, in part, on the success of the DR program on O'ahu.

GIWH is another promising technology to utilize water heaters as a DR resource. GIWH is an emerging technology that has a much wider temperature range and/or a larger tank capacity than the typical water heater. They can be controlled remotely, on a continuous basis, and allow water to be heated well before it is needed, and to temperatures well above those that are needed, effectively shifting load throughout the operating periods to help meet the Accelerated Energy Delivery grid service requirement. In fact, a pilot study completed by the Electric Power Research Institute in 2013 demonstrated the capability of a GIWH DR Program to meet Accelerated Energy Delivery requirements.[36] Comparison of the power demand characteristics of the three units deployed on O'ahu

[34] EnergyScout Impact Evaluation, Hawaiian Electric Company's Direct Load Control Programs, KEMA, 2011.

[35] MECO Demand Response Survey, Kanu Hawaii survey via Facebook, 2013.

[36] Field Evaluation of Grid Interactive Water Heaters, Supplemental Project Agreement SDF/TC 018378-11156, November 2013.

illustrated the benefits to be gained from "charging-up" during off-peak hours and "discharging" during peak hours.

With their ability to be remotely turned on and off rapidly, GIWH are also expected to be a source of regulating reserves, potentially to counterbalance the intermittency of a given wind or solar power source. A simulation of the results showed that approximately 6,300 units would be needed to effectively counterbalance the frequency excursions associated with a 30 MW wind farm on Maui. Furthermore, results indicate that customer comfort is not affected by the controlled use of GIWH, and surveys point to strong customer interest.[37]

Economic and especially regulatory[38] economic hurdles must still be cleared. As a result of the prevailing regulatory risk, the Companies have been relatively conservative in their projections regarding GIWH. However, the Companies are very excited about the technology's ability to contribute to regulating reserve and accelerated energy delivery and will continue to pursue it aggressively.

Lighting represents approximately 45% of the electricity use during the peak demand by commercial customers. Many commercial customers have recently completed or are planning to complete LED lighting projects, and this may result in lowering the contribution to peak demand from lighting in the future years. Because of the ability to dim LEDs to approximately 85% of their full output with no immediately discernable impact (as long as it is not done too quickly), LED lighting is of interest as a DR resource. To expand the availability of LED lighting as a potential DR resource, the Companies intend to collaborate with Hawai'i Energy to further installation of LED lighting systems with the necessary controls to enable use as a DR resource.

Electric motors represent approximately 76% of the total industrial demand. The majority of the demand from motors is attributed to water and wastewater pumping, which accounts for 60% of the industrial motor-based load. In many applications, pumping hours can be shifted or amounts varied during the day with little or no impact on the operations of the customer. With the proper control equipment and incentives, pumping load is one of the most promising "Regulating Reserve" DR resources. A successful example has been demonstrated in PJM as a result of collaboration between Pennsylvania American Water and the aggregator Enbala Power. In the demonstration completed in 2011, a pump station with a peak demand of 1,650 kW provided

[37] MECO Demand Response Survey Final Report Draft, Kanu Hawai'i, October 2013.

[38] EPRI's November 2013 "Field Evaluation of Grid Interactive Water Heaters" report included the following statement: "The DOE requested comments and feedback based on the concerns that the utility programs designed for peak load shifting (off-peak water heating) will be adversely impacted due to amended energy standards beginning on April 16, 2015 (banning of resistance water heaters with storage cap of > 55 gallons)."

approximately 200 kW of DR capacity, using Variable Frequency Drive (VFD) and other control equipment.[39] Since then, the facility bid into the live PJM market to balance real-time supply and demand. The impact for the customer has been significant, as the VFD pumps were able to reduce 2-3% of the site's total energy cost, reducing costs by approximately $20,000 annually.[40]

Despite proven success of using water pumps as DR resources on the U.S. Mainland, a Demand Response Program Feasibility Study prepared by Brown & Caldwell for Maui Electric in 2014 found that there are some limitations to shifting pumping loads at the water facilities in Maui. These water facilities, the County of Maui's Department of Water Supply (DWS) and the Department of Environmental Management's Wastewater Reclamation Division (WWRD), expressed concerns about the concept of a DR program based on pumping assets. For example, existing water storage tanks are relatively small in relation to well pump capacities, and the current load patterns show that most pumping already happens during off-peak hours. With increasing population in the region, any operational constraint on the pumping schedule would increase water supply risks for the residents. Instead, both the DWS and WWRD support exploring DR opportunities associated with their on-site generator operation. This could represent up to 6 MW of capacity for export to the grid, if the proper permits and approvals can be obtained.

In fact, customer-sited stand-by generators located elsewhere, and owned or controlled by existing C&I customers are also a potential DR resource. These generators are already being utilized as backup generation in the CIDLC program on O'ahu. The Companies envision having standby generation play a greater role going forward, which would involve water and wastewater facilities. In some cases, backup generation is oversized relative to the customer load it supports, so the ability to harness the potential of those generators directly could offer more capacity than total curtailment of the load it supports. A recent study[41] shows that there may be more potential available on O'ahu with minor upgrades and additional permitting.

[39] Pennsylvania American Water Connects to the Smart Grid, by Enbala Power Networks, accessed online at http://www.enbala.com/ in June 2014.

[40] Typical payment range for Grid Balance services in the PJM market has been $35,000-$50,000 per MW, *Ibid.*

[41] Hawai'i Electric Companies Customer Generator Survey, prepared by IPKeys Technologies LLC in April 2014.

DEMAND RESPONSE POTENTIAL BY ISLAND (ESTIMATED PREVIOUSLY)

A comprehensive study[42] was conducted in 2010 to estimate the DR potential in the Companies' systems. The study assessed the DR potential in two main categories: (1) DR for peak load reduction, and (2) Fast DR[43] for ancillary services. Total DR potential for peak load reduction was estimated at approximately 10% of the peak demand in both 2020 and 2040, as shown in Table 11. Fast DR for ancillary services was estimated at approximately half of the peak load reduction potential.

	Peak Load Reduction (customer level impacts)				Fast DR for Ancillary Services	
	2020 (MW)	2020 % of Peak	2040 (MW)	2040 % of Peak	2020 (MW)	2040 (MW)
Hawaiian Electric	161	11%	219	12%	91	109
Hawai'i Electric Light	19	9%	29	10%	12	16
Maui Electric	21	11%	28	12%	10	13

Table 11. Realistic achievable DR potential identified in the 2010 DR assessment study[44]

Based on previous assessments, the potential capacities of DR resources for each island and the respective DR programs are tabulated in Table 12. A large proportion of the estimated figures are attributable to dynamic pricing programs.

[42] Assessment of Demand Response Potential for HECO, HELCO and MECO, Global Energy Partners, 2010.

[43] The aforementioned study by Global Energy Partners considered "Fast DR" to represent "Ancillary Services", and defined the response time requirement as 10 minutes or less within event notification. (Note: Per the Companies specifications for ancillary services, a 10 minute response time would only be fast enough to meet the Non-Spinning Reserve grid service requirement).

[44] Adapted from Assessment of Demand Response Potential for Hawaiian Electric, Hawai'i Electric Light and Maui Electric, Global Energy Partners, 2010

	Hawaiian Electric	Hawai'i Electric Light	Maui Electric
Residential Direct Load Control	33	4	3
Residential Dynamic Pricing	83	12	12
C&I Direct Load Control	2	1	1
C&I Dynamic Pricing	15	1	2
C&I Curtailable	23	1	2
C&I Demand Bidding	4	0	0
Total	161	19	21

Table 12. Breakdown of DR programs and 2020 realistic achievable potentials identified in the 2010 DR assessment study[45]

Since this assessment was completed, there have been important changes in the Companies' projections related to electricity sales, as well as developments in enabling grid technology in Hawai'i. For example, the peak demand projection changed significantly due to energy efficiency programs, and therefore it is less likely that the capacity representation in Table 11 will hold true in the coming years. For Hawaiian Electric, the 2020 system net peak demand projection dropped from 1464 MW to 1238 MW, and for 2030, it dropped from 1991 MW to 925 MW, based on the latest sales and peak demand forecasts. Similarly, Maui Electric and Hawai'i Electric Light's projected system net peak demand figures dropped from the levels assumed in the 2010 GEP study.

Increasing concentration of renewable variable generation in the coming years will add complexity to grid operations, and ancillary services will correspondingly be more valuable. This complexity presents an interesting opportunity for the potential growth of DR programs. However the "Fast DR" resources envisioned in the 2010 study are not fast enough to meet most of the ancillary service requirements, particularly given the unique power system characteristics of Hawai'i.[46] As a result, the Fast DR figures shown in Table 11 are not representative of the DR quantities available for ancillary services in Hawai'i.

Conversely, it is evident from the increasing participation of DR resources on the U.S. mainland that DR will play a major role in the provision of ancillary services. Smart grid applications such as advanced communication and control technologies, and implementation of new business models to incentivize participation will enable greater

[45] Adapted from Assessment of Demand Response Potential for Hawaiian Electric, Hawai'i Electric Light and Maui Electric, Global Energy Partners, 2010

[46] The study considered ancillary services to represent "Fast DR" which requires a response time of 10 minutes or less within the event notification. Most ancillary services in Hawai'i require response speeds on the order of less than two minutes.

integration of DR resources into the market. GIWH DR programs are an example of how smart grid applications are utilized for effective integration of DR resources to provide grid services with minimal effects on customer comfort. Electric Vehicles (EVs) have also been shown to create ancillary service opportunities via DR.[47]

In conclusion, the 2010 DR Potential study serves as a foundation for assessing the DR opportunities on the Companies' systems; however, the recent developments discussed above must be taken into account to obtain a better estimate of the DR potential. The DR potential figures presented in Chapter 4 take these recent developments into account.

In the near term, the Companies plan to gain and apply additional knowledge by utilizing market mechanisms to attract and incentivize customers and demand-side aggregators to realize the actual cost-effective DR potential in the Companies' systems. While the Companies intend to engage in additional market research (ideally coordinated with Hawai'i Energy), the Companies are moving forward aggressively to implement the IDRRP with expanded and new DR programs.

[47] Tomi, Jasna, and Willett Kempton. "Using fleets of electric-drive vehicles for grid support." Journal of Power Sources 168.2 (2007): 459-468.

4. Existing and Planned Demand Response Programs

To develop the IDRPP, the Companies reviewed existing DR and load management programs, looking for opportunities to modify and expand those programs, and developed new DR programs to meet the grid services requirements of the Companies' systems.

PORTFOLIO APPROACH

Creating a comprehensive IDRPP requires an evaluation of the current state, a vision of the desired future state, and an execution plan to move from one to the next. At present, each operating utility has load management programs in the form of rate schedules, but only Hawaiian Electric has made any significant progress on traditional DR programs. The programs in place on O'ahu have successfully addressed capacity needs, but to date have not been used to provide ancillary services.

The current state of DR implementation on O'ahu and the future state of DR implementation envisioned for all islands is illustrated in Figure 12. The IDRPP would be a portfolio of individual DR programs that collectively address the Companies' grid service requirements. Across the programs, major delivery strategies have been identified such as direct load control products (where the Companies remotely shut down or cycle a customer's electrical equipment, including air conditioners, water heaters, lighting, etc.) and flexible products (where the Companies can use programs to meet more ancillary service-focused requirements such as regulating reserve).

The IDRPP would involve:

- Greater quantities and more effective use of existing direct load control programs like the RDLC,[48]
- Faster and more flexible ancillary service-focused programs, and
- Time-based pricing programs that shift customer demand from peak periods to overnight or midday periods.

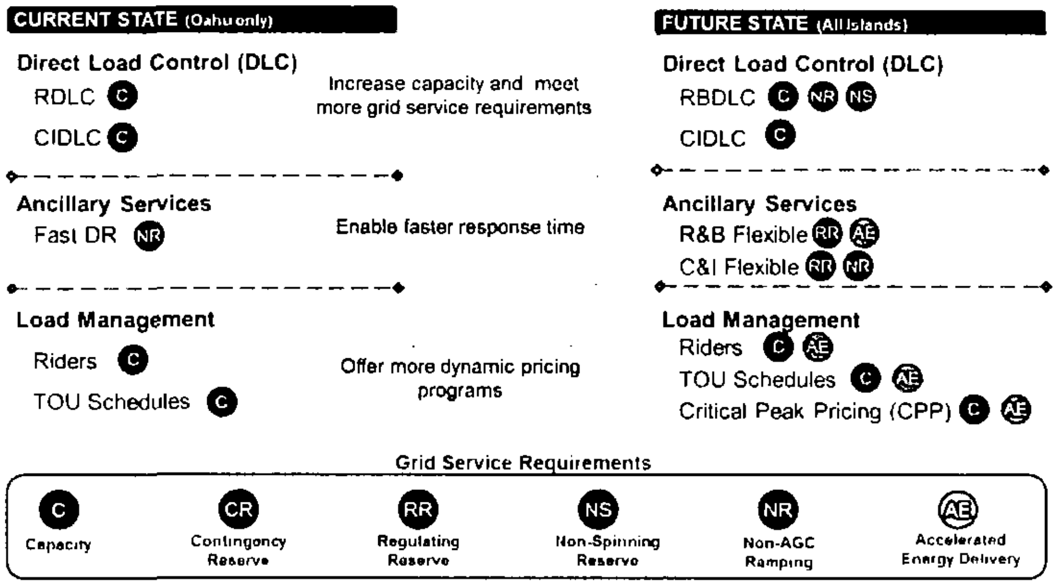

Figure 12. Current and Future State of Demand Response Programs

ASSESSMENT OF EXISTING DR PROGRAMS

Review of Existing DR Programs

Hawaiian Electric achieves significant capacity benefits each year through its residential and C&I direct load control programs. In addition, all Companies' systems have load management programs in the form of Rider programs and time-of-use based rate schedules.

The existing DR programs on O'ahu represent a solid foundation from which to build the portfolio. However, to maximize their value and to set a standard for effective DR programs on other islands will require adjustments, including: program expansion for

[48] This program will be combined with the Small Business Direct Load Control program and will be named Residential and Small Business Direct Load Control in the integrated DR portfolio.

the RDLC on O'ahu, program reconstitution and repricing for the CIDLC on O'ahu and the Fast DR pilot on O'ahu and Maui, and adjustment of program details to meet current and future conditions (redefining of Rider M peak hours).

A summary of attributes of the existing DR programs across the Companies is provided in Table 13.

	RDLC	CIDLC	Fast DR (Hawaiian Electric)	Fast DR (Maui Electric)
Target Customers	• Residential	• Commercial and Industrial	• Commercial and Industrial	• Commercial and Industrial
Participation (load impacts in MW are shown at customer level)	• 32,350 WH and 3,750 AC as end of 2013 • 14.8 MW	• 38 large C&I, and 160 small and medium business as end of 2013 • 12.8 MW	• 38 enrolled customers as of March 2014 • 6.1 MW	• 4 enrolled customers as of March 2014 • 0.2 MW
Participation Conditions	• Electric water heater • Central air conditioning • Load control receiver or PCT	• Large C&I with non-critical or generator backed loads, with minimum 50 kW of control • Small C&I with electric water heating and central air conditioning	• Min 50kW controlled • 10min or less response • Max 2 hr duration	• Min 50kW controlled • 10min or less response • Max 2 hr duration
Incentives for Participation	• $3/WH-mo • $5/AC-mo • No variable payment required per event	CIDLC • $10/kW-mo for auto load shed • $5/kW-mo + $0.5/kWh for manual dispatch SBDLC: • $5/WH-mo • $5/AC-mo • $8/other-mo	• Tiered incentive ranging from $5/kW-mo to $10/kW-mo • Also technology incentive ranging from from $300/kW-yr for semi-auto control, to $600/kW-yr for auto load control	• $5/kW-mo and $0.5/kWh after the first 15 hours of curtailment
Availability	• 24 hrs/day, 365 days/yr • No notification • Under-frequency, reliability and economic dispatch	• 24 hrs/day, 365 days/yr • 1-hr advance notice • Up to 300 hrs/yr • Under-frequency and reliability dispatch	• For $5/kW-mo, 40 hrs/yr, up to 40 events • For $10/kW-mo, 80 hrs/yr, up to 80 events	• 40 hrs/yr, up to 40 events
Technology	• One-way Paging Load Control Receiver	• One-way Paging Load Control Receiver	• Two-way comms • AutoDR / Aggregator	• Two-way comms • AutoDR /Aggregator

Table 13. Attributes of existing DR programs

Existing DR Program Events — 2013

Table 14 summarizes the use of existing programs during calendar year 2013, in terms of cumulative load impact, number of events, and total duration of the program. On O'ahu, the RDLC program has been used more frequently than the CIDLC program, in part because the RDLC lacks the variable payment that comes with the CIDLC, and also because the RDLC has a more favorable dispatch notification requirement (from the system operator's perspective) than does the CIDLC program (the RDLC program requires no notice to the customer, while the CIDLC requires one hour notice to the customer).

Program	Participating Load (customer level impact)[1] (MW)	2013 Load Impact Estimate (MW)	2013 number of events and tests	2013 Duration
RDLC	14.8[2]	7.2[3,4]	58 events + 19 tests	75 hr 30 min
CIDLC	12.8	12.3[3]	3 events + 2 tests	1 hr 13 min
Fast DR (Hawaiian Electric)	6.1	0.7[3]	54 tests	33 hr 15 min
Fast DR (Maui Electric)	0.2	0.15[5]	29 tests	19 hr 30 min

[1] Customer-level impact Impacts at gross generation level are multiplied by 88 83% to get the equivalent impacts at the customer level

[2] Derived using assumptions and methodologies presented in the 2011 EnergyScout Impact Evaluation Report, filed on March 31, 2011 in Docket No. 2007-0341

[3] Based on the average load shed estimate of the 2013 RDLC water heater events No RDLC A/C event took place in 2013

[4] Evening peak average load impact was 9.4 MW.

[5] Cumulative load impact of enabled load. Maui Electric enabled three of its four enrolled customers in 2013.

Table 14. Summary of 2013 DR program events

The RDLC water heater DR program was the most frequently used program with an average load shed of 7.2 MW[49] and with longest hours of operation – more than 75 hours throughout the year. Out of the 58 events that took place, 11 were under-frequency events, 18 were reliability events, and 29 were economic dispatch events, where the water heaters were called to avoid having to start a new cycling or peaking unit. The system operator typically dispatches the RDLC water heater program for one hour at a time, often to offset the need to commit a cycling or peaking unit to meet spinning reserve requirements during the evening peak. The RDLC program can be run for longer periods if needed, but Hawaiian Electric has determined that events of longer than one hour may begin to impact the customer (in the form of cold water) and could thus result in in increased program attrition. Current program attrition is primarily the result of customers transitioning to solar water heating.

The CIDLC DR program, by contrast, was called only three times for under-frequency load shedding purposes in 2013, and even though the average load shed was relatively high, it was utilized for less than 15 minutes in total, not including the duration of test events. One of the reasons for this low utilization rate is the one-hour advance notice that Hawaiian Electric is required to give prior to an event. In addition, the program has a payment of $0.50 per kWh of energy curtailed, which makes the CIDLC program less cost effective than any oil-fired unit, and thus not a candidate for regular dispatch. As proposed under the IDRPP, the CIDLC program would be revised to remove the advance notice requirement.

[49] Average load shed during different periods of the day varied. For example, between 6 pm and 9 pm average load shed was estimated as 9.4 MW.

During 2013, the Fast DR pilot program was tested 54 times on O'ahu and 29 times on Maui with relatively short duration events. The Fast DR pilot program was not called for regular events during 2013.

Cost-Effectiveness of Existing DR Programs

Another critical element in assessing the performance of the programs is their cost-effectiveness. Starting from the cost side of that equation, the total program costs incurred in 2013, and the projected 2014 budget for each are summarized in Table 15. For the Fast DR pilot, administration is the major cost-driver. In the case of the mature DLC programs, incentives are a majority of the cost.

Program	Program Costs ($)		2013 Total Cost ($)	2014 Total Budget ($)	Approx. 2013 Cost per kW[3] ($/kW-yr)
	Incentives[1]	Administration Costs[2]			
RDLC	1,400,603	688,623	2,089,226	2,681,000	200
CIDLC	2,433,727	410,346	2,844,073	4,857,000	250
Fast DR (Hawaiian Electric)	70,807	1,157,950	1,228,757	2,220,418	N/A[4]
Fast DR (Maui Electric)	3,115	40,629	43,744	89,025	N/A[4]
Total	3,908,252	2,297,548	6,205,800	9,847,443	

[1] Payments made to the program participants
[2] Administration costs include materials, outside services, labor, transportation, other, etc.
[3] For RDLC, based on the evening peak load reduction impact. For CIDLC, based on the average load impact of the three events throughout the year.
[4] All Fast DR events were tests, therefore no cost calculation was made

Table 15. Cost evaluation of existing DR programs

The RDLC and CIDLC programs were primarily developed to defer the need for new capacity. The RDLC is cost effective as a capacity deferral resource based on the installed capacity costs for new peaking generation on O'ahu, where power generation, construction labor and materials costs are much higher than those on mainland. For example, assuming an installed capacity cost of $1,750 per KW for new peaking capacity and annual carrying costs of 12% to 15%, the capacity value of RDLC is in the range of $210 to $260/kW-year, which is greater than the observed 2013 RDLC cost of approximately $200/kW.

The RDLC program also provides economic dispatch benefits. The RDLC can be economically dispatched when the system operator determines it is less expensive to call the RDLC program load than it is to start a peaking or cycling unit. For example, the RDLC water heater program might be called just before the evening peak, resulting in approximately 10 MW of load reduction, instead of starting the next generating unit in the merit order (i.e. the next most expensive variable cost generating unit). The avoidance of starting the next unit (which is at a higher cost that the marginal cost of the last committed generating unit then operating) avoids fuel use and results in savings to customers. When the same water heater load returns at the end of the event -- when system load is falling -- it can be met by a lower heat rate unit and thus reduces the system's fuel use, relative to a system where the RDLC does not exists.

The existing CIDLC program requires a one-hour notice to the customer prior to any manual events, and thus offers less flexibility (and value) to the system operator as currently constituted. With an observed cost of approximately $250 per kW of capacity interrupted in 2013, the case for the CIDLC program is less clear, especially when compared to the RDLC. Total RDLC costs were almost 30% lower in 2013, driven by lower incentive costs. Even though the RDLC program was dispatched about 20 times more often than the CIDLC program , incentives paid to RDLC participants in 2013 totaled $1.4 million, or 40% lower than the incentives paid to CIDLC participants. However, administration costs for RDLC were 70% greater than CIDLC, which is not surprising given the much smaller amounts of DR capacity achieved per customer through residential programs relative to C&I programs.

Ability of Existing Demand Response Programs to Meet Grid Service Requirements

With the exception of RDLC, the current programs show limited capability to meet the Companies' current and anticipated grid service requirements, as illustrated in Table 16.

While all four programs are capable of providing capacity, and have been successfully used for this purpose over the past several years, they generally were not designed with other grid service requirements in mind. RDLC and CIDLC do provide under-frequency response capability, and as such can be utilized as contingency reserve resources serving as system protection resources. However, they do not respond fast enough to serve as primary protection resources, and thus cannot be substituted for spinning reserves under the Companies' contingency reserve requirement.[50] All of the DR programs except CIDLC can provide 10-minute and 30-minute non-spinning reserves; again the CIDLC's one-hour advance notice requirement is a limitation in this regard.

[50] Contingency reserves that cannot meet the 7 cycle operation requirement can be used for contingency reserves for the "kicker block" of contingency reserve requirements, provided such change in load is controllable within an accuracy of +/- 0.02 Hz, +/- 0.0167 cycles and be capable of providing response time from frequency trigger to load removal in adjustable increments of 0.5 seconds up to 30 seconds.

Grid Service Requirements	Current Demand Response Programs			
	RDLC	CIDLC	Fast DR (Hawaiian Electric)	Fast DR (Maui Electric)
Capacity	✔	✔	✔	✔
Regulating Reserve	✖	✖	✖	✖
Contingency Reserve*	✔	✔	✖	✖
Non-Spinning Reserve	✔	✖	✔	✔
Non-AGC Ramping	✔	✖	✖	✖
Accelerated Energy Delivery	✖	✖	✖	✖

* Under-frequency response provided by RDLC and CIDLC can provide system protection but is not fast enough to be substituted for spinning reserves under the Companies' contingency reserve requirement.

Table 16. Capability of existing programs relative to grid service requirements

DR Program Evaluation and Redesign Considerations

RDLC is cost effective and capable of meeting a wider range of grid service requirements going forward. Therefore the IDRPP contemplates expanding the RDLC program in the Hawaiian Electric system and launching the RDLC program in the Hawai'i Electric Light and Maui Electric systems. Hawaiian Electric also proposes to combine the Small Business Direct Load Control (SBDLC) program, which is currently administered under the CIDLC program, with the RDLC program. This may result in more effective program administration, because the SBDLC and RDLC programs have very similar characteristics due to the fact that they both predominately rely on electric water heaters and air conditioners as the end uses available for load reductions. The IDRPP provides for the two programs to be administered under a single program, called the Residential and Small Business Direct Load Control (RBDLC).

The CIDLC and Fast DR programs each have promising attributes, but need to be modified and reconstituted to provide a greater range of grid service requirements. CIDLC participants appear to be overcompensated, especially given the limited or non-existent need for additional capacity to meet system peaks and planning reserve margins on O'ahu. Thus the Companies propose to eliminate or substantially modify the CIDLC program. Notwithstanding the limited value of the existing CIDLC program, the CIDLC customer base may be valuable participants in other DR programs that could provide ancillary services.

The Fast DR program requires customer loads to respond in time frames ranging from one to 10 minutes. While this is a substantially faster response time than the CIDLC resources to which they were being compared when the pilot program was named, the Fast DR program response time is not fast enough to meet regulation reserve and contingency reserve requirements. In addition, with only 40 to 80 events per year that can be called under the Fast DR program, the Program would be unable to contribute to grid service requirements with any sustained regularity. Disaggregating the customer base and targeting the resources that are able to respond in less than two minutes for a new DR program or making one-minute response times compulsory in the Fast DR program would provide a DR resource that could provide non-AGC ramping, making such a program significantly more valuable to the Companies' systems relative to DR programs with longer response times.

Load Management Programs

In addition to the existing DR programs on O'ahu, the Companies have several load management programs that were designed to provide capacity services to the grid. These programs offer a certain degree of load control to the utilities when needed, while providing financial incentives to their participants. Some of these programs have been in operation for decades.

Rider M

Program Description

The Rider M program either incentivizes the customers to shift their demand to off-peak hours (Option A), or enables the Company to curtail the customer's demand at certain peak load periods (Option B). In return, the customers are able to reduce the demand charge portion of their monthly bill, and the Companies gain some level of control over load during the peak load periods.

Rider M is available to customers served under Schedules J, P and DS[51] whose maximum measured demand exceeds 100 or 300 kW, depending on the rate schedule. Rider M cannot be used in conjunction with Rider T, Rider I, Schedule U, Schedule TOU-P, or Schedule TOU-J. The Companies have installed time-of-use meters to measure the customer's maximum kilowatt load during the time-of-day rating periods and curtailment periods.

Under Rider M, there are two options from which the customer can choose:

Option A - Off-peak Service:

Option A incentivizes the customers to shift their demand to off-peak hours, because demand during the off-peak hours does not affect the billing demand determination under the rate schedule applicable to the customer. Instead, an excess off-peak charge of $2.00/kW-month (Hawaiian Electric) or $1.00/kW-month (Hawai'i Electric Light and

[51] Hawaiian Electric only.

Maui Electric) is added to the regular rate schedule for each kilowatt that the maximum off-peak demand exceeds the maximum demand during the on-peak period (see Appendix C for regular rate schedules). For example, if an O'ahu customer's maximum on-peak demand for a given month is 350 kW and the customer's maximum off-peak demand is 400 kW, the customer is deemed to have 50 KW of "excess" off-peak demand (400 KW – 350 KW) and will pay a $100 off-peak charge ($2.00/KW-month, multiplied by 50 KW) in addition to a demand charge based on the (lower) on-peak demand. At present, the Rider M defined on-peak period is from 7 am to 9 pm and the off-peak period is from 9 pm to 7 am. Thus, the existing Option A incentivizes the shifting of load from the daytime hours to the overnight hours.

Option B – Curtailable Service:

Under Option B, the customer contractually commits the load they are willing to curtail during the specified curtailment hours. There are minimum limits on the amount of curtailable load.[52] The actual curtailed load is determined monthly as the difference between the maximum demand in kilowatts outside of the curtailment hours and the maximum demand in kilowatts during the curtailment hours, but not exceeding the curtailable kilowatt load specified in the customer's contract. There are two curtailment period options to choose from, and the customer's decision regarding these curtailment periods impacts the benefit received from the program:

- Choosing a fixed curtailment period throughout the year between 5 pm and 9 pm, Monday through Friday reduces the normal billing demand by 75% of the curtailed kilowatt demand.
- Choosing two consecutive hours as specified by the Companies reduces the normal billing demand by 40% of the curtailed kilowatt demand.

Program Evaluation and Redesign Considerations

At the end of 2013, there were 26 Rider M contracts for Hawaiian Electric (all under Option-B), 33 for Hawai'i Electric Light, and 10 for Maui Electric.[53] On Maui, approximately 2,800 kW in evening peak reduction was achieved in 2012 through the Rider M contracts. On Hawai'i, this figure was 5,600 kW.[54]

Based on partial Hawai'i Electric Light data analyzed for a single large customer, shifting one kW away from the evening peak period costs approximately $65 per year,[55] a highly

[52] At least 50 horsepower for motor loads served under Schedule J, and 150 horsepower for motor loads served under Schedule DS, P, or 50 and 150 kW for other than motor loads, respectively.

[53] 9 in the Maui Division and one in the Moloka'i division.

[54] This estimate includes Schedule U customers' load reduction impact.

[55] Based on the annual financial incentives given to a single large customer's and average peak load reduction achieved by the same customer.

cost-effective option compared to the cost of installing new capacity with a revenue requirement exceeding $200 per year. However, relative to the marginal cost to serve load (which may be a more appropriate comparison on Hawai'i where capacity is not required in the near term), the program's value in the Hawai'i Electric Light system is less clear.

The Rider M program would benefit from an adjustment to its off-peak designations. The program was designed when the Companies did not have low demand during the midday period due to distributed solar generation. Currently the on-peak period is between 7 am and 9 pm under Option A, and therefore customers receive benefits when they shift their demand away from any period within this window. The actual "on-peak" period has changed with the growth of solar distributed generation from the actual on-peak period when the Rider M program was designed. Accordingly, the on- and off-peak designations need to be reset to match the needs of each grid, so that customers are incentivized to shift load to the midday period to "fill the Duck's belly," a need that will also be addressed by additional time-based pricing DR programs. On the Maui Electric system, shifting load to overnight periods, as well as to midday periods, is an appropriate objective in order to minimize wind curtailment.

Rider I

Program Description

This rider is based on an Interruptible Contract Service where, for Hawaiian Electric demand of 100 kW or greater, and for Hawai'i Electric Light and Maui Electric demand of 500 kW or greater, is subject to interruption by the Companies under the terms specified in the contract agreement. The Rider I contract duration is at least five years. Rider I has been closed to new customers since February 2011 at Hawaiian Electric. In return for providing interruptible demand, demand charges of the customers registered under this rider are reduced as set forth in a contract between the customer and the utility and approved by the Commission.

Program Evaluation and Redesign Considerations

As of November 2012, Hawaiian Electric had four customers registered under Rider I, totaling 3 MW of interruptible load. Rider I loads will be evaluated for potential transfer to other DR programs.

Rider T

Program Description

This rider is available to customers served under schedules J, P, or DS[56], and cannot be used in conjunction with Rider M, Rider I[57], Schedule U[58], Schedule TOU-J, or Schedule TOU-P[59]. The Rider T on-peak period is defined as 7 am to 9 pm. There is a $10/month time-of-day metering charge, which is applicable to Rider T customers across the three utilities. At Hawaiian Electric and Maui Electric, customers are given 3 cents credit for each kilowatt-hour they consume during off-peak hours, and charged 2 cents extra for each kilowatt-hour consumed during on-peak hours. At Hawai'i Electric Light, the off-peak credit is 3.15 cents per kWh and the on-peak surcharge is 2.50 cents per kWh.

Program Evaluation and Redesign Considerations

As of the end of 2013, there were 25 Rider T contracts at Hawaiian Electric and 36 Rider T contracts at Maui Electric. Similar to Rider M, this program will benefit from a redesign of on- and off-peak time designations and perhaps adjustments to the magnitudes of the incentives to encourage customers to shift part of their load to midday periods.

Schedule U

Program Description

Schedule U is available to the customers of Hawaiian Electric and Hawai'i Electric Light only, and applies to general light and/or power loads equal to or greater than 300 kW per month for Hawaiian Electric, and equal to or greater than 25 kW for Hawai'i Electric Light, supplied and metered at a single voltage and delivery point. Schedule U cannot be used in conjunction with Riders M, T, or I, or Schedules TOU-J and TOU-P.[60] On-peak and off-peak periods are defined similarly to the riders introduced earlier. However, Hawaiian Electric also has a "priority peak" period which is 5 pm to 9 pm Monday through Friday, and "mid-peak" period, which is all the on-peak hours outside of priority peak hours. At both utilities, in addition to a fixed per month charge, pricing for demand and energy is adjusted such that customers are incentivized to consume less during peak time hours.

[56] Hawaiian Electric only.
[57] Hawaiian Electric and Hawai'i Electric Light only.
[58] Hawaiian Electric and Hawai'i Electric Light only.
[59] Maui Electric and Hawai'i Electric Light only.
[60] Restriction on TOU-P applies to Maui Electric and Hawai'i Electric Light only.

Program Evaluation and Redesign Considerations

On/off peak, priority peak and mid-peak periods are proposed to be re-defined in order to more effectively shift load to desired periods during the day. Hawaiian Electric's Rider programs already dis-incentivize evening demand through higher surcharges during priority peak period; however there is no incentive provided for shifting load to the midday period.

Time-of-Use Schedules

All three utilities have TOU schedules specific to each customer class.[61] Program design parameters such as pricing periods or pricing levels vary across companies and schedules. Generally speaking, these TOU schedules include a priority peak period during which customers pay higher demand and energy charges. In some cases, there are also different pricing levels for customers whose consumption exceeds a certain threshold per month.

In addition to the programs summarized above, the Companies have pilot schedules for commercial and residential EV charging. In principle, these are TOU schedules specifically designed based on EV charging patterns with the objective of providing maximum benefit to customers while reducing peak time demand on the grid. The Companies are in the process of evaluating the results obtained from these pilot schedules.

All of the TOU schedules in operation are static, although with the rollout of AMI, the Companies are planning to add dynamic, event-driven pricing programs into their DR portfolio, such as Critical Peak Pricing (CPP).

PLANNED PROGRAM PORTFOLIO

The Companies are committed to finding the most cost effective, reliable load resources possible to provide both capacity and ancillary services. This will be a driving component of the envisioned future state on O'ahu and of the emerging portfolios serving Maui, Hawai'i, Lana'i, and Moloka'i.

[61] All the three utilities have TOU-R, TOU-G, TOU-J. Hawai'i Electric Light and Maui Electric also have TOU-P.

Program Screening Criteria

Following the approach outlined in Chapter 1 of this report, new DR program specifications were developed based on the grid service requirements, the suitability of end uses to meet the grid service requirements, and estimates of customer load available for participation in DR programs.

Another DR program design consideration is the potential for interactions among DR programs. If many of the Companies' larger customers are on an existing interruptible tariff, then introducing a DR program that appeals to those customers may simply result in a shift of DR resources rather than an expansion of the total pool of DR resources available to meet grid service requirements. In order to ensure that the integrated DR portfolio design is holistic and effective, the following screening criteria were applied to the program and portfolio design:

- Do we already have a program providing or partially providing the needed grid service requirements? If so, better to modify the existing program or create a new one?
- Is the DR program sufficiently customer-focused? From the customers' perspective, DR programs need to offer real benefits and value to the customer.
- Is the DR program cost-effective from the standpoint of all customers? From a total resource perspective, the DR program benefits must be greater than the program costs. Moreover, the cost of the DR Program must be competitive with the interchangeable resources (for example, firm generation units, energy storage) that could meet the same grid services requirements.
- Are DR program opportunities equitably distributed across the customer base? Over time, DR programs will be offered to all classes of customers in all of the Companies' service territories.

DR Portfolio Overview

The proposed DR portfolio would be comprised of several distinct DR programs. In building the DR portfolio, the Companies grouped the candidate DR programs into seven main categories, based on the major attributes of program design, such as a targeted grid service requirement, customer class and type of end use to be utilized for demand response. These seven categories are:

1. Residential and Small Business Direct Load Control (RBDLC)
2. Residential and Small Business Flexible (R&B Flexible)
3. Commercial & Industrial Direct Load Control (CIDLC)

4. Commercial & Industrial Flexible (C&I Flexible)

5. Water Pumping

6. Customer Firm Generation

7. Dynamic and Critical Peak Pricing

Each DR program would be designed to provide one or more specific grid service requirements. Furthermore, each DR program utilizes one or more types of customer end uses. Therefore, it is possible that one grid service requirement could be satisfied by multiple resources, or conversely, one resource could be utilized to meet multiple grid service requirements (though generally not concurrently).

The Companies used the best available information regarding the market and existing technology, in addition to the program screening criteria discussed in the previous section, to assign load resources to specific DR programs in the IDRPP. In lieu of additional detailed studies, the Companies will defer to experience gained through the modification of existing DR programs and the introduction of new DR programs to customers. As actual experience reveals the strengths and weaknesses of given DR programs to the Companies, their customers, and the Commission, the DR programs will be adjusted as appropriate. The mapping of targeted end uses to programs, and the grid services satisfied under each program (as envisioned by the Companies at the time of writing this report) are shown in Table 17.

Program	Grid Service Requirement	Resource
RBDLC	Capacity	Water Heaters, central A/C
	Non-AGC Ramping	Water Heaters, central A/C
	Non Spinning Reserve	Water Heaters, central A/C
R&B Flexible	Regulating Reserve	GIWH, central A/C
	Accelerated Energy Delivery	GIWH
CIDLC	Capacity	C&I Curtailable
C&I Flexible	Regulating Reserve	Central A/C, Ventilation, Refrigeration
	Non-AGC Ramping	Central A/C, Ventilation, Refrigeration, Lighting
Water Pumping	Regulating Reserve	Pumps
	Non-AGC Ramping	Pumps
Customer Firm Generation	Capacity	Generators
Dynamic and Critical Peak Pricing	Capacity	Unspecified Customer Load
	Accelerated Energy Delivery	Unspecified Customer Load

Table 17. Programs, grid services and load resources considered in the integrated DR portfolio

In Table 18 through Table 24 more detailed overviews of each proposed DR program in the proposed DR portfolio are provided. The details address the following components of each of the DR programs:

- *Program Objectives:* An overview of the grid service requirements the specific DR program is designed to satisfy.
- *Program Description:* A descriptive overview of the intent of the program.
- *Program Compensation:* Level and structure of compensation to customers registered in the program.
- *Performance Measurement:* Measurement and verification method to evaluate the performance of the program.
- *Program Availability:* The required availability of load resources across defined time periods (days, month, year) enrolled in the program and the notification requirement for an event.
- *Response Duration:* The time period for which the load resource must be capable of being curtailed during a called event.
- *Response Speed:* Required response speed to effectively dispatch the DR resource on demand.
- *Program Penalties:* The loss of compensation and/or additional charges to the customer for failure to perform in accordance with the terms of the program.
- *Program Administration:* Parties involved in administration of the program.
- *Technical Requirements:* Technology requirements and limitations associated with each program.

Residential &Small Business Direct Load Control (RBDLC)						
Grid Service Requirements	Capacity	Regulating Reserve	Contingency Reserve	Non-AGC Ramping	Non-Spinning Reserve	Accelerated Energy Delivery
	●			●	●	
Program Description	The RBDLC program is a continuation and expansion of the existing RDLC and Small Business DLC programs and will continue to provide customers with the opportunity to participate in an interruptible load program for electric water heaters, central A/Cs and other specific end uses. The program will build on the customers that are currently enrolled in the program.					
Program Compensation	Availability payment as determined in the annual auction ($/kW-yr)					
Performance Measurement	Difference between pre- and post-event load					
Cost per Event	None					
Program Availability	24 hrs/day, 365 days/yr, no notification					
Response Speed	Response speed will vary depending on the grid requirement that system operators are trying to satisfy and will range from <2min to <30 min					
Program Penalties	Loss of incentive payments and/or system tariff penalty payments					
Program Administration	Utility and/or third party DR provider					
Potential Load Resources	Electric water heater, central A/C and other equipment as approved by the utility					
Technical Requirements	Current technology is largely a one-way paging system , but will need to update load control switches and roll out an improved two way communications network to improve feedback on customer response to events; and to provide the ability to check individual device status and reachability. As AMI is implemented, these units may migrate to a ZigBee control protocol (switches are dual mode, i.e., both VHF paging and ZigBee). Demand Response Management System (DRMS) will also be required.					

Table 18. Residential and Small Business Direct Load Control program overview

Residential & Small Business Flexible (R&B Flexible)						
Grid Service Requirements	Capacity	Regulating Reserve	Contingency Reserve	Non-AGC Ramping	Non-Spinning Reserve	Accelerated Energy Delivery
		●				●
Program Description	This program provides residential and small business customers that can meet telemetry and other qualification requirements with an opportunity to provide ancillary services. Devices that can provide load control & storage features over various timeframes will be targeted.					
Program Compensation	Availability payment as determined in the annual auction ($/kW-yr)					
Performance Measurement	Difference between pre- and post-event load					
Cost per Event	None					
Program Availability	Continuous					
Response Speed	For Regulating Reserve within 2 seconds of receiving the AGC signal, for Accelerated Energy Delivery no specific speed requirement					
Program Penalties	Loss of incentive payments and/or system tariff penalty payments					
Program Administration	Utility and/or third party DR provider					
Potential Load Resources	GIWH, central A/C and other equipment as approved by the utility					
Technical Requirements	Aggregating load control modules and next-gen variable capacity water heaters, two-way comms AutoDR					

Table 19. Residential and Small Business Flexible program overview

Commercial & Industrial Direct Load Control (CIDLC)						
Grid Service Requirements	Capacity	Regulating Reserve	Contingency Reserve	Non-AGC Ramping	Non-Spinning Reserve	Accelerated Energy Delivery
	●					

Program Description	CIDLC program is available to commercial and industrial customers with non-critical or generator-backed loads that can be disconnected by the Companies. Operation of DLC typically occurs during times of high peak demand.
Program Compensation	Availability payment as determined in the annual auction ($/kW-yr), and energy payment ($/kWh)
Performance Measurement	Difference between pre- and post-event load
Cost per Event	$0.50 per kWh
Program Availability	Up to 300 hours per year
Response Speed	Concurrent with event
Program Penalties	Loss of incentive payments and/or system tariff penalty payments
Program Administration	Utility and/or third party DR provider
Potential Load Resources	Non-critical or generator-backed customer load
Technical Requirements	Load Control Switches, PCTs, real-time performance transparency, two-way comms AutoDR

Table 20. Commercial & Industrial Direct Load program overview

Commercial & Industrial Flexible (C&I Flexible)						
Grid Service Requirements	Capacity	Regulating Reserve	Contingency Reserve	Non-AGC Ramping	Non-Spinning Reserve	Accelerated Energy Delivery
		●		●		

Program Description	This program provides commercial and industrial customers that can meet telemetry and other qualification requirements with an opportunity to provide ancillary services. Devices that can provide load control & storage features over various timeframes will be targeted.
Program Compensation	Availability payment as determined in the annual auction ($/kW-yr)
Performance Measurement	Difference between pre- and post-event load
Cost per Event	None
Program Availability	Continuous
Response Speed	For Regulating Reserve within 2 seconds of receiving the AGC signal, for Non-AGC Ramping less than 2 minutes
Program Penalties	Loss of incentive payments and/or system tariff penalty payments
Program Administration	Utility and/or third party DR provider
Potential Load Resources	Central A/C, refrigeration, ventilation, lighting
Technical Requirements	Real-time performance transparency, two-way comms AutoDR

Table 21. Commercial & Industrial Flexible program overview

Water Pumping						
Grid Service Requirements	Capacity	Regulating Reserve	Contingency Reserve	Non-AGC Ramping	Non-Spinning Reserve	Accelerated Energy Delivery
		●		●		
Program Description	This program targets variable speed pumping loads at water facilities. Water pumping loads can be dynamically controlled using variable frequency drives, and therefore provide benefit to grid operations in balancing supply and demand.					
Program Compensation	Availability payment as determined in the annual auction ($/kW-yr)					
Performance Measurement	Difference between pre- and post-event load					
Cost per Event	None					
Program Availability	Continuous					
Response Speed	For Regulating Reserve within 2 seconds of receiving the AGC signal, for Non-AGC Ramping less than 2 minutes					
Program Penalties	Loss of incentive payments and/or system tariff penalty payments					
Program Administration	Utility and/or third party DR provider					
Potential Load Resources	Commercial and municipal water and wastewater pumping					
Technical Requirements	Variable Speed Devices, real-time performance transparency, two-way comms AutoDR					

Table 22. Water Pumping program overview

Customer Firm Generation						
Grid Service Requirements	Capacity	Regulating Reserve	Contingency Reserve	Non-AGC Ramping	Non-Spinning Reserve	Accelerated Energy Delivery
	●					
Program Description	This program is designed for commercial and industrial customers with diesel generators on site that can be dispatched upon system operator's signal. The generators will require monitoring equipment to track usage of program participation, testing and EPA compliance.					
Program Compensation	Availability payment as determined in the annual auction ($/kW-yr), and energy payment ($/kWh)					
Performance Measurement	Amount of self-supply and/or exported power to the grid provided during the event					
Cost per Event	$0.50 per kWh					
Program Availability	100 hours per year					
Response Speed	Minutes					
Program Penalties	Loss of incentive payments and/or system tariff penalty payments					
Program Administration	Utility					
Potential Load Resources	Customer-sited diesel generators					
Technical Requirements	Real-time performance transparency, two-way comms AutoDR					

Table 23. Customer Firm Generation program overview

Dynamic and Critical Peak Pricing (CPP)						
Grid Service Requirements	Capacity	Regulating Reserve	Contingency Reserve	Non-AGC Ramping	Non-Spinning Reserve	Accelerated Energy Delivery
	●					●
Program Description	This program is designed to change customer behavior through pricing signals. TOU is a static program where pricing schedules are set for the day, while CPP is a dynamic program where customers are sent pricing signals prior to a high demand projection					
Program Compensation	Customers are compensated indirectly through lower prices at certain hours during the day.					
Performance Measurement	-					
Cost per Event	-					
Program Availability	-					
Response Duration	-					
Response Speed	Minutes or hours					
Program Penalties	None					
Program Administration	Utility					
Potential Load Resources	Unspecified customer load					
Technical Requirements	Real-time performance transparency, two-way comms AutoDR					

Table 24. Dynamic Pricing and CPP programs overview

Dynamic and Critical Peak Pricing (CPP) Programs

Provided that the necessary metering and communications infrastructure is in place, Dynamic and CPP programs can be used to shift load from on-peak to off-peak hours by providing a direct and measurable financial incentive to customers, thereby facilitating a behavioral change. However, customer response is not guaranteed; a customer may enthusiastically reduce consumption during peak hours almost all the time, but the fact that they may not choose to do so on the hottest days of the year, for example, makes the amount of system peak reduction harder to count on. Finally, it has been shown that unless these programs are mandatory or default opt-in, participation rates remain low.[62]

Estimation of Demand Response to Dynamic and CPP Programs on the Islands

The Companies have concluded that load shifting and energy savings could be realized through the implementation of dynamic pricing and voluntary CPP for residential (Schedule R) customers, general service non-demand (Schedule G) customers, and general service demand (Schedule J) customers. These considerations would be based upon typical weekday and weekend load profiles for each of the customer classes and

[62] Dynamic Pricing: The Facts are in, Part II, accessed online at http://www.intelligentutility.com/article/12/08/dynamic-pricing-facts-are-part-ii on July 7, 2014.

would be constructed based upon the application of demand elasticity adjustments to assumed time of use rate structures. The rate structures, in turn, could be designed to be revenue neutral based upon current rates, and assuming no overall change in consumption.

For example, and also for planning purposes, the approach has been applied on a preliminary basis to develop estimates of load shifting by island, and is presented in Figure 13 through Figure 15. A simplified two-period pricing structure has been analyzed in which 4 pm to 11 pm is on-peak, and off-peak price is assumed to be 75% of the current average prices. The load changes have been subtracted from the overall system load shape to develop estimates of the change in the total system load shape. "Weekday-Before" and "Weekend-Before" refer to the load shape before dynamic pricing or CPP program implementation; "Weekday-After" and "Weekend-After" refer to the modified load shape after the implementation of dynamic pricing and CPP programs. The average load shapes for June 2020 are shown for illustrative purposes.

Hawaiian Electric's projected load shape suggests that dynamic pricing and CPP may be able to reduce the weekday on-peak load by almost 80 MW at times, and distribute the load to off-peak hours of the weekdays. The maximum load reduction is approximately 8% of the weekday peak demand (as measuring without such pricing programs in effect). Additionally, because part of the demand is shifted to off-peak hours of the day, the "filling-the-valley" and curtailment reduction goals may be achieved simultaneously. Similarly, on-peak demand for the weekends can be reduced, albeit by a smaller magnitude, estimated at around 32 MW at most. This represents roughly 4% of the weekend peak demand in the absence of pricing programs.

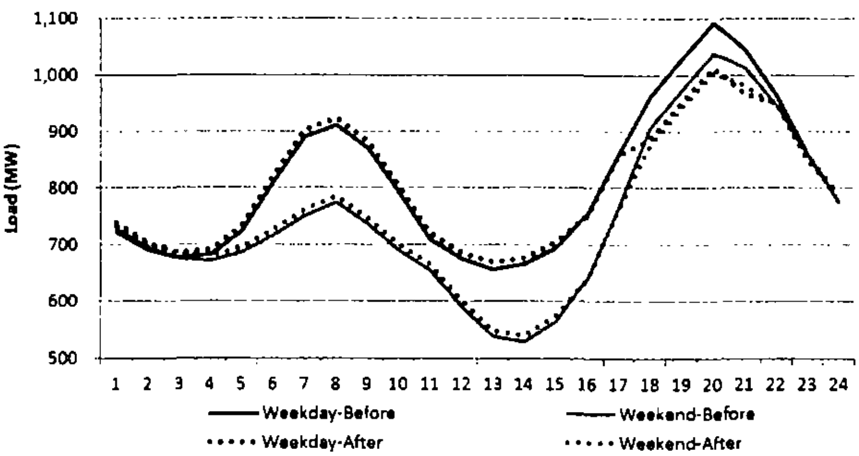

Figure 13. Hawaiian Electric system demand, June 2020

Due to smaller system size, the dynamic pricing and CPP impacts on the load shape of Hawai'i Electric Light and Maui Electric are less pronounced in terms of total MWs shifted. However, achieved load reduction as a percentage of peak demand is very similar to that of Hawaiian Electric. Results show that weekday on-peak demand can be reduced by 8% at Hawai'i Electric Light and 4% at Maui Electric. Weekend peak load reduction impacts are almost as high as weekday reduction impacts, in contrast to relatively lower weekend peak load reduction projected for Hawaiian Electric.

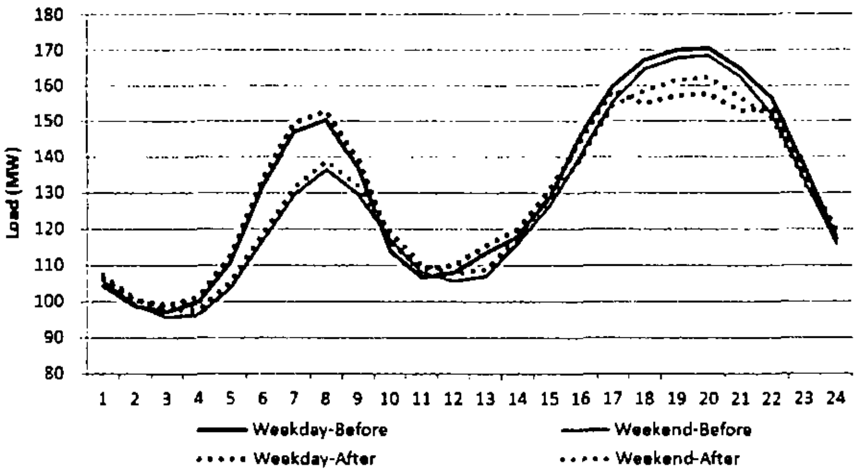

Figure 14. Hawai'i Electric Light system demand, June 2020

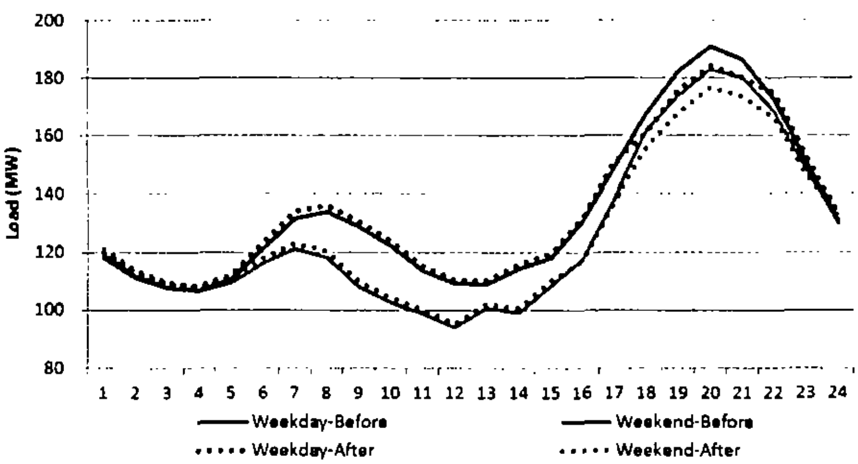

Figure 15. Maui Electric system demand, June 2020

RESOURCE POTENTIAL PROJECTION BY PROGRAM

The Companies assessed the DR potential projection by system based on the latest available information regarding the types of resources likely to be enrolled in DR programs to meet each grid service requirement, based on the findings from several of the sources discussed in Chapter 3. It should be noted that with the exception of the water companies and their pumping loads, the Companies may not target specific end use customers. Instead, the Companies intend to clearly state the specifications associated with each grid service requirement (for example required response time and duration) and would utilize market mechanisms to determine the customer segments and end use resources that can most cost effectively meet a given grid service requirement.

Although the Companies believe that the optimal end use resources for each grid service will be determined by the specific customers and third-party entities that are willing to utilize the market mechanisms, the mapping on Table 25 serves as an initial indication of potential target areas.

Resources	Capacity	Regulating Reserve	Contingency Reserve	Non-AGC Ramping	Non-Spinning Reserve	Accelerated Energy Delivery (Intraday)
Water Heater and A/C	✓	✓	✓	✓	✓	
C&I Curtailable	✓					
Ventilation		✓		✓		
Refrigeration		✓		✓		✓
Lighting				✓		
GIWH				✓		
Water Pumping		✓		✓		✓
Customer Generation	✓					✓
Electric Vehicles*	✓					✓

* Electric vehicles have not been included in current program projections but will be leveraged for DR as the market matures.

Table 25. Mapping resources to grid requirements

One important feature of these projections is that they start to level off in the future years. This is because peak load is projected to plateau and start declining after 2020 on all islands due to the effectiveness of energy efficiency programs (as previously discussed in Chapter 2, see Table 4, the peak demand by island).

The Companies will of course continue to aggressively pursue DR solutions in the years following 2020. Ongoing recruitment efforts and emerging technological advances are expected to keep DR participation from declining in the outer years, but current projections reflect the Companies' expectation that it will be difficult to continue growing program participation while sales and peak demand are declining. Therefore, depending on the resources used to fulfill a grid service requirement, potential estimates are assumed to stay flat either after 2020 or 2022, through 2034. The IDRPP will be constantly reevaluated in light of evolving technology and load, however, and the clear goal will be to continue growing the programs wherever cost effectively achievable.

The DR potential associated with each program and grid service requirement are summarized in Table 26 through Table 28. For more details on how the projections were estimated, see Appendix B. Appendix B also includes a preliminary assessment on the average hourly availability of the programs, recognizing that not all demand resources can provide services at full capacity in each hour of the day. For example due to the daily usage pattern of customers, electric water heaters do not draw power at all times during the day, and therefore the amount of DR potential expected from the RDLC program participants should be adjusted accordingly.

As Table 26, Table 27, and Table 28 show, DR potential projections are zero for to the contingency reserve service. This is because DR under frequency resources are not fast enough to serve as primary system protection resources, and may only be fast enough to contribute to the under frequency load shedding "kicker block." It should be noted that while the Companies are proceeding from a planning perspective as if DR will not reduce the need for contingency reserves on its systems, the Companies will actively pursue DR resources with this capability in the event that the market can provide them now or in the future.

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
RDLC	Capacity	10.0	30.4	33.3	33.3
	Contingency Reserve	0.0	0.0	0.0	0.0
	Non-AGC Ramping	10.0	30.4	33.3	33.3
	Non Spinning Reserve	10.0	30.4	33.3	33.3
[illegible]	Regulating Reserve	0.0	3.3	5.1	5.1
	Accelerated Energy Delivery	0.0	1.7	2.7	2.7
[illegible]	Capacity	10.0	23.8	25.4	25.4
	Contingency Reserve	0.0	0.0	0.0	0.0
[illegible]	Regulating Reserve	0.0	2.6	4.1	4.1
	Non-AGC Ramping	0.0	9.0	14.1	14.1
[illegible]	Regulating Reserve	0.0	1.2	1.9	1.9
Customer Firm Generation	Capacity	0.0	5.0	5.0	5.0
	[illegible]	26.0	70.2	82.4	82.4

** 2014 projection of 10 MW is based on the average load impact of the RDLC-WH program estimated for the evening hours of the 2013 events. No RDLC-AC event took place in 2013.*

*** Total number reflects the sum of the potential obtained from each load resource used to calculate these projections (which is not equal to the sum of the potentials identified under each grid service requirement in the table because of program overlap and the ability of some end use resources to meet multiple grid service requirements).*

Table 26. O'ahu programs with projections (MW)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	Capacity	0.0	4.9	6.0	6.0
	Contingency Reserve	0.0	0.0	0.0	0.0
	Non-AGC Ramping	0.0	4.9	6.0	6.0
	Non Spinning Reserve	0.0	4.9	6.0	6.0
[illegible]	Regulating Reserve	0.0	0.9	1.4	1.4
	Accelerated Energy Delivery	0.0	0.5	0.7	0.7
[illegible]	Capacity	0.0	1.8	2.2	2.2
	Contingency Reserve	0.0	0.0	0.0	0.0
[illegible]	Regulating Reserve	0.0	0.3	0.4	0.4
	Non-AGC Ramping	0.0	0.9	1.4	1.4
[illegible]	Regulating Reserve	0.0	0.1	0.2	0.2
[illegible]	Capacity	0.0	3.0	3.0	3.0
	[illegible]	0.0	11.1	13.6	13.6

** Total number reflects the sum of the potential obtained from each load resource used to calculate these projections (which is not equal to the sum of the potentials identified under each grid service requirement in the table because of program overlap and the ability of some end use resources to meet multiple grid service requirements).*

Table 27. Hawai'i programs with projections (MW)

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Maui	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	Capacity	0.0	5.7	7.1	7.1
	Contingency Reserve	0.0	0.0	0.0	0.0
	Non-AGC Ramping	0.0	5.7	7.1	7.1
	Non Spinning Reserve	0.0	5.7	7.1	7.1
[illegible]	Regulating Reserve	0.0	0.7	1.1	1.1
	Accelerated Energy Delivery	0.0	0.4	0.6	0.6
[illegible]	Capacity	0.2	2.5	3.0	3.0
	Contingency Reserve	0.0	0.0	0.0	0.0
[illegible]	Regulating Reserve	0.0	0.4	0.6	0.6
	Non-AGC Ramping	0.0	1.3	2.1	2.1
[illegible]	Regulating Reserve	0.0	0.2	0.3	0.3
[illegible]	Capacity	0.0	3.0	3.0	3.0
	[illegible]	0.2	13.1	16.1	16.1

** Total number reflects the sum of the potential obtained from each load resource used to calculate these projections (which is not equal to the sum of the potentials identified under each grid service requirement in the table because of program overlap and the ability of some end use resources to meet multiple grid service requirements).*

Table 28. Maui programs with projections (MW)

IDRPP FURTHER CONSIDERATIONS

IDRPP Expected Accomplishments by Program

Throughout the development of the IDRPP, the design of each DR Program has been driven by and crosschecked against, the guidelines and directives issued by the Commission.

The Companies adopt the objectives established by the Commission for the IDRP. The development and implementation of current and future DR programs will be aligned to support achievement of the stated objectives[63] while avoiding unnecessary costs and duplication of effort and maximizing benefits and DR capabilities.

[63] See Order pages 82-83 for stated objectives. "In this Policy Statement, the commission establishes the following as the stated objectives for current and future demand response programs to be developed and implemented by the HECO companies... "

Table 29 cross references each of the proposed programs against a list of IDRPP objectives, as identified and directed by the Commission in the Order. All programs meet multiple objectives, and all objectives are met by at least three of the seven programs.

All programs will compensate customers for their participation based on the value they add to the system, and between them the portfolio of individual programs will provide customers with a number of options for reducing their total electricity bills while providing the Companies with a range of options for providing a portion of the grid services necessary to reduce reliance on fossil fuel and increase the system's ability to take greatest advantage of the renewable energy resources.

Mapping Programs to Order Objectives	Residential & Small Business		Commercial & Industrial			Muni/C&I	Pricing
The commission established the following as the stated objectives for the current and future DR programs	DLC	Flexible	DLC	Flexible	Customer Generation	Water Companies*	Dynamic, CPP
1 DR programs should provide quantifiable benefits to ratepayers	H	H	H	H	H	H	H
2a. A reduction in total kWh consumed or a change in how kWhs are consumed that is beneficial to overall system operations	H	H	H	H		H	H
2b. A reduction in peak loads, and the deferral of new generation capacity	H		H		H	H	H
2c. Assistance in meeting PV and wind variability	M	H		H		H	
2d. A shift of a portion of system load to off-peak times (which may be mid-day in the near future for systems with high PV penetration) to among other things increase consumption of minimum load generation and to reduce curtailments of renewable generation		H		M		H	H
2e. Assistance in assuring the reliability of the system through among other things programs that permit fast response of short duration to meet contingency conditions prior to utility emergency diesel generations coming on line	M	H	M	H		H	
2f. A non-fossil fuel source of ancillary services, such as frequency management, up and down regulation, and dispatch able energy	M	H		H		H	
2g Customer benefits such as greater control over energy use and opportunities to lower electricity bills**	H	H	H	H	H	H	H
2h. A potential means for addressing greenhouse gas emissions standards established by the state of Hawaii and federal government.	H	M	H	M	H	H	H

H = Highly Satisfies M = Moderately Satisfies

* Water Companies category includes pumping as load resources and on-site emergency generators, both considered as potential DR options.

** All program participants (i.e. DR providers) will be paid for participating and will thus be able to lower their electricity bills; only pricing program participants would be viewed as having more control over their energy use.

Table 29. Mapping DR Programs to the Objectives (Order, p. 82-83)

IDRPP Considerations

The objectives set forth in this IDRPP are dependent upon a number of critical factors that could pose potential limitations and risks in the design and implementation of the IDRPP. The Companies have identified a number of critical factors and provided a brief discussion below on how to address them.

Third Party Involvement: The IDRPP is designed to take advantage of the expertise and cost savings that can be achieved through the involvement of third parties where applicable. As with all elements of this plan, the Companies have adopted this element of the strategy because they believe it to be the most effective and efficient path to an impactful DR program. The Companies have received expressions of interest from several third parties, but do recognize the possibility that the small size of the Hawaiian DR market could pose problems, in particular for some of the harder to achieve grid service requirements. The Companies' believe the collective opportunity will attract third parties, and will be prepared to expand responsibilities and the size of the internal DR teams if needed to expeditiously execute customer recruitment and contracting efforts.

Customer Participation: The Companies believe that the current design of DR programs will provide significant economic incentives for the customers to participate, but acknowledges that customer recruitment efforts or unforeseen technology limitations could limit the level of effective participation. The Companies will make the programs as "participant friendly" as possible, and coincidentally, will not compromise the IDRPP's primary objectives to increase participation. Contracting with load resources that cannot reliably meet grid service requirements or overcompensating participants will be avoided. The Companies will make mid-course adjustments to the implementation of the IDRPP as necessary in order to achieve its objectives, including more aggressive marketing programs and partnerships if needed (such as the one that will be pursued with Hawaii Energy).

Value of Grid Services: The Companies are aware that the value of a grid service may vary by island, and furthermore, may even change over time based on the evolving characteristics of the supply and demand portfolio. The Companies will evaluate the cost effectiveness of DR in the production simulation modeling being done as part of the PSIPs for each operating. Moreover, the Companies plan to re-evaluate the maximum price and tariff requirements as often as needed in the future.

Aggregate Capacity Threshold: Another consideration is the aggregate capacity threshold that may naturally exist for certain grid services. Based on the Companies' preliminary assessment, the value of DR resources associated with certain grid services may be of limited value unless they eliminate the need to turn on (or operate) a supply-side resource. Stated differently, the per unit value of a grid service will not always be linear – average values, and thus the Companies' willingness to pay, may be higher at certain thresholds. The Companies will incorporate this consideration into recruitment efforts and cost benefit analyses, and will be prepared to adjust compensation terms to account for different value tiers if appropriate. In the event that these thresholds are not reached in the early stages of IDRPP implementation, the Companies will seek to adjust accordingly. A more detailed assessment for each proposed program and associated grid service will be made by the Companies after initial contracts are consummated.

Under-Performing DR Resources: Underperformance or inability to meet performance specifications will create significant issues, and more for some grid service requirements than others. To minimize the potential for such issue, the contracts will have stipulations to penalize poor performance. If performance levels by program continue to fall below expectations, the Companies may also need to discount the contribution of the program based on performance levels seen over time. The companies must also evaluate if the defined DR programs provide the anticipated value in actual system operations and modify the program requirements if necessary to obtain the desired impact on operating costs.

Technology Upgrades: Many aspects of the IDRPP are contingent upon certain technology upgrades such as AMI deployment. Any factor impacting the completion of the technology upgrade phase may ultimately lead to delays in the implementation of the IDRPP.

Evolution of the Integrated DR Portfolio: The Companies will evaluate future DR trends on an ongoing basis, and adjust the IDRPP to take advantage of the emerging DR concepts. These concepts involve customer provided DR including on-site customer generation with storage capability, new customer end uses such as EVs, and other emerging concepts such as micro-grids. In doing so, the Companies will identify the needs the changing customer trends ahead of time, and will design DR programs that will best serve these needs before they materialize in the market.

Program Interaction: There is a certain degree of overlap across the DR programs included in the IDRPP. For example, a program such as RBDLC, which is designed to shift the load from peak demand periods to midday periods, ultimately lowers the DR potential that would be achieved through dynamic pricing programs. The Companies believe that each program in the portfolio accomplishes various objectives on their own, and a certain degree of overlap is unavoidable. In fact, a similar overlap exists between the DR and energy efficiency efforts. Achieving higher DR levels may work against achieving higher energy efficiency levels and vice versa. This is a strong reason for the Companies to collaborate with Hawaii Energy on an ongoing basis, and to evaluate DR and energy efficiency programs in a holistic way, ensuring customer incentives are aligned and maximum benefit is achieved at lowest system cost.

Greenhouse Gas (GHG) Emissions: IDRPP will have an impact on the system-wide GHG emissions of the state of Hawai'i, mostly because it will alter the way supply-side resources are dispatched, and may also ultimately lead to lower energy consumption overall. The Companies believe that it is highly likely to achieve a system-wide GHG emissions reduction through the implementation of the IDRPP, however on a per program basis, the net impact may not always be a reduction. An example would be the use of diesel powered generation units of customers for emergency or economic purposes. Due to the small size of these units in comparison to utility-scale generation, they usually operate on higher heat rates (i.e. lower fuel efficiency). This, in turn, leads to higher GHG emissions per amount of energy produced.

Nevertheless, in most applications of DR, such as shifting the load from evening to midday hours through RBDLC or use of DR resources to satisfy regulating reserve requirements of the grid, the Companies expect to reduce the system-wide carbon footprint. Assuming that the heat rate difference between a baseload and a peaking unit is one million Btu/MWh, and 160 pounds of CO2 is emitted per million Btu produced by the fuel mix used in Hawai'i, a 40 MW RBDLC program in 2020 across the three islands, could achieve a total GHG reduction is of 6,400 pounds of CO2 per day.[64] Similarly, using DR resources for regulating reserve purposes would directly translate into energy savings as the associated load resources would respond to the request by lowering their demand. The Companies plan to study the GHG impact of the portfolio in a comprehensive manner, in collaboration with Hawaii Energy to integrate the energy efficiency related reductions, and thereby obtain a system-wide GHG reduction credit. Such an integrated study would be used to fulfill the recently proposed EPA's requirement on CO2 emission goals.

[64] 160 pounds/MWh * 40 MW * 1 hr =6,400 pounds of CO2.

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5. IDRPP Economics

The IDRPP has been developed in order to take full advantage of DR in helping the Companies meet their respective grid service requirements. However, DR programs will represent only one element of the options available to provide grid services, with generation and energy storage assets also playing important roles. Together DR, storage, and flexible generation will combine to provide more robust, reliable, and cost effective power systems.

While a certain level of redundancy is important in maintaining system security and reliability, too much redundancy can result in higher costs to customers. Therefore, the need for and willingness to pay for any one of these elements will be driven, in part, by the availability and cost of the others.

IDENTIFYING VALUE

The value of DR will be determined according to avoided cost. Traditionally, the principal value of demand response, which was primarily for capacity deferral, was associated with the avoided cost of new generating capacity, and deferred capital costs will still be a major driver of value. For example, if there is a generation shortfall to serve the annual peak, a DR program that can deliver 15 MW in load reduction during the 5pm - 9pm priority peak period would translate to $26 million in deferred new capacity costs, assuming that the avoided capacity cost is based on a combustion turbine with an installed cost of $1,750 per kW.

However, the purview of DR is changing significantly in Hawai'i, with the operating role expanded to meet a wider range of grid service requirements, as defined in Chapter 2. The value of a DR program that can provide one or more grid services can be calculated according to the avoided cost of meeting that grid service requirement through other means; in other words, the cost to the ratepayer of meeting that requirement if the DR program was not available.

Another primary source of value can be avoided fuel costs. For example, starting a cycling unit to meet the evening peak reduces system efficiency in two ways: each unit started will typically operate at less efficient heat rates than those before it – hence its position in the commitment order – and there is also a system heat rate impact associated with starting a cycling unit at its minimum load. Under certain circumstances, which are dependent on the types of generating units that are available to the system operator, deploying DR may be more cost effective than starting a generating unit. If the O'ahu system needs just 8 MW to carry it through evening peak, for example, without demand response that would create two efficiency impacts:

1. Starting a cycling unit like Waiau 5 or 6 at its minimum load of 24 MW will mean an average heat rate of approximately 11,500 Btu/kWh, or approximately 10% more fuel per kWh than a reheat unit provides.
2. To accommodate that minimum load, the more efficient reheat units will have to back down to lower, less efficient output levels. Reducing the eight reheat units' output levels by 2 MW each means an average heat rate increase of approximately 25 Btu/kWh across the reheat unit fleet.

This situation is specific as DR may not avoid costs in other circumstances; the cost/benefit can be studied by analysis which deploys the DR at its anticipated rate. With demand response programs equipped for economic dispatch, as in this case the RDLC hot water heater program is, each dispatch event might save several thousand dollars by shifting that system load to the downside of the peak and obviating the need for the less efficient cycling unit. When the program can be run every day, at no additional cost, and with little if any discernable impact on participating customers, it creates additional value on top of the capacity value. The actual cost/benefit of DR would be evaluated by a production simulation which calculates the total impact on production costs if DR is made available for economic deployment.

Other sources of fuel cost savings could stem from any resource fast enough to provide Contingency Reserve, which on O'ahu would help reduce the spinning reserve requirement and thereby increase efficiency, or regulating reserve, which would mean less costly up and down ramping from existing generation (or perhaps fewer capital costs spent on frequency support batteries). This cost would also be captured in the production simulation which will determine the cost benefit of reducing the online generation reserve.

DR can also be employed to meet more "local" issues, such as the need for transmission and distribution reinforcements. There could be significant value in eliminating the need for a new substation by reducing peak loads on a confined set of circuits. The Companies will track localized issues, and where appropriate, geographically speaking, will adjust the maximum price to be paid for a grid service to account for the value of meeting any grid reinforcement needs with a "non-transmission alternative."

Avoided cost considerations for a given grid service could be based on several factors, including installed capacity costs, fuel costs, cost of alternatives, each of which depend on the current state of the system. Potential avoided cost calculation methodologies include:

Capacity: The cost of new capacity deferral, likely to be the per kW cost of a reciprocating engine or combustion turbine.

Regulating Reserve: The cost of a frequency support energy storage device, or the cost savings from reduced regulating reserve requirements, as calculated using a production cost model.

Contingency Reserve: For O'ahu, the fuel cost savings resulting from a reduction in the contingency reserve requirement from thermal generation commensurate with the DR resources assumed to meet the contingency reserve requirements, as calculated using a production cost model. For Maui and Hawai'i, this would offset under-frequency load shedding, producing a customer benefit but not a readily-calculated economic benefit.

Non-AGC Ramping: The fuel cost savings and maintenance savings resulting from deferring unit starts for a wind down-ramp. May offer an alternative to having to install additional fast-start capacity, in which case the evaluation could be similar to the capacity deferral.

Non-Spinning Reserve: At present, the cost of maintaining existing resources that currently meet non-spinning reserves. For O'ahu, this cost will be represented by the estimated operations and maintenance cost difference between Waiau 3&4 continuing to operate versus the cost of layup.

Advanced Energy Delivery: The production cost savings incurred by shifting demand, as compared to production costs if demand were not shifted.

All of the above avoided costs are offset by program costs and reduced sales.

Where a resource or program can meet two or more grid service requirements, but not simultaneously, its avoided cost will be determined using the higher of the costs that can be avoided.

A DR program is only as valuable as its avoided cost, and that avoided cost will vary over time as a result a large number of variables, including system demand, thermal generating unit operating parameters, fuel costs, variable renewable energy penetration, the installed cost of substitutes, and other portfolio characteristics. The Companies will track these costs regularly and adjust them as often as annually, if needed, to ensure that customers are not overpaying for grid services that could be accomplished more cost effectively by other resources.

Avoided costs and prices for DR resources are expected to vary by island.

SETTING DR PROGRAM COMPENSATION LEVELS

The "maximum price" paid for a DR program would be the difference between the avoided cost and the program's operational cost. The "avoided cost" is the cost of an alternative resource (energy storage or a generator) providing the equivalent service. At the "maximum price," the overall rate impact to customers would be economically neutral. To create the maximum benefit and participation, we will bring our DR programs to the open market to best determine price and appeal, and drive their adoption through third-party agents selected for their expertise and experience. Whenever the market prices paid for DR is less than the "maximum price," all customers benefit, and the participating DR customer receives an additional credit or payment.

In order to acquire as many DR resources as feasible at prices that maximize value to all customers, the Companies will employ market mechanisms such as descending price auctions for services, with the starting auction price set at the maximum acceptable price.

MEASURING AND COMMUNICATING COST EFFECTIVENESS

The cost-effectiveness of DR will vary as other elements of the power supply portfolio change. The Integrated DR Portfolio will be analyzed in the context of the PSIPs that will be filed with the Commission on August 26, 2014.

The DR programs will, by definition, be cost effective. For example, customer compensation will be determined at auction, with auction reserve prices set such that any closing bids that exceed the value of the program (as measured annually based on avoided costs) will not be accepted. The Companies' fixed costs associated with the integrated demand response portfolio as a whole will be relatively modest. There will be some annual labor and outside service costs, as there have been to date on O'ahu.

Cost Benefit Analysis

Cost benefit analyses will be filed annually, under protective order to protect the integrity of the market-based processes utilized to acquire DR resources.

Submission Plan

The Companies propose to file cost benefit analyses for all programs on all islands, each year on or about October 1.[65],[66] Program benefits will be determined according to the avoided cost methodology described earlier in this chapter. The Companies will complete avoided cost calculations for all grid service requirements on all islands, which will then be used to inform the maximum price considerations. Program costs will include incentive payments and any program specific administration costs borne by the Companies.

Confidentiality Will Be Important

The Companies have proposed to procure future DR resources in the interest of securing the best price possible for its customers. Preserving the confidentiality of program costs and benefits will be critical to capturing the full benefits of competitive pricing. This will be especially important where the Companies could take more of the grid service requirement than the market for DR resources will bear – in such cases, where demand exceeds supply, it will be important that DR participants and aggregators not have access to the Companies' DR avoided cost calculations.

[65] Conducted according to the four cost effectiveness tests from the California Standard Practice Manual, including the Participant Cost, Ratepayer Impact Measure, Total Resource Cost, and Program Administrator Cost tests.

[66] The actual timing and scope of the filing of annual cost-benefit analyses and other related filings are subject to change per guidance from the Commission.

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6. Demand Response Portfolio Roadmap

Over the next 20 years, the Companies' power systems will each need significant grid services in order to integrate higher concentrations of variable renewable resources into the power supply mix. DR will play an important role in cost effectively meeting capacity and ancillary service requirements. The Companies have proposed an aggressive portfolio of DR programs to provide these grid services and are fully integrating this portfolio into the Power Supply Improvement Plans for each operating company. The DR portfolio will be procured and priced through transparent and market-based processes, which will be designed to establish a diverse and cost effective set of DR resources for the benefit of all customers in the Companies' systems.

Importantly, the aggressive approach to utilizing DR programs also creates new opportunities for customers to reduce their energy costs through participation in Company sponsored DR programs. The Companies are excited to engage with our customers to provide them with tangible benefits, while also allowing them to play a role in meeting the challenges associated with the transition to a new portfolio of resources for meeting system needs. This chapter outlines the action plan for implementing the Companies' Integrated DR Portfolio.

INTEGRATED DEMAND RESPONSE PORTFOLIO OVERVIEW

The Integrated DR Portfolio is designed to provide system operators on each island with new tools for providing the required grid services. The required quantities and value of each grid service will vary by system over time. Therefore, the integrated portfolio approach provides a way for the Companies to market, secure, and provision DR programs.

The DR portfolio is "integrated" in at least three ways:

- The DR Portfolio will be fully integrated with the PSIP for each system. The DR programs are specifically designed with the ability to provide the required grid services. The PSIPs are being developed to fully utilize available cost effective DR resources to meet the defined needs of each grid. Because there are differences in the types of existing loads on each system, the Companies expect that the PSIPs may determine that the cost effective mix of DR programs and other sources of grid services may be different for each system.
- The DR programs are fully integrated across the Companies, such that a third party provider or an end use customer operating on multiple islands can provide the same DR resource, in the same manner in each system. This should expand the availability of DR resources, by making it easier for loads to participate.
- The internal operation and administration of the DR programs will be integrated across the Companies, with a focused center for DR administration (e.g. a "DR Department") and common administration of the programs to serve all three Companies. Where necessary, the Companies will add capabilities in the form of additional employees and/or engagement of outside resources. The centralized approach will leverage the Companies' existing and future DR expertise, resulting in the lowest possible cost of administering the DR programs.

DEMAND RESPONSE PORTFOLIO ACTION PLAN

This section of the IDRPP provides a high level view of the action plan for implementing the DR portfolio. Chapter 7 provides a detailed view of the near term implementation steps over the 2015 – 2017 period.

DR Portfolio Implementation Timeline

The Demand Response Portfolio Action Plan described in this Chapter provides for immediate action across all three Companies, as shown in Figure 16. The existing programs, primarily limited to O'ahu, will be modified as previously discussed in this report. The full portfolio of DR programs would be launched across the Companies in 2015, with the actual delivery of grid services from new DR programs expected to occur by January 2016. An expedited Customer Generation program will be launched for Maui Electric; that program is expected to deliver capacity in the summer of 2015.

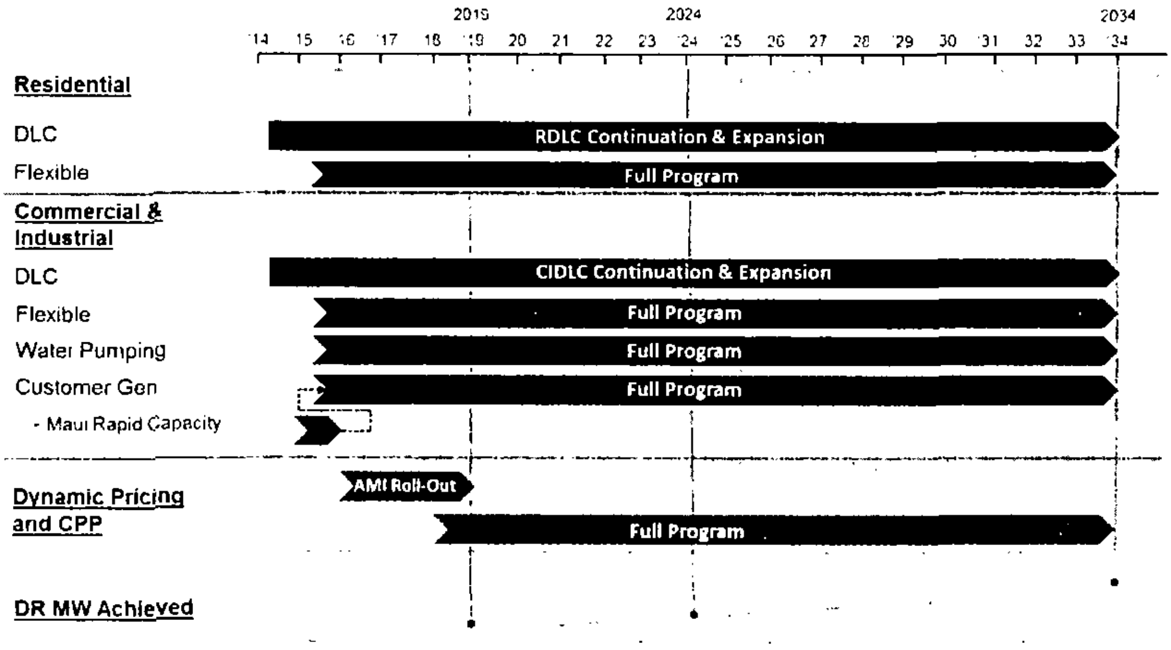

Figure 16. Timeline for the DR Portfolio Action Plan

Figure 18 also illustrates the importance of the Companies' smart grid plan in implementing new Dynamic and Critical Peak Pricing programs. These DR programs will be rolled out as the AMI system, which is included in the smart grid infrastructure, is implemented.

Measuring Performance

The success of the IDRPP will be measured against several objective metrics. These metrics include:

Timely Implementation: Ability of the Companies to execute against the near term Implementation Plan presented in Chapter 7.

Realizing the DR Potential: Total MW of DR resources procured through the auction and/or tariff based programs.

Cost Effectiveness: Total magnitude of savings between the "maximum price" for each Grid Service and the actual price paid for each service.

Greenhouse Gas (GHG) Impact: The DR portfolio's success in avoiding fossil-fueled generation, with the resulting positive impact on GHG emissions.

DR Program Operational Performance: The actual performance of a given DR program measured against the specifications of the DR program. Where applicable, this will be measured for each DR resource provider (i.e. individual participating customer and/or third party aggregator).

The Companies will measure these and other DR portfolio metrics on an ongoing basis and will prepare an annual summary.

Regulatory Alignment

The Companies are committed to maximizing the economic potential of all available, cost-effective DR resources on each island grid. In order for these efforts to be successful, supportive regulatory treatment of these activities is essential. There are four basic regulatory components that need to be addressed as the Companies move forward with implementation of the DR portfolio. These are:

- Cost Recovery for Demand Response Resource Payments
- DR Operations and Administration Cost Recovery
- DR Program Achievement Incentives
- Cost Recovery for the Transition of existing DR Programs

While the Companies are open to all reasonable regulatory approaches, the detailed Implementation Plan in Chapter 7 provides the Commission, for its consideration, proposed approaches for each of these components.

ROLE OF THIRD PARTY AGENTS AND AGGREGATORS

We anticipate contracting with third-party agents and aggregators to act as service providers on our behalf. They are the end use and control system experts whose expertise can be leveraged to expedite aggressive implementation of our plan. This approach seeks to enable our customers to benefit quickly and effectively from a robust and diversified DR portfolio that can provide the required grid services. Such third parties will be pre-qualified and/or certified for participation, based on a range of criteria, including:

- Ability to perform, including prior experience, feasible plan, quality of project team, ability to deliver locally
- Technical capabilities: Engineering and operations skills, capabilities, and technologies
- Project specific needs: Dependent on project. Examples: field presence in jurisdiction, expertise with specific market segment, unique or proprietary software, etc.

- Terms & conditions: Adherence to the Companies' standards and contractual provisions.

In addition to third party agents and aggregators, the Companies anticipate that larger, more sophisticated customers will want to consider participating in the programs directly. The Companies intend to encourage such participation and will pre-qualify those customers for direct participation. The primary pre-qualification issue will be the customer's ability to meet the communications and control technology and interface requirements for each DR programs in which they wish to participate.

For all DR resources, whether acquired directly, by a third party, or end use customers or through a tariffed DLC program for residential and small business customers, the Companies will be responsible for scheduling, dispatch, real time monitoring, and performance verification.

A Program Management Delivery Model is outlined in Table 30. The Companies propose a ten-step method for developing, implementing, promoting, managing, and evaluating their demand response portfolio. It should be stressed that under this model, the strategic elements (e.g., design and development) and certain operation elements (e.g., scheduling, dispatch, monitoring, and performance verification) would remain the responsibility of the Companies for all DR programs. Program recruiting and equipment provisioning at the customer sites may be managed directly by the Companies or by a third party, depending upon the specific DR program (e.g., load control programs vs. time-based rate Schedules and Riders) and other factors. The Companies would handle the actual scheduling, dispatch, monitoring, and performance verification.

DR Capability Area	Existing Delivery Model (RDLC)	Planned Delivery Model*	Integrated DR Portfolio Delivery Commentary
1. Program Design & Development	Hawaiian Electric	A: Hawaiian Electric Companies	• Maintain in-house and implement continuous improvement cycle
2. Marketing & Communications	Hawaiian Electric & 3rd Party	A: 3rd Party B: Hawaiian Electric Companies & 3rd Party	• Hawaiian Electric will develop an overarching brand identity for the DR programs • 3rd Party vendor and Hawaiian Electric will create messaging, develop content, segment the customer market and launch the marketing initiative
3. Auction Procurement Process	Hawaiian Electric	A: Hawaiian Electric Companies	• Institute 4 step procurement process 1. Circulate DR program requirements & solicit DR proposals for pre-qualification of potential providers 2. Pre-qualify auction participants 3. Conduct reverse auctions to select and price DR provided services 4. Finalize contracts with winning bidders
4. Participation Agreement	3rd Party	A: 3rd Party	• Oversee 3rd Party Customer agreement process
5. Enablement	3rd Party	A: 3rd Party	• Oversee 3rd Party customer enablement and technology enablement
6. Maintenance & Operations	Hawaiian Electric & 3rd Party	A: 3rd Party	• 3rd Party Program and technology maintenance
7. Effectiveness Evaluation	Hawaiian Electric & 3rd Party	A: Hawaiian Electric Companies	• Based on auction results and the operational performance of each contracted provider, the Company will be able to monitor cost effectiveness on an ongoing basis.
8. Vendor Mgmt, System Integration and value tracking (oversight of vendor tasks 2, 4, 5, 6, 7 & 10)	Hawaiian Electric & 3RD Party	A: Hawaiian Electric Companies	• Establish a Demand Response Department, serving all three companies, led by a Manager. In terms of program management, this overarching function monitors 3rd party effectiveness and executes the developed vendor management process. Also responsible for DRMS selection, integration, and use, including integration with Energy Management Systems and communications interfaces with DR providers.
9. Regulatory	Hawaiian Electric	A: Hawaiian Electric Companies	• In house capability that implements new Regulatory report processes
10. Billing & Incentive Payments	Hawaiian Electric & 3rd Party	A: 3rd Party B: Hawaiian Electric Companies	• The Companies will pay for DR provided Grid Services on a monthly basis, based on the auction clearing prices. To the extent those are provided by third parties, the third parties are responsible for settlement with the end use customers they are working with.

**Delivery Model is dependent on RFP response. A: Optimal Outcome, B: Second Optimal Outcome.*

Table 30. Integrated DR Portfolio - Program Management Delivery Model

TECHNOLOGY CONSIDERATIONS

As discussed in Chapter 2, providing the grid service requirements with DR programs requires standards for provisioning and DR program performance including real-time communication and speed of response. Additionally, measurement and verification (M&V) is an essential program performance element. Accordingly, the Companies will specify the technical design requirements for the DR architecture. Solutions offered by qualified DR third-party providers must be scalable, readily compatible with changes in technology over the term of the DR programs, and cost effective. The categories of overarching design principles include:

Cyber Security: The DR architecture must incorporate the latest cyber security techniques and standards.

Scalable Solutions: The DR infrastructure should allow for the management of hundreds of thousands of endpoint devices and customer loads.

Leverage Industry Protocols: The infrastructure should leverage open standards and industry best practices, establish repeatable processes and patterns, and provide a template for all demand response solutions (e.g. "OpenADR").

Interoperability: The DR technology solutions and requirements should be both vendor and platform independent; "plug and play" DR architectures should be leveraged as much as possible to allow for the deployment of scalable and interoperable solutions.

While the final DR portfolio architecture will depend, in part, on points of integration with vendor technology solutions and third party delivery models, there are common technical requirement categories including control systems, communications methods and protocols, and control devices. Some solutions may cover all three of these categories on a turnkey basis. The Companies intend to build the foundation necessary to institute a "plug and play" architecture by implementing a DRMS that interfaces with the system operator, and the communications network. The DRMS would enable DR innovation and flexibility for DR providers and for end use customers across a range of end uses.

Demand Response Management System

A key technical requirement for the implementation of the Companies' IDRPP will be the installation of a DRMS across the Companies. A DRMS is a software platform that will allow the Companies to manage all aspects of their demand response programs through a single integrated system. A DRMS solves the challenge of creating an automated, integrated, and flexible demand response solution and could be integrated or interfaced with the Companies' energy management systems (EMS) and AGC systems. In addition, the DRMS would allow the Companies to scale DR capacity in a cost-effective way by automating processes across multiple programs, islands, and customer classes.

A DRMS solution will enable the proposed programs in two key ways; direct control and indirect control. For direct control the DRMS will initiate a signal designed to physically interrupt or cycle the load (e.g. air conditioners, hot water heaters, pool and irrigation pumps, motors) or manage the dispatch of customer owned generation. For indirect control the DRMS will notify consumers of a DR event and, if applicable, communicate prices signals and time constraints related to that event. A DRMS system would integrate residential, commercial and industrial programs and can be used to quickly launch small pilot deployments, and manage full-scale DR projects.

At the present time, the Companies rely on direct load control (DLC) through one-way paging communications. This one-way only capability limits the Companies' ability to determine whether a switch is working, maintain end-to-end visibility of the infrastructure and in general makes it difficult to verify actual load reductions and predict future load-shed potential and to customize and support DR programs. In the future, the existing control system would be phased out and replaced with the DRMS and its associated infrastructure. This upgrade will allow the Companies to measure individual customer and overall program performance, predict load-shed potential, and allow customization of DR programs. The key functional elements of the DRMS will include:

Estimation: Analytics both during and after an event to better assess how the system performed and how many customers participated

Dispatch Optimization & Notifications: Algorithms that initiate program events based on estimated load forecast, demand resources available, and/or economic impact or provision of manual control that allows the system operator to initiate a DR event.

Aggregation/Disaggregation: Ability to determine the total demand response available, based on customer participation and the availability status of participating customers

Measurement and Verification: Measurement of a specific customer's performance during a DR event against the program requirements, calculation of customer load baseline (i.e. the expected load of the customer if the DR event had not been called) and comparison of the actual performance during the event to the baseline and the resulting impact on DR program compensation and customer billing.

Reporting & Dashboard: Metrics, reports and visualization tools that allow the Companies to validate and analyze the effectiveness of DR programs and the performance of those programs during actual events.

Field Device Management and Provisioning: Functionality that provides the company with the ability to remotely manage field devices (e.g. load control switches) including initial provisioning, firmware updates, and changes in a specific customer's participation in a given DR program (e.g. a customer chooses to move from one DR program to another).

Participating Customer Portal: Customer-facing portal that allows the participating customer to understand and summarize their performance and the realized economics of their participation in a DR program.

DRMS Implementation

DRMSs have been successfully implemented at other utilities. For example, Nevada Energy (NVE) has implemented a retail market-level DRMS that manages 14 active DR Programs (11 residential, 2 commercial and 1 industrial) program, with over 200 MW of available DR across over 200 substations and 1,300 feeders with 5 device technology types. PJM's wholesale market-level DRMS is an end-to-end solution that acts as the command and control system managing all activities and data related to DR, including program management, resource management, registration management, event management, notification management, measurement and verification, and regulatory reporting.

The vendor landscape for DRMS consists of large established energy software providers, as well as new software specialists with an energy industry focus. The Companies will prepare a carefully designed list of technical and functional requirements around the integrated DR portfolio taking into account program speeds, frequency and duration as well as more general program characteristics.

A key requirement for the installation of a DRMS for the Companies is integration or interfaces between it and the Companies' EMS.[67] Another requirement is that the DRMS integrates to the Companies planned smart grid meter data management system (MDMS) and existing customer information systems (CIS) to ensure that billing and settlement related to DR programs is timely and accurate. In terms of a wider system blueprint there will be considerations around the interface between third party systems and the Companies' DRMS. From a system architecture and systems integration

[67] The Companies operate different EMS systems on O'ahu, Maui, and Hawai'i: the former utilizes Siemens technology whereas the latter two utilize Alstom technology.

perspective there will be certain custom integrations between the DRMS and other systems, including:

Operation Systems: EMS integration and/or interfacing for automated load control

Back Office Systems: CIS billing and eventual Meter Data Management System (MDMS) integration

Communications: Smart Grid IPv6 communications network

"Behind the Meter" Technologies: Home Area Networks (HAN) and devices such as Programmable Controllable Thermostats (PCTs), and direct integration with automation systems already installed within commercial and industrial facilities e.g. existing Building Management Systems (BMS).

The graphic below highlights an example representation of the interfaces to both DR aggregation systems and standard utility systems.

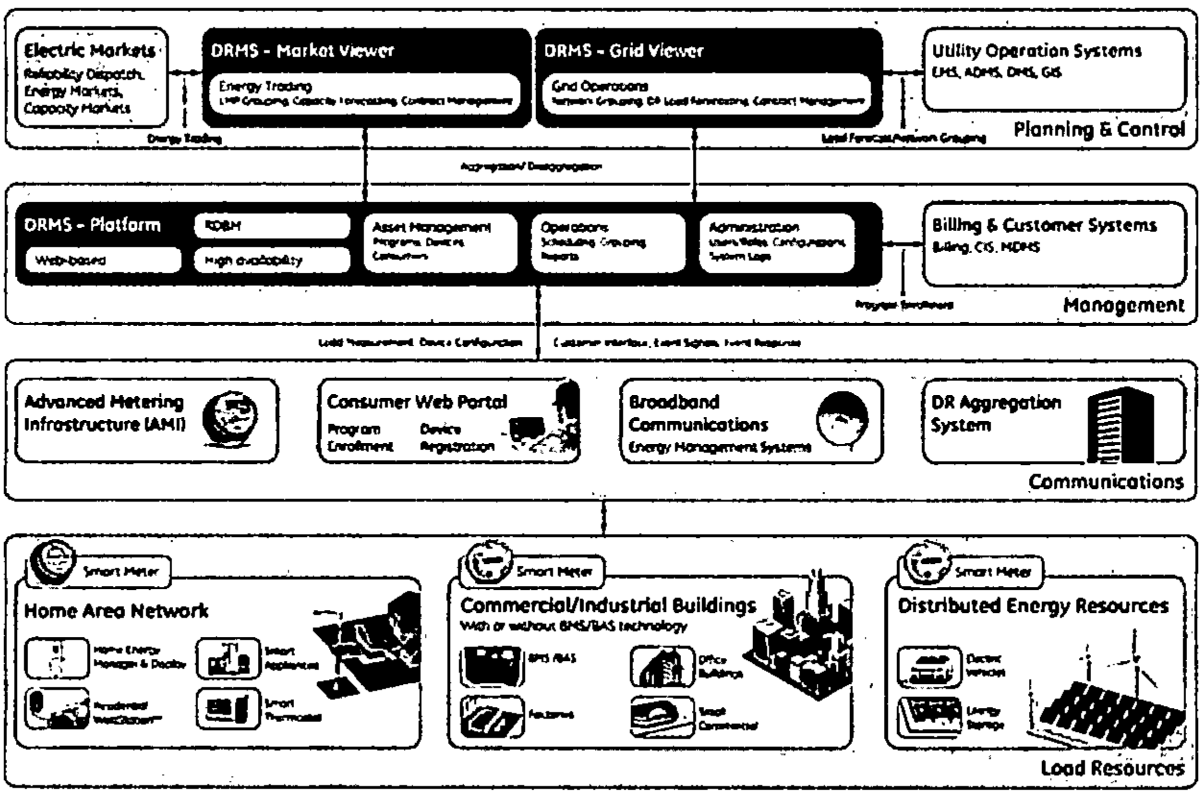

Figure 17. GE PowerOn™ DRMS Solution Overview[68]

[68] Source: GE

It must be noted, however, that there are dependencies and limitations in any wider end-to-end DRMS solution that will need to be addressed including:

- Latency and bandwidth limitations of the communications network: A DRMS is constrained by the latency and bandwidth limitations of the communications network. Table 35 outlines some of the limitations that may exist with various networks. Latency and bandwidth considerations for DR programs will be a key driver in the specifications of the DRMS design requirement.
- System integration challenges: In some markets, DR programs that require near real-time response such as regulating reserve are provisioned through direct control systems that may not be integrated with an end-to-end DRMS. Complex architecture and lack of system integration make it difficult to create a coordinated DR dispatch and response verification process in these instances. The Companies will make every attempt to integrate DRMS applications with other systems, devices, and communications networks as appropriate and cost effective.
- Maturity of the DRMS market: The DRMS market is relatively nascent, with some products in the market not having been tested and proven across a wide and varied list of deployments. This could affect DRMS development times and system integration costs.

Communications

Another key technology requirement is the necessary communication networks and protocols. At present, the Companies' largest DR program, RDLC utilizes one-way paging technology. This system can cycle air conditioners and other high-energy use appliances such as water heaters and pool pumps during peak demand times to reduce system demand. However, the RDLC program and the overall Integrated DR Portfolio will require an improved two-way communications network to enhance feedback on customer response to events and to provide the ability to check individual device status and reachability.

With the proposed smart grid IPv6 communications network, programs such as Dynamic Pricing will benefit from improved two-way communications. Indeed, the Companies' planned smart grid RF mesh network will provide an always on, two-way network that can provide the Companies and customers to access energy consumption data. This network can also be leveraged for pricing programs and for complex bill processes associated with DR programs. Further specification of the required network technical capabilities will be developed to enable those DR programs with faster response needs.

At the customer premises, industry standards such as ZigBee and the related gateway device specifications should be considered when connecting networks. Similar to the smart grid system, a gateway uses the customer's broadband network as the communication backbone while using ZigBee protocols to communicate with a home area network (HAN) inside the customer's premise for device control. While many of the programs that are proposed in the IDRPP will require broadband or other Wi-Fi related communications networks due to the speed requirements, there will be limitations around the availability of customer broadband and the relative 'uptime' needed. Ultimately, each program will have different communications technical requirements, and will leverage a host of solutions. Table 31 below outlines some of the technical considerations and limitations of each of the networks, and key decision factors when pre-qualifying customers and third parties to provide DR resources.

Function	Paging	AMI	Gateway	Cellular	Wi-Fi
Effective Throughput Speed	High*	Low	High	High	High
Network Availability	Always on	Always on	Dependent on customer	Always on	Dependent on customer
Endpoint Online Status	None	Post-event analysis	15 minutes	15 minutes	Immediate
Load Control	Immediate	Scheduled	Immediate or scheduled	Immediate or scheduled	Immediate or scheduled
Acknowledgement	None	Next meter read	15 minutes	Immediate	Immediate
Commissioning	Simple	Complex	Complex	Plug and play	Low
Consumption Display	None	Local real-time	From meter read	From meter read	From meter read
Remote Device Telemetry	No	No	Yes	Yes	Yes
Remote Device Configuration	Some	No	Yes	Yes	Yes

Table 31. Communication Functionality Comparison[69]

Control Devices

Once the control system and a communications network are in place, a further key technical requirement will be the installation of control devices that can switch or cycle end-use devices at customer premises. At present, a number of vendors offer products that would satisfy a range of grid service requirements including Multiple Load Control Switches, Single Load Control Switches and Programmable Communicating Thermostats. The exact functionality of these types of devices varies depending on the load they are intended to control, the grid requirement they are satisfying, and the flexibility desired for utilization of the control device across multiple purposes (e.g.

[69] Source: Comverge by Howard Ng "The Evolution of Communications for Demand Response.

multiple DR program functionality). Approved control device lists and standards will be developed by the Companies as part of the DRMS specification process.

Multiple Load Control Switches: Some vendors offer load control relay (LCR) technology in large enclosures that support the installation of up to three LCRs in a single device chassis. Each LCR in the series contains individual addressable relays, a combination of 5-amp and 30-amp relays.

Single Load Control Switches: Single LCR devices will provide the Companies with smart load cycling, power quality protection and a variety of communication media choices.

Programmable Communicating Thermostats (PCT): PCTs are compatible with most 24-volt heating and cooling systems and can operate over broadband internet-based communications networks.

Technology Standards

As outlined for the overarching technology requirements, interoperability will be a key requirement throughout the qualification process. Solutions and requirements should be both vendor and platform independent and "plug and play" architectures should be leveraged as much as possible to allow for the deployment of scalable and interoperable solutions. For example, Open Automated Demand Response (OpenADR) is a family of specifications and standards driving progress in automated demand response. It provides an open and standardized way for customers (through in-premise load control devices), load control aggregators, and system operators to communicate demand response signals to/from each other using a common language over any existing IP-based communications network, such as the internet. In 2014, the OpenADR 2.0b Profile Specification was published by the International Electrotechnical Commission (IEC). This specification describes a web services protocol that enables fast, reliable and secure information exchange among demand response program operators, aggregators and end customers. This standard will be leveraged throughout the Companies' technical requirements.

Customer-Owned Devices

In addition to the PCT technical requirements, the pricing related program may consider the deployment of a Technical Assistance Demand Response initiative. This is dependent on how the pricing programs ultimately develop. However, in other markets, customers seeking assistance and incentives for DR measures have made good use of Technical Assistance initiatives. These initiatives provide eligible customers, primarily business customers, free DR site assessments and explanations of the financial benefits of both pricing programs and active DR programs. The technical assistance process may be initiated by the Companies' customer account representative or the customer with the purpose of identifying applicable demand response practices and methods, and recommend measures, technologies, and third party providers to achieve active demand response potential utilizing the customer's load.

7. Implementation

The implementation of the IDRPP across the Companies will be a major undertaking. The filing of this IDRPP is the first step and, while the Commission is reviewing the IDRPP, the Companies will be moving forward with many of the detailed planning and implementation actions required to aggressively tap into the available demand response market. This approach will include a transition that appropriately accommodates contributions from the current participants to the new and expanded market-based approach.

The Companies are committed to aggressively taking advantage of available DR resources to meet grid service requirements and reduce costs to customers. At a very high level, 2014 and 2015 are years of major transition for the DR programs at the Companies. As the portfolio of new DR programs and new market-based approaches are launched, certain existing O'ahu and Maui programs and recovery mechanisms would be modified to comply with the Order. 2016 will be the first full year of operation of the DR Portfolio across all three Companies for the new market-based DR programs. With the subsequent implementation of the Companies' proposed Smart Grid Program, the DR pricing programs enabled by the smart grid AMI and communications infrastructure will be further expanded.

The high-level work streams and implementation schedule are shown in Figure 18. Each work stream is discussed in detail below, along with the detailed task schedule and high-level action plan for each.

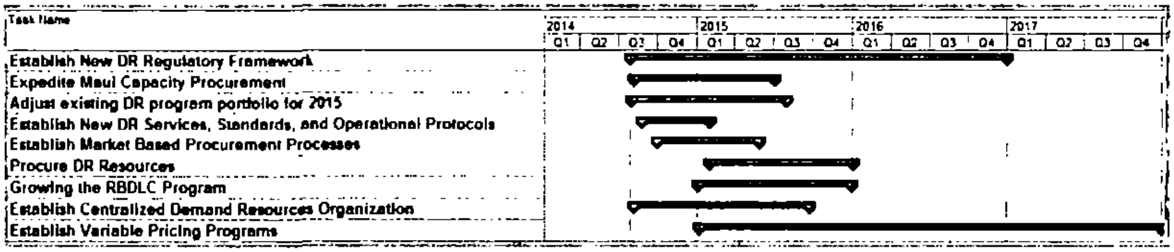

Figure 18. High level work streams and implementation schedule

ESTABLISH NEW DR REGULATORY FRAMEWORK

This IDRPP proposes an aggressive, market-based approach to procuring DR resources to fulfill grid service requirements on each island. As the Commission anticipated in the Order, the implementation of this plan will require a new regulatory framework for DR, including a transition of the current programs.

Demand Response will no longer be a pilot, an experiment, or a "nice to have" resource, but rather will be a critically important portfolio of demand-side resources (and some supply-side resources) that will contribute to the safe, reliable, and cost effective operation of each of the Companies' power systems. As such, the costs of these programs are proposed to be recovered through base rates and standard cost recovery methods, rather than through special surcharges subject to annual renewal. The Companies believe this regulatory treatment is consistent with the guidance provided by the Commission in the Order. The Companies are open to guidance on this matter from the Commission, as agreement on cost recovery mechanics should not defer implementation of the DR portfolio.

To transition the existing RDLC, CIDLC, and Fast DR pilots to permanent programs and to fund the new GIWH pilot program, the cost recovery for the current DR pilot programs is proposed to be continued in 2015 using the current surcharge recovery mechanism, subject to Commission approval. The new regulatory framework is anticipated to entail a Commission-approved tariff mechanism that aligns the timing of the proposed cost and benefits recovery mechanisms. The general proposal for the implementation of the tariff mechanism is discussed below and the detailed review of the revenues and expenses associated with each tariffed demand response program will be presented in the context of the Companies' respective rate case proceedings (consistent with the Commission's guidance in the Order). The implementation work stream, as described below, will execute the transition from special surcharge to standard rate treatment for all three Companies over the 2015 through 2016 "transition" time period.

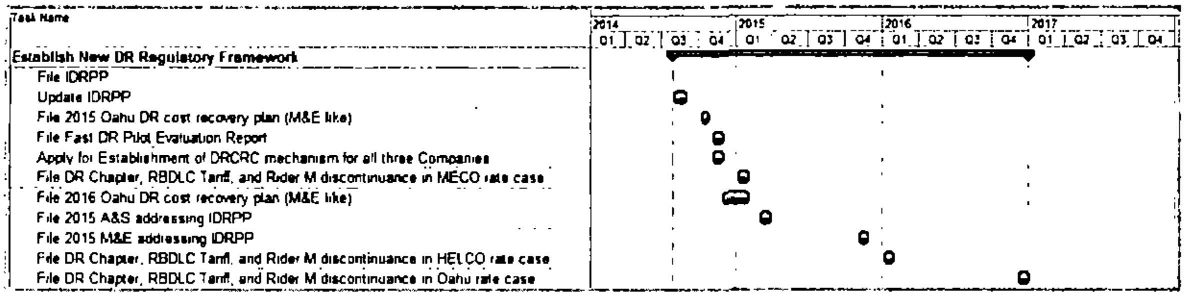

Figure 19. Implementation schedule for regulatory activities

2015 DR Pilot Program Cost Recovery

As detailed below, 2015 will be a year of transition for the existing RDLC, CIDLC, and Fast DR pilots, as well as the recently approved GIWH pilot. The Companies plan to file for Commission approval for the continuation and transition of these existing pilot programs to the newer market-based process within 60 days after the date of this filing. The Companies will seek approval to recover the proposed 2015 costs for these existing pilot programs through the DSM Surcharge mechanism, until such time that the Commission has approved the necessary recovery mechanism for the new tariff-based market-based auction programs.

The Companies will propose a new cost recovery and company performance incentive mechanism for demand response. The Companies believe a company performance incentive is appropriate and a high-level outline of the Companies' thinking is included below for the Commission's review. The Companies are open to suggestions for other cost recovery and company performance incentive mechanisms.

A company performance incentive mechanism, consistent with Act 37, would be designed to reward the Companies for growth in the availability of DR resources. The Companies plan to develop a detailed performance incentive proposal in the fourth quarter of 2014. To the extent that agreed benchmark levels of DR resources are contracted, the Companies will propose that a company performance incentive be recovered through the Demand Response Cost Recovery Clause (DRCRC), as described below.

The Companies intend to seek recovery of the costs and the reconciliation of the benefits of DR resources in two ways:

- The Companies' labor and non-labor costs for planning, designing, operating, administering, and evaluation of the portfolio of DR programs are proposed to be included in the next rate proceeding as filed by each Company separately.
- Implementation costs paid under approved tariff provisions, such as those for customer financial incentives, and payments made by the Company for the

procurement of grid services provided by third parties or end use customers using DR resources, are proposed to be recovered through a newly proposed Demand Response Cost Recovery Clause (DRCRC). The DRCRC recovery mechanism would conceptually parallel the revenue requirement and reconciliation balancing mechanism, in a manner similar to that used for the Purchase Power Adjustment Clause (PPAC). The Companies plan to file with the Commission its detailed proposal for the DRCRC concept by the end of 2014. The implementation of the DRCRC mechanism for each Company is necessary to enable the orderly implementation of the new market-based DR services. Until the Commission's approval and the Companies' implementation of the market-based DR procurement processes, the Companies anticipate the continued recovery of the existing DR pilot programs through the current surcharge mechanism.

Program Implementation Activities for 2015

The Companies propose to further enhance the value and capabilities of its existing DR programs by utilizing new technologies that are aligned with the Companies' Smart Grid Roadmap (e.g. AMI).[70] The new program designs will be based upon a market-based approach for acquiring DR resources, and an enterprise-wide operational strategy for providing reliable and cost-effective DR operations across the islands grids. As described below, for planning purposes the Companies anticipate the transition to the market-based approach and the alignment to the Smart Grid Roadmap with enhancements and modifications to the existing programs beginning in 2015.

Action Plan and Initiatives

- Develop the Demand Response program branding for the Companies' efforts. The DR brand will provide customers with a clear understanding of the purpose of the DR Programs, the contribution DR programs will make to a clean energy future, and how they can make a contribution to this future.
- Expand upon the use of the GIWH technologies to support the scalability and adoption of DR resources in the residential and small and medium business (SMB) market sectors. A GIWH system is a type of water heater technology that can provide load control and thermal storage capabilities over various timeframes, and can potentially be used in a variety of ways, including integration of variable renewable energy, load shifting, and provision of ancillary services. The Companies have undertaken multi-year research, development and demonstration initiatives and will continue its field trial activities and technical readiness evaluation for full commercial deployment.

[70] Smart Grid Roadmap & Business Case filed as a letter filing made March 17, 2014.

- Maintain and continue the upgrade of the existing residential and commercial programs starting in 2015, maintaining the current customers and commercial terms until such time that the market-based processes can be developed and implemented. The small business DLC customers will be transitioned to the new RBDLC; the remaining participants in the CIDLC and Fast DR programs will be merged into a single unified technology platform using the existing standards based operational systems. The purpose for continuing that upgrade of the legacy to the newer two-way systems is to enable a smooth transition of the utility-administered program to the proposed market-based model. The Companies engineering and operations will ensure that the standards deployed will be technically and operational compatible with the evolving grid service requirements.
- Continue the implementation of newer two-way, standards-based, DR technologies that support and enhance the value of the Companies planned smart grid program communications and metering infrastructure for residential and SMB participants. Continue the project management, engineering and operations of the newer load management systems deployed using Silver Spring Network's IPv6 communications network.
- Complete the planning, procurement, installation, and integration of the DRMS that will enable the integration of customers and third-party providers of DR with the Companies operations. Develop and issue the Request for Proposal for a DRMS. Evaluate and select an enterprise-wide DRMS solution and align the necessary engineering and operations business unit to support it.
- Continue the enablement activities consistent with the IDRPP for privately-owned and municipal water and wastewater facilities on all islands. Maui Electric intends to continue pursuing the development of a new DR capacity program in collaboration with the County of Maui (COM) DWS. While the Companies are pursing the implementation of the new DR regulatory framework discussed above which includes the requisite approval of the new cost recovery mechanisms, Maui Electric will be aggressively pursuing the next steps of designing and contracting a DR capacity program with the COM.
- Collaborate with Hawai'i Energy and Energy Excelerator community partners to seek out opportunities for DR and energy efficiency (EE) program concepts and to coordinate the interaction with potential customers and program funding for customer enablement and participation. The effectiveness of the Integrated DR Portfolio would be enhanced through collaboration by the Companies with Hawai'i Energy. Working together and sharing load research and other customer data will lead to better definition of customer choices for energy efficiency and participation in DR Programs.

- Pursue partnership opportunities with Hawai'i Energy and Energy Excelerator community partners to jointly develop market opportunities for DR. Leverage the incentives offered by Hawaii Energy, encourage and pursue specific pilot opportunities for mandating and/or incentivizing DR capabilities in solar water heating systems, providing incentives to add DR capabilities in EE projects, pursue the engineering of water heating and air conditioning DR control such as the previously mentioned GIWH expansion projects.

General Rate Case Filings

Beginning with the planned Maui Electric 2015 test year rate case, the Companies will seek to recover labor and non-labor costs for planning, designing, operating, administering, and evaluating the DR programs through base rates. These rate case filing will also include any required tariff additions or modifications.

In the case of Maui Electric, this may include a RBDLC tariffed customer incentive payment beginning in 2016. It also will include a proposal to terminate Rider M in 2016, in order to encourage customers currently using Rider M to actively participate in the new market-based DR services programs available in 2016.

Subsequent general rate case filings by Hawai'i Electric Light Company and Hawaiian Electric would contain similar tariff additions and modifications.

Annual DR Program Filings

The Companies will continue to file Modification and Evaluation (M&E) and Accomplishments and Surcharge (A&S) reports annually for the new Integrated DR Portfolio. The reports will specifically address performance against key DR objectives addressed in this IDRPP. Costs and benefits will be evaluated for the individual programs and for the Integrated DR Portfolio as a whole.

EXPEDITE MAUI CAPACITY PROCUREMENT

In light of the immediate capacity needs of the Maui Electric system, the Companies will fast track the procurement process for those DR resources to provide capacity on Maui. To do so, the Companies expect to start the procurement process sooner and will focus on achieving near term impacts, "quick wins", including any customers with larger load resources that could be harnessed for DR relatively quickly once terms can be reached. Evaluation of the COM DWS and WWRD DR potential indicates the possibility of incorporating their emergency stand-by generation into a DR program.

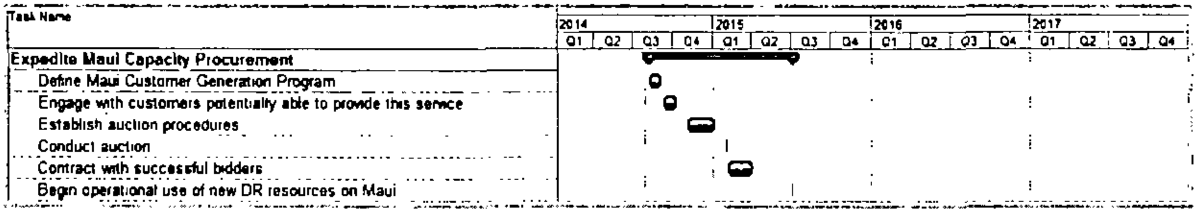

Figure 20. Implementation schedule for expediting Maui Capacity Procurement

ADJUST EXISTING DR PROGRAM PORTFOLIO FOR 2015

For 2015, the Companies plan to sustain the O'ahu RDLC program, after combining it with the Small Business DLC program and changing the program name to RBDLC. This program delivers the most value to customers at its present level, and it will continue to use its existing communications and control technology in the near term. The Companies propose to modify the existing CIDLC program for 2015 by merging the Fast DR and CIDLC commercial participants into a single unified technology platform using the existing standards based operational systems. The Companies intend to modify the payment structure and program rules for the participation of stand-by generator capacity service, and will propose a reduced customer incentive payment consistent with this reduced service.

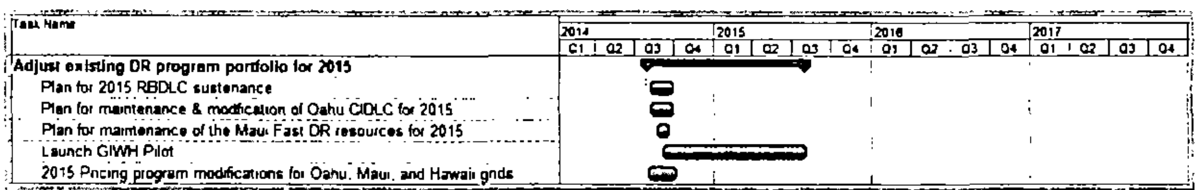

Figure 21. Implementation schedule for adjusting existing DR portfolio for 2015

Plan for Maintenance of the O'ahu RDLC (renamed RBDLC) Through 2015

Hawaiian Electric is currently developing plans to sustain the operation of the current RDLC program (new RBDLC) for 2015. The 2015 operation of this program will continue to rely on the legacy one-way paging communications system and the existing control switches, while aligning the planned upgrade of the switches to coincide with the proposed expansion of the program in 2016. The continued operation of the program in maintenance mode will provide approximately 10 MW of on-peak capacity to the system, as is the case in 2014. This DR capacity is routinely used by the system operator as a cost effective tool to meet system peaks, respond to generator trip events, and as a way to dampen ramp rates during periods of rapid load ramping. Hawaiian Electric plans to maintain the customer incentive at the current level.

Plan for Maintenance and Modification of the O'ahu CIDLC Program for 2015

Hawaiian Electric is currently completing the Fast DR Pilot program and intends to merge the program participants with the existing CIDLC program starting in 2015. The merged program will be available for C&I customers who can provide grid service requirements, including capacity, that meet the previously described requirements for response speed and response duration. Customers that do not meet the specifications of a given grid service requirement will be removed from the program. The capacity service provided by DR resources may be used no more than 100 hours per year and thus is limited by environmental permit requirements (RICE NESHAP) for generator participation in DR programs. Updates to the existing CIDLC program will be requested within 60-days after this filing.

In recognition of the cost avoidance being provided by the C&I customers, a reduced customer incentive payment will be proposed by 2015. This will result in the ability to fund the desired transition of the Fast DR program participants through 2015 and includes the consolidation of the operational systems and upgrades, allowing loads to be bid-ready for the planned DR auction.

The SBDLC sub-program within the CIDLC, uses direct load control of water heater, air conditioning, and other similar equipment from small business users to provide demand response. In practice, this program is substantially the same as the existing RDLC program. The Companies will propose to merge this sub-program into the RDLC program for 2015 and beyond, and call it RBDLC (see Chapter 4, "DR Program Evaluation and Redesign Considerations").

The planned transition of the CIDLC program will also include customer engagement activities to explain directly to customers what is happening for 2015, why it is happening, and directionally what the new opportunities will be for demand response resources in 2016. This customer engagement task is critical, as these customers have a history of providing support to the O'ahu grid and Hawaiian Electric's desires to encourage these customers to become engaged in the new DR programs for 2016.

To this end, the Companies will offer to include each customer on a list of interested prospects. Customers on this list will be contacted by the Companies with details of how to either directly offer grid services based on DR resources to the Companies or to participate through a third party aggregator. The Companies plan to make this list of prospects available to all pre-qualified aggregators (with appropriate confidentiality safeguards) to assist them in their customer recruitment activities.

Plan for Maintenance of the Maui Fast DR resources for 2015

The Maui Fast DR customers and capacities will be maintained through 2015. Ongoing base program costs will be included in the Maui Electric 2015 test year costs, or another mechanism as appropriate. Maui Electric will seek to transition the four customers and their enrolled load resources, as appropriate, to the Maui CIDLC or C&I Flexible program when those programs commence in 2016.

Pricing Program Adjustments for 2015

While advanced pricing programs for all islands will be launched coincident with the implementation of the smart grid program, which the Companies have proposed to begin rolling out in 2016, there are adjustments to the existing rate programs that should be made, as discussed in Chapter 4.

The Companies plan to propose updates to these pricing programs on all islands for 2015, and have particular interest in establishing more appropriate on- and off-peak periods that better reflect the current needs of the grid on each island.

ESTABLISH NEW DR SERVICES, STANDARDS, AND OPERATIONAL PROTOCOLS

This IDRPP lays out a very aggressive vision for the use of Demand Response resources to meet a wide variety of grid service requirements. To make this vision a dependable, cost-effective reality, there are a myriad of definitions, business processes, standards, protocols, and other requirements to be defined, agreed, and implemented across the Companies, customers, third-party aggregators, and technology suppliers. On or before January 2015, this work stream will draft these detailed specifications, seek input from a wide spectrum of stakeholders, and work to finalize the details of the portfolio's DR programs.

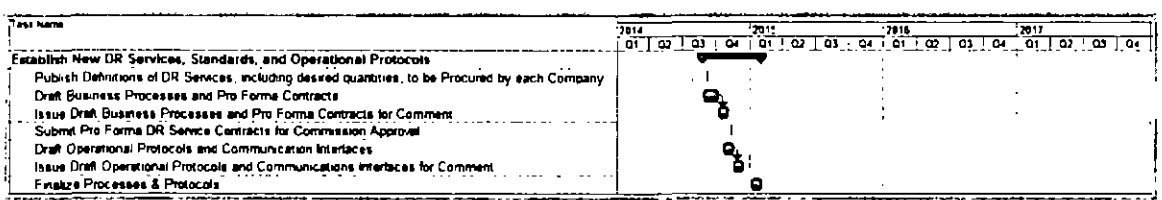

Figure 22. Implementation schedule for establishing new DR services, standards and operational protocols

Publish Desired Quantities of Each Specific Grid Service to be Procured by Island

In order to procure DR resources from the market, the market needs to understand the grid service requirements and the quantity of each services that the Companies will seek. Based in part on the results of the PSIPs for each Island, the Company will publish the proposed grid services to be acquired from DR resources, as well as the intended quantities of each for each Island in or about September, 2014.

Draft Business Processes and Pro Forma Contracts

The Companies expect to procure new Demand Response resources both directly from customers and through third party aggregators. Business processes will be developed to meet the enrollment, business operations, and termination requirements applicable to each resource provider. At a high level, the business process requirements will be based on the following delineation of responsibilities:

The DR resource provider, whether an end-use customer or an aggregator, would be required to:

- Inform the applicable company of which metering points will be used to provide the resource(s)
- Provide a secure communications link between System Operations and the resource that meets the response time requirements for the applicable service(s)

For DR resources provided by third party aggregators, the aggregators would:

- Perform end-use customer recruitment activities. The Companies may provide a list of end use customers interested in participating in DR programs to pre-qualified aggregators to assist in customer recruitment.
- Establish an exclusive business relationship with the end use customers providing the DR resources. An end-use customer may only enroll with a single third party provider at a time, and this relationship will be exclusively between the third party and the end use customer.

The Companies would:

- Provide overall branding of the DR programs and use the Companies' customer relationships to encourage program participation
- Pre-qualify all third party aggregators, so that the Companies can be assured that the aggregators are qualified, and that all customers can be assured of each aggregator's ability to meet the requirements of each grid service and to ensure that the customer realizes the benefit of its participation in a DR program;
- Maintain a register of all end-use meter locations enrolled as a DR resource

- Track the dispatch and use of each DR resource, provided by either an end-use customer or a third party aggregator
- Verify the performance of each DR resource and/or third party aggregator
- Provide a monthly accounting of the quantity of the DR grid services delivered, the purchase price for that grid service, and any performance penalties that may apply.
- Payment will be made by the Companies for DR resource providers monthly, one month in arrears, subject to future true-up for one year.

The DR resources and/or third party aggregators would each enter into a DR Resource Contract with the applicable company, codifying the commercial terms and conditions for the provision of respective grid services. The Companies plan to use a contract with standardized key provisions for procuring each of these grid services.

Seek External Comments on Draft Business Processes and Pro Forma Contracts

The insights and perspectives of potential providers of grid services by DR, as well as other interested parties, are critical to taking best advantage of the available DR resources for the benefit of all customers. To that end, the Companies would publish its draft Business Processes and its draft Pro Forma Contract for external comment. Based on the comments received, the Business Processes and Pro Forma Contracts will be revised as appropriate.

Apply for Commission Approval of Pro Forma Contracts

As indicated above, the Companies plans to use a standard contracting form for each grid service to be acquired by DR. Further, the price to be paid for each Service will be the price determined by the market-based processes (for example, "auction"). The Companies would apply for Commission approval of the key provisions of its Pro Forma Contract for each grid service provided by DR by the end of 2014.

Draft Operational Protocols and Communications Requirements

The Companies intend to administer the Demand Response resources from a centralized DR Operations team. This team will be the common business and administrative interface for DR providers on each island and will ensure that DR resources are enrolled in the appropriate program(s). This will populate each island's DRMS data base with the enrolled DR resources and provide System Operations with the available DR resources.

As shown in Figure 23 below, System Operations will define the daily grid operating needs, and the role the DR resources should play in meetings those needs.

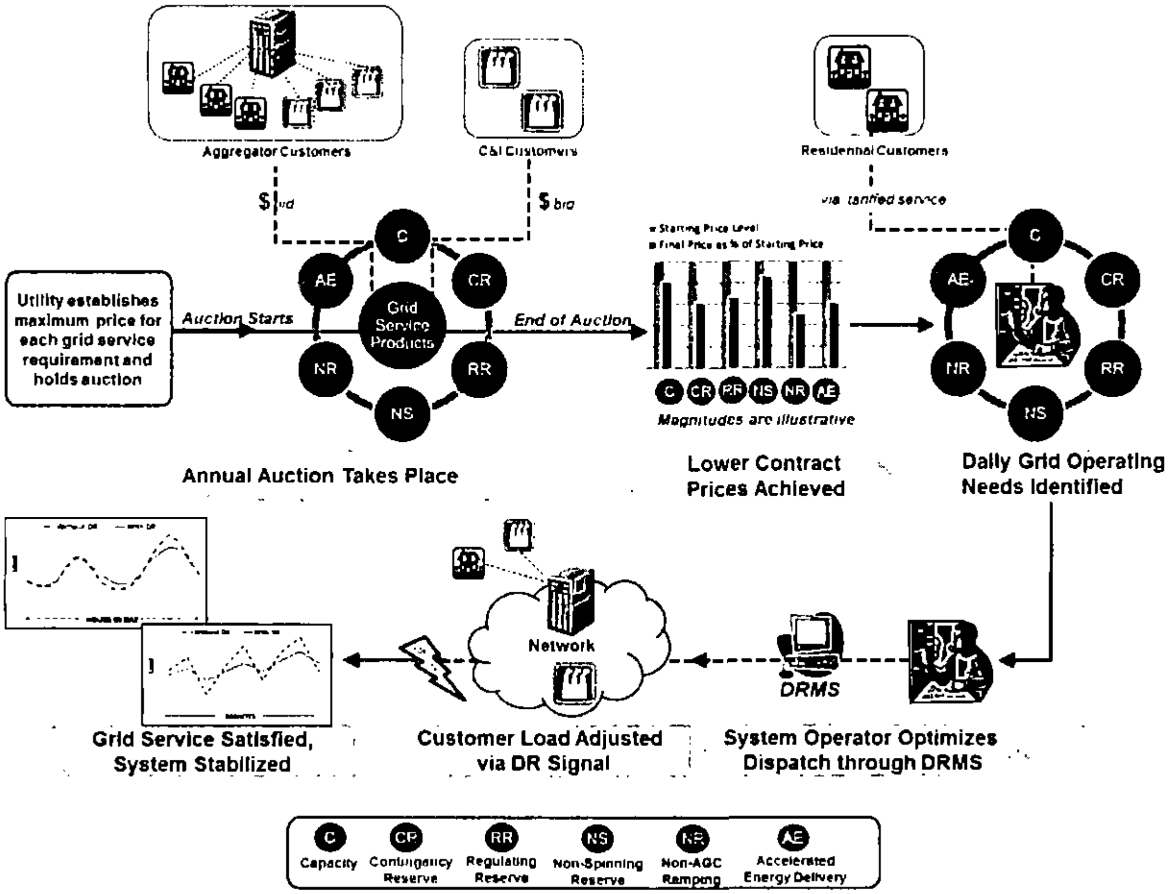

Figure 23. Overview of the IDRPP process to satisfy a grid service requirement

As the DR program matures, the operational cadence may be fully defined, along the following lines:

Week Ahead

- DR resources will notify the Companies weekly of any planned unavailability or limitation.

Day Ahead

- System Operations will issue a daily operating schedule by hour before 9 am on the Day before (Day -1).
- By noon on Day -1, each DR provider will confirm the specific meter service points it intends to use to provide the scheduled DR.
- Companies will determine any schedule adjustments required due to resource shortfalls by a DR provider and will issue a revised day-ahead schedule by 4 pm on Day -1.
- Planned Critical Peak Pricing events, if any, will be communicated to participants by 4pm on Day -1.

Real Time

- Companies will use least cost dispatch of scheduled DR resources as necessary to satisfy all system security and reliability standards.
- System Operations will monitor the real time delivery performance of each DR service dispatched.

Performance Evaluation and Settlement

- For any hour or fraction thereof in which a DR provider is dispatched at a level at or below the day ahead scheduled quantity and fails to deliver this quantity, a penalty equal to the greater of the cost of the undelivered service at the service's auction clearing price or the cost of the replacement resource used by System Operations to provide the undelivered service shall be assessed.
- DR service providers will be paid monthly, on or about the 20th of the following month, for the quantity of each service scheduled and delivered in the prior month, based on the auction clearing price for each service, less any applicable penalties.
- For RBDLC customers, the Companies will provide on-bill credit for program participation, as directed by their aggregator.

As can be seen from the above preliminary cadence, there will be numerous daily operational communications exchanges between the Companies and each DR provider. In addition, there are communications requirements between the Companies' System Operations centers and the actual end use meter points providing the DR resources. Standard specifications for each of these communications requirements will be developed.

Seek External Comments on Operational Protocols and Communications Requirements

The insights and perspectives of potential providers of DR grid services, as well as other interested parties, are critical to taking best advantage of the available DR resources for the benefit of all customers. To that end, the Companies will publish its draft Operational Protocols and its draft Communications Requirements in the fourth quarter of 2014 for external comment by interested stakeholders.

Finalize Business Processes, Operational Protocols and Communications Requirements

Based on the comments received from external stakeholders, the Company plans to finalize the business process design, operational protocols, and communications requirements by the end of January 2015. This will inform the selection of software tools to support these processes and protocols, which will be proceeding in parallel.

MARKET-BASED PROCUREMENT PROCESS

The Companies intend to use a market-based procurement process to acquire DR resources at the best possible price. One possible process would be an auction-based pricing process to determine the market price for DR programs, thereby attaining the best value for customers. In the discussion below, a draft process description is presented for consideration.

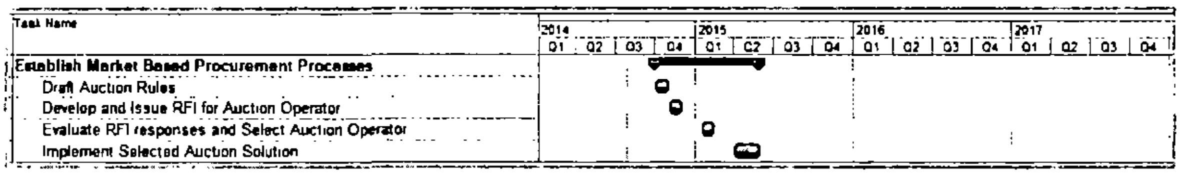

Figure 24. Implementation schedule for establishing market based procurement processes

Design Auction Process

The Companies would design an auction process, specifying requirements for how auctions will be conducted for each grid service to be acquired, and for each duration period. This would include qualified starting bids, minimum bid decrements, the duration of the auction, and the quantity selection process.

This process would also specify issues such as:

- Periodicity of Auctions - Plans call for annual auctions, for service to be provided beginning six months after the auction process is finalized.
- Standard Term of Offer - three year forward commitment by resources, with fixed pricing over the three year term. However, there may be situations where this term will be shorter for certain grid services.
- The first two auctions would have a portfolio of contract term lengths, as follows:
  - First auction – 1/3 of desired quantity of each service will be offered a one-year commitment, 1/3 a two-year commitment, and 1/3 a three-year commitment (starting bid price levels will differ for each contract length).
  - Second auction – ½ of the desired quantity of each service will be offered a one-year commitment, and ½ will be offer a three-year commitment (starting bid price levels will differ for each contract length).

Prepare and Issue an RFI for Auction Operator

The Companies would use an auction operator to conduct the periodic auctions for acquisition of DR grid services. A Request for Information (RFI) will be prepared and issued to potential providers of these auction services.

Evaluate RFI Responses and Select Auction Operator

The Companies would evaluate the RFI responses, select an operator and negotiate a contract for auction services. While the length of this contract would be informed, by the responses of the potential auction operators, the Companies hope is that this contract would cover a period of several years, providing consistency to the DR market participants.

Implement Selected Auction Solution

The Companies will work with the selected auction operator to implement and test their auction process as soon as practical, subject to the Commission's approval.

PROCURE DR RESOURCES

The procurement of DR programs from pre-qualified end-use customers and third party aggregators could be done through a reverse auction process, so as to achieve the best market price for each grid service.

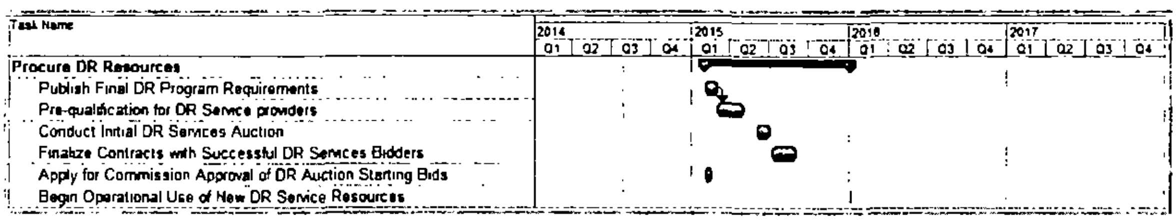

Figure 25. Implementation schedule for procuring DR resources

Publish Final DR Program Requirements for 2016 through 2018

The Companies would make a determination of the amounts of each grid service requirement over the period 2016 through 2018 for each island. These indicative quantities, as well as the final specifications for each grid service requirement, would be published in early 2015. In addition, the business processes, operational protocols, communications requirements, pro forma contracts, and auction rules will also be made available at the same time.

Apply for Commission Approval of Auction Starting Bids

If the auction process is utilized, it would require an appropriate starting bid, or an established reserve price, to ensure that the auction result is acceptable. For the DR Program auction to procure DR resources to provide a grid service, the Companies would determine the starting bid for each grid service. This starting bid price would be determined through an analysis of the cost of equivalent alternatives or avoided costs, less program administration costs.

The Companies would confidentially file its proposed auction reserve prices (maximum bids in this reverse auction), along with its supporting analysis, for Commission approval. The Companies would file for Commission approval approximately three months prior to the date of the auction.

Pre-Qualification of DR Program Providers

The Companies would establish required business qualifications for participation in the DR market. These would likely differ between end-use customers participating directly and third party aggregators. Potential market participants will be required to apply to the Companies, demonstrating that they meet the required business qualifications, to participate in the market.

Pre-qualified third party aggregators will be authorized to operate under the Companies' DR program, to assist with lead generation and alleviate customer concerns.

For third party aggregators, required business qualifications may likely include:

- Proof of credit worthiness
- Proof of license to do business in Hawai'i or equivalent
- Proof of good company standing
- Proof of delivering such services in other markets

Conduct Initial DR Program Auctions

The initial auctions for DR programs would be conducted as early as mid-2015, for services to be delivered starting January 1, 2016, or sooner. Participation would be open to any pre-qualified end-use customer or third-party aggregator.

The Companies may use an outside auction service to conduct these auctions.

Finalize Contracts with Successful Bidders

Based on the auction results, the Companies would offer standard contracts for each grid service provided by DR to the successful bidders. The Companies would expect to have contracts for grid services acquired by this method fully executed within 60 days following the auction.

GROWING THE RBDLC PROGRAM

The O'ahu RDLC –new RBDLC- program delivers valuable grid services that are regularly used by System Operations. However, this program is in need of a technology refresh and needs to be marketed aggressively to residential customers that are not currently subscribers in order to expand the scale of the grid services it can provide. Further, parallel programs should be launched on Maui and Hawai'i Islands.

To apply the IDRPP's principles of "deferring to the market" and "leveraging expert resources" to this program, the Companies will encourage pre-qualified third party aggregators to bid to provide grid services based on aggregated groups of new users. As indicated above, aggregators will be able to operate under the Companies' DR brand, while differentiating their services through their choices in control technology, communications technology, and financial incentives.

Informed by the number of aggregator applications, the number of pre-qualified aggregators, and ultimately the auction bids based on residential and small business load resources, the Companies will determine an appropriate migration path for the 30,000+ customers currently enrolled in the RBDLC. Alternatives could include offering the existing enrollees the choice of third party aggregators or possible continued Company administration by the Companies of a RBDLC program past 2015. It is anticipated that these options will be differentiated by control technology, communications technology, and customer incentive terms.

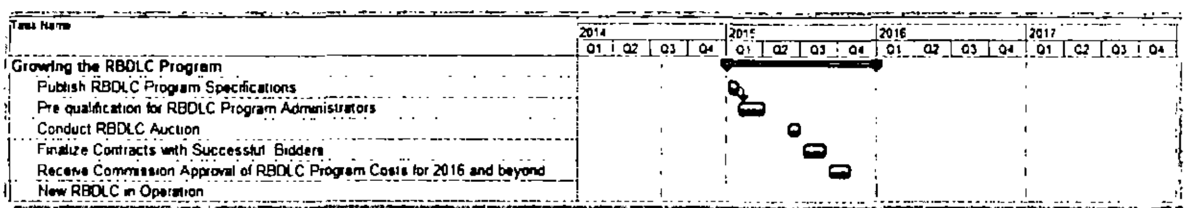

Figure 26. Implementation schedule for growing the RBDLC program

ESTABLISH CENTRALIZED DEMAND RESOURCES ORGANIZATION

The size, scale, and sophistication of the DR portfolio presented in this plan has never previously been contemplated by the Companies. To successfully implement the IDRPP, the Companies would require philosophical, managerial, financial, and resource commitments to DR that are aggressive and differ from the Companies' past DR posture and accomplishments. To meet this challenge, the Companies plan to centralize the DR activities of the Hawaiian Electric Company in a dedicated department, placed in the organization so as to ensure significant senior management support. Based on O'ahu, the new Demand Resources Department would be responsible for the planning, design, administration, and reporting activities associated with the Demand Response programs. This Department will also be responsible for the information systems that will enable the seamless enrollment, commitment, dispatch, verification, and payment for DR resources. Operating responsibility of the DR programs would remain with the System Operators of each utility.

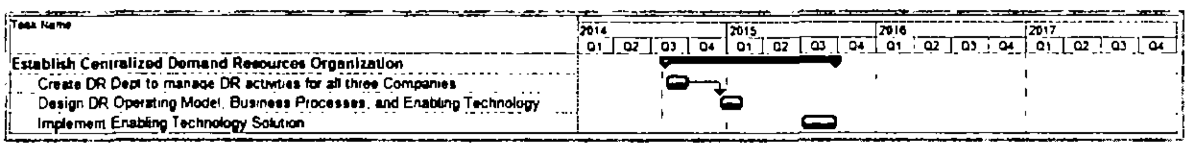

Figure 27. Implementation schedule for establishing Demand Resource Department

Create Demand Resource Department

The Demand Resources Department, serving all three companies, would be created within Hawaiian Electric, and headed by a new Department Manager. This would ensure it is in close organizational proximity to System Operations, its primary internal customer. The Department Manager would have primary responsibility for the program administration and management of the integrated DR portfolio.

The Demand Resources Department will be organized for maximum efficiency, and with an emphasis on building effective and cost-efficient DR programs as soon as practical. The DR Department Manager would report directly to the Vice President for Corporate Planning and Business Development. On a preliminary basis, the new department is expected to have four divisions, with each division headed by a division director reporting to the department manager:

- DR Operations Communications & Technology Division
- DR Commercial Operations Division
- DR Advanced Technology Research Division
- DR Operations and Administration

The permanent staff for the DR Department will be developed in the immediate future. Each operating company will also have dedicated DR personnel who would work cooperatively on a "matrix basis" with counterparts in the new DR Department.

The Company will begin the selection and placement process for these positions immediately.

Design DR Operating Model, Business Processes, and Enabling Technology

To efficiently execute this plan, an entirely new operating model and supporting business processes are required for the DR Department.

For example, this operating model would reflect incorporation of administration of contracts for procured DR resources, protocols for deploying DR resources in a market environment, monitoring DR resource performance metrics, and managing information technology infrastructure, among other things.

ESTABLISH VARIABLE PRICING PROGRAMS

The implementation of new, advanced pricing programs is dependent on the Companies smart grid program that is planned to be implemented over the next three to four years. The DR pricing programs for residential and small commercial customers, namely RBDLC, in particular, will leverage the smart grid AMI system.

Dynamic and Critical Peak Pricing programs will be employed, and the directional impacts and expected customer response will also be similar, but the details will certainly need to be adjusted over the next twelve months. One reason for this is that the degree of customer response desired will depend upon a number of factors, many of which will depend on information that emerges from the PSIP and DGIP analyses. For example, the increasing concentration of solar distributed generation will strongly influence the desired response from any pricing program – the lower the daytime minimum load (as driven by behind-the-meter PV), the more critical the need to increase midday consumption. These types of changes stand to influence the hours affected (for example is the desired load shift into the off-peak overnight hours only, or does it include midday hours as well) as well as price differentials. The more urgent the need to shift load on a daily basis, the greater the price differential between on- and off-peak prices.

Another consideration will be the urgency associated with capacity needs. Standard TOU programs tend hit the middle of the annual load duration curve effectively, but are not as effective in reducing system peaks because customers do not mind paying on-peak prices when they really want the power. In order to reduce peak load, critical peak pricing events are much more effective.

As more information emerges from the PSIP and DGIP analyses, and as the capacity need dates and magnitudes grow clearer on O'ahu and especially Maui, the programs will be revised accordingly. Other variables that could impact pricing programs include the smart grid implementation schedule, elasticity changes that change the assumptions behind preserving revenue neutrality, and generation build plan adjustments or load shape impacts.

The Companies understand that tariff changes will be required to implement these types of pricing changes and will be proposing these in rate case or other appropriate forums. The Company also plans to withdraw its pending application for a Commercial & Industrial Dynamic Pricing pilot.[71]

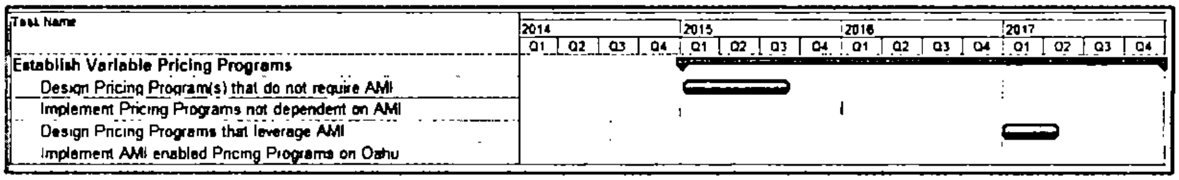

Figure 28. Implementation schedule for establishing variable pricing programs

[71] See Docket 2011-0392 filed 12/29/2011.

APPENDICES

A. Use of Demand Response for Ancillary Services in Other Jurisdictions

PJM	Demand response is an integral part of PJM's markets, and currently there are three ancillary service markets in which demand response resources can participate: day-ahead scheduling reserves,[1] synchronized reserve[2] and regulation[3]. PJM has taken a number of steps to minimize market barriers for potential demand response resources, such as implementing market rule changes that reduced minimum size requirement for regulation resources, and developing compensation mechanisms for both capability and performance. Allowing aggregation of demand response has also helped to achieve high participation rates. On the other hand, a symmetric bid[4] requirement for the regulation market may keep some potential demand response resources out of the market, because most loads are more capable of reducing load than increasing it. In the first months of 2014, synchronized reserves capability coming from demand response averaged 363 MW.[5] Similarly, for the same time period, demand response regulation capability was recorded as 8.3 MW on average.[6]
ERCOT	There are two types of loads defined in ERCOT's demand response market: non-controllable load resources (NCLR) and controllable load resources (CLR). NCLRs can be deployed either through automatic trip based on under-frequency relay settings, or by verbal dispatch during emergency conditions. CLRs mostly include energy storage technologies. Both NCLRs and CLRs are comprised of industrial loads and participate in ancillary service markets for regulating reserve and contingency reserve (referred to as Responsive Reserve Service). For under-frequency related contingency reserve, load resources are limited to 50% of the total Responsive Reserve Service, and as of 2014, there are 217 load resources providing 2,900 MW.[7] For governor-type (droop) frequency related contingency service, the participation has been very limited. A non-spinning reserve service is scheduled to be available through CLRs within 2014, which will include aggregated commercial and residential loads.
New Zealand	New Zealand has an isolated power system, with roughly 6,500 MW of daily peak. In addition to well-established capacity and energy demand response programs, there are a number of existing and developing initiatives focused on ancillary services. Currently, most demand response programs are incentive based, but deployment of smart meters may lead to significant adoption of price-based programs as well. An Interruptible Load (IL) program offers ancillary services in the form of Instantaneous Reserve (supports the grid system frequency) and Spinning Reserve. IL is provided by industrial and commercial end-users, usually via an aggregator.[8] In monetary terms, the Instantaneous Reserve represents at most 3% of the energy market, but it is essential for covering the security risk associated with the supply of energy.[9] Demand response also provides load shifting services during peak periods through a form of Direct Load Control program. This program, referred to as ripple control, has been utilized successfully at the distribution and retail level for many decades to shed household water heating load.

[1] The ability to reduce electricity consumption within 10 minutes of PJM dispatch, as defined PJM Demand Response Fact Sheet for End-Use Customers, can be accessed at http://www.pjm.com/~/media/markets-ops/dsr/end-use-customer-fact-sheet.ashx

[2] The ability to reduce electricity consumption within 30 minutes of PJM dispatch, Ibid.

[3] The ability to follow PJM's regulation and frequency response signal, Ibid.

[4] Requirement to provide both up and down regulation.

[5] PJM 2014 Demand Response Operations Markets Activity Report: June 2014.

[6] Ibid.

[7] Demand Response in ERCOT, 2014 Operations Training Seminar.

[8] EnerNOC Inc. provides aggregation services under the DemandSMART NZ Interruptible Load Program.

[9] The wholesale energy market traded $2.1 billion worth of electricity in the year to July 2011 (source http://www.ea.govt.nz/consumers/how-the-electricity-market-works, accessed in July 2014). The cost of procuring Instantaneous Reserve in the reserves markets was $66.2 million in 2007 and $21.9 million in 2010 (source: http://www.ea.govt.nz/code-and-compliance/the-code/historical-versions-of-the-code/documents-incorporated-by-reference, accessed in July 2014).

Table A 1. Use of Demand Response for Ancillary Services in Other Jurisdictions

B. Estimation of Demand Response Potential

The following first presents which grid service requirements are satisfied by which DR programs, and which resources are included under each DR program. Then, the assumptions behind the DR potential for each resource are detailed for all the three islands. Even though these projections are based on a number of informed assumptions supported by data and analyses, the Companies believe that ultimate resource availability will be determined by the market.

MAPPING OF RESOURCES TO PROGRAMS AND GRID SERVICE REQUIREMENTS

Table B 1 shows the mapping of the resources to the programs and grid services, assessed by the Companies given the best available information on the market and technology.

Program	Grid Service Requirement	Resource
RBDLC	Capacity	Water Heaters, central A/C
	Non-AGC Ramping	Water Heaters, central A/C
	Non Spinning Reserve	Water Heaters, central A/C
R&B Flexible	Regulating Reserve	GIWH, central A/C
	Accelerated Energy Delivery	GIWH
CIDLC	Capacity	C&I Curtailable
C&I Flexible	Regulating Reserve	Central A/C, Ventilation, Refrigeration
	Non-AGC Ramping	Central A/C, Ventilation, Refrigeration, Lighting
Water Pumping	Regulating Reserve	Pumps
	Non-AGC Ramping	Pumps
Customer Firm Generation	Capacity	Generators
Dynamic and Critical Peak Pricing	Capacity	Unspecified Customer Load
	Accelerated Energy Delivery	Unspecified Customer Load

Table B 1. Programs, grid services and load resources considered in the integrated portfolio

GENERAL ASSUMPTIONS

Table B 2 and Table B 3 contain the percentage contribution to peak demand by the three main customer classes, and net peak demand characteristics of the three islands in the coming years, respectively.

	Residential	Commercial	Industrial
O'ahu	32%	61%	6%
Hawai'i	55%	39%	4%
Maui	41%	52%	5%

Table B 2. Estimated contribution to peak demand by customer class[72]

	2014	2019	2024
O'ahu	1,173	1,238	1,193
Hawai'i	191	193	198
Maui	194	214	218

Table B 3. Net peak demand by island (MW)

[72] Values may not add up to 100% due to rounding.

ASSUMPTIONS FOR PROGRAMS AND LOAD RESOURCES

Residential and Small Business Direct Load Control (RBDLC)

For all islands, RBDLC program consists of water heating and central A/C programs.

Table B 4 shows the estimated DR potential for RBDLC on each island between 2014 and 2020.[73] DR potentials in the years following 2020 stay the same. The assumption is that while capacity figures might fall due to declining peaks or attrition, that negative impact will be offset by the positive impact of other factors such as new DLC programs for new appliances, or new customer recruitment programs.

	2014	2015	2016	2017	2018	2019	2020
O'ahu	16.0	18.9	21.8	24.7	27.5	30.4	33.3
Hawai'i	0.0	0.3	1.4	2.6	3.7	4.9	6.0
Maui	0.0	0.3	1.7	3.0	4.4	5.7	7.1

Table B 4. RBDLC DR potential estimates (MW)

Details for each island are provided below.

O'ahu

O'ahu's 2014 RDLC estimate is based on the Adequacy of Supply (AOS) report of Hawaiian Electric Company, filed on April 2014 (referred to as "Hawaiian Electric AOS 2014" in the remainder of the document).[74] 2020 figure is based on the estimate in the Assessment of Demand Response Potential for HECO, HELCO and MECO report, prepared by Global Energy Partners (GEP) and submitted in May 2010 (referred to as "GEP 2010" in the remainder of the document). Estimates for 2015-2019 were obtained by interpolating between the 2014 and 2020 figures.

Hawai'i

As of 2014, there is no RDLC program on Hawai'i. It is estimated that the island will add 5.3 MW of RWH and 0.7 MW RAC under its proposed RDLC program by 2033.[75] In this analysis, an accelerated schedule for the program is assumed where the 2033 goals will

[73] Values on the table reflect an assessment based on the current RDLC program. RBDLC program proposed in the IDRPP combines RDLC with SBDLC, which currently has 1 MW of DR capacity. Therefore, it is expected that once RBDLC is in effect, these values will be slightly higher to account for the addition of participants in the current SBDLC program.

[74] See page 11 in the AOS.

[75] See Appendix F, Table F-14 and Table F-15 of the Integrated Resource Planning.

be achieved by 2020, and the program will kick off with 0.3 MW of demand response in 2015. Estimates for 2016-2019 were obtained by interpolating between the 2015 and 2020 figures.

Maui

As of 2014, there is no RDLC program on Maui. Based on IRP 2013, it is estimated that the island will add 6.2 MW of RWH and 0.9 MW RAC under its proposed RDLC program.[76] In this analysis, an accelerated schedule for the program is assumed where the 2033 goals will be achieved by 2020, and the program will kick off with 0.3 MW of demand response in 2015. Estimates for 2016-2019 were obtained by interpolating between the 2015 and 2020 figures.

Residential and Small Business A/C

This program is considered separately from the previously described RBDLC program (even though the RBDLC program contains an A/C program), because it is also proposed as a future Regulating Reserve source in addition to being a DLC resource. Therefore, the yearly estimates of A/C in this category may not necessarily be the same with the A/C component under the RBDLC program.

Within the A/C DR program, current participants are predominantly residential customers. Therefore the DR potential estimation is primarily based on the residential A/C assessment. However, once the proposed program replaces the current RDLC program, DR potential numbers represented here will be slightly higher due to the addition of small business A/C DR capacity.

Based on the most recent Class Load Studies completed for O'ahu, Hawai'i and Maui (referred to as "CLSs" for the remainder of the document), contribution of the residential class to peak demand is 32%, 55% and 41%, respectively (see Table B 2). In addition, Energy Efficiency Potential Study completed for Hawaiian Electric by the Global Energy Partners in 2008 (referred to as "GEP 2008" in the remainder of the document) estimated that contribution of A/C to residential peak load is roughly 31% on O'ahu. Assuming that this proportion is similar for Hawai'i and Maui, and using the latest peak demand estimates for each island (see Table B 3), contribution of residential A/C to peak demand can be approximated for each island.

In addition, it is further assumed that up to 10% of the A/C load can be controlled both up and down (10% down and 10% up), and that by 2022, up to 20% of the total A/C load on each island will participate in the program, with a linear increase from 0% in 2014.

[76] See Appendix F, Table F-10 and Table F-11 of the Integrated Resource Planning.

Based on the assumptions above, residential and small business A/C DR potential estimates for each island are given in Table B 5. From 2022 onwards, estimates are assumed to stay flat.

	2014	2015	2016	2017	2018	2019	2020	2021	2022
O'ahu	0.0	0.3	0.6	0.9	1.2	1.5	1.8	2.1	2.4
Hawai'i	0.0	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.7
Maui	0.0	0.1	0.1	0.2	0.3	0.3	0.4	0.5	0.5

Table B 5. Residential and small business A/C DR potential estimates (MW)

Commercial & Industrial Direct Load Control (CIDLC)

DR potential coming from the existing CIDLC program is summarized by island in Table B 6 through 2020. Estimates following 2020 are assumed to be the same with 2020 and remain flat thereafter. Further details for each island's figures are provided in the following subsections.

	2014	2015	2016	2017	2018	2019	2020
O'ahu	16.0	17.6	19.1	20.7	22.3	23.8	25.4
Hawai'i	0.0	0.2	0.6	1.0	1.4	1.8	2.2
Maui	0.2	0.7	1.1	1.6	2.1	2.5	3.0

Table B 6. CIDLC DR potential estimates (MW)[77]

O'ahu

O'ahu's 2014 number is based on Hawaiian Electric AOS 2014 – 14 MW under CIDLC program and 2 MW under Fast DR program. The 2020 estimate is based on the GEP 2010 report – 23 MW under C&I Curtailable and 2.4 MW under CIDLC.[78] Estimates for 2015-2019 were obtained by interpolating between the 2014 and 2020 figures.

Hawai'i

As of 2014, Hawai'i does not have a CIDLC program. Based on the 2010 GEP report, it is expected to have 2.2 MW of CIDLC resources by 2020.[79] In this analysis, the program is

[77] Once the RBDLC program proposed in this IDRPP is in effect, the numbers represented here will be slightly lower due to the migration of the SBDLC capacity into the RBDLC program. Currently, SBDLC program has approximately 1 MW of capacity.

[78] See Table ES-5 in the GEP report, the sum of C&I Direct Load Control and C&I Curtailable.

[79] See Table ES-6, the sum of C&I Direct Load Control and C&I Curtailable.

assumed to kick off in 2015 with 0.2 MW of DR. Estimates for 2016-2019 were obtained by interpolating between the 2015 and 2020 figures.

Maui

Maui currently has a pilot Fast DR program with 200 KW installed capacity. Based on the 2010 GEP report, it is expected to have 3.0 MW of CIDLC resources by 2020.[80] Estimates for 2015-2019 were obtained by interpolating between the 2014 and 2020 figures.

Commercial A/C

For this analysis, only the A/C load coming from the commercial class is considered, because A/C load coming from the industrial sector is negligible.

Based on the CLSs and the GEP 2008 report, contribution of the commercial class to peak demand is 61%, 39% and 52% for O'ahu, Hawai'i and Maui, respectively. In addition, the 2008 GEP study estimated that contribution of A/C to commercial peak load is roughly 17% on O'ahu. Assuming that this proportion is similar for Hawai'i and Maui, and using the latest peak demand estimates for each island, contribution of commercial A/C to peak demand can be approximated for each island.

It is further assumed that up to 10% of the commercial A/C load can be controlled both up and down (10% down and 10% up), and that by 2022, up to 20% of the total A/C load on each island will participate in the program, with a linear increase from 0% in 2014.

Based on the assumptions above, Commercial A/C DR potential estimates for each island are given in Table B 7. From 2022 onwards, estimates are assumed to stay flat.

	2014	2015	2016	2017	2018	2019	2020	2021	2022
O'ahu	0.0	0.3	0.6	1.0	1.3	1.6	1.9	2.2	2.5
Hawai'i	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3
Maui	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4

Table B 7. Commercial A/C DR potential estimates (MW)

Commercial & Industrial Venting

For this analysis, only the ventilation load coming from the commercial class is considered, because ventilation load coming from the industrial sector is negligible.

[80] See Table ES-7, the sum of C&I Direct Load Control and C&I Curtailable.

Based on the CLSs and the GEP 2008 report, contribution of the commercial class to peak demand is 61%, 39% and 52%, respectively (see Table B 2).[81] In addition, the 2008 GEP study estimated that contribution of ventilation to commercial peak load is roughly 7% on O'ahu. Assuming that this proportion is similar for Hawai'i and Maui, and using the latest peak demand estimates for each island, contribution of commercial ventilation to peak demand can be approximated for each island.

It is further assumed that up to 10% of the commercial ventilation load can be controlled both up and down (10% down and 10% up), and that by 2022, up to 20% of the total ventilation load on each island will participate in the program, with a linear increase from 0% in 2014.

Based on the assumptions above, ventilation DR potential estimates for each island are given in Table B 8. From 2022 onwards, estimates are assumed to stay flat.

	2014	2015	2016	2017	2018	2019	2020	2021	2022
O'ahu	0.0	0.1	0.3	0.4	0.6	0.7	0.8	1.0	1.1
Hawai'i	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Maui	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2

Table B 8. Ventilation DR potential estimates (MW)

Commercial & Industrial Lighting

For this analysis, only the lighting load coming from the commercial class is considered, because lighting load coming from the industrial sector is negligible.

Based on the CLSs and the GEP 2008 report, contribution of the commercial class to peak demand is 61%, 39% and 52%, respectively (see Table B 2).[82] In addition, the 2008 GEP study estimated that contribution of lighting to commercial peak load is roughly 45% on O'ahu. Assuming that this proportion is similar for Hawai'i and Maui, and using the latest peak demand estimates for each island, contribution of commercial lighting to peak demand can be approximated for each island.

It is further assumed that up to 10% of the commercial lighting load can be controlled both up and down (10% down and 10% up), and that by 2022, up to 30% of the total lighting load on each island will participate in the program, with a linear increase from 0% in 2014.

[81] Hawaiian Electric 2012 Class Load Study, Maui Electric 2009 Class Load Study, Hawai'i Electric Light 2008-2009 Class Load Study, 2008 Energy Efficiency Potential Study prepared by Global Energy Partners.

[82] Ibid.

Based on the assumptions above, commercial lighting DR potential estimates for each island are given in Table B 9. From 2022 onwards, estimates are assumed to stay flat.

	2014	2015	2016	2017	2018	2019	2020	2021	2022
O'ahu	0.0	1.2	2.5	3.8	5.1	6.4	7.6	8.8	10.0
Hawai'i	0.0	0.1	0.2	0.4	0.5	0.6	0.8	0.9	1.0
Maui	0.0	0.2	0.4	0.5	0.7	0.9	1.1	1.3	1.5

Table B 9. Lighting DR potential estimates (MW)

Commercial & Industrial Refrigeration

For this analysis, only the refrigeration load coming from the commercial class is considered for simplicity.

Based on the CLSs and the GEP 2008 report, contribution of the commercial class to peak demand is 61%, 39% and 52% for O'ahu, Hawai'i and Maui, respectively (see Table B 2).[83] In addition, the 2008 GEP study estimated that contribution of refrigeration to commercial peak load is roughly 3% on O'ahu. Assuming that this proportion is similar for Hawai'i and Maui, and using the latest peak demand estimates for each island, contribution of commercial lighting to peak demand can be approximated for each island.

It is further assumed that up to 10% of the commercial refrigeration load can be controlled both up and down (10% down and 10% up), and that by 2022, up to 20% of the total refrigeration load on each island will participate in the program, with a linear increase from 0% in 2014.

Based on the assumptions above, commercial refrigeration DR potential estimates for each island are given in Table B 10. From 2022 onwards, estimates are assumed to stay flat.

	2014	2015	2016	2017	2018	2019	2020	2021	2022
O'ahu	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5

[83] Ibid.

Hawai'i	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Maui	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1

Table B 10. Refrigeration DR potential estimates (MW)

C&I Water Pumping

For this analysis, only the pumping load coming from the industrial class is considered for simplicity.

Based on the CLSs and the GEP 2008 report, contribution of the industrial class to peak demand is 6%, 4% and 5%, respectively (see Table B 2).[84] In addition, the 2008 GEP study estimated that contribution of pumping to industrial peak load is roughly 51% on O'ahu. Assuming that this proportion is similar for Hawai'i and Maui, and using the latest peak demand estimates for each island, contribution of industrial pumping to peak demand can be approximated for each island.

It is further assumed that up to 10% of the industrial pumping load can be controlled both up and down (10% down and 10% up), and that by 2022, up to 50% of the total industrial pumping load on each island will participate in the program, with a linear increase from 0% in 2014.

Based on the assumptions above, industrial pumping DR potential estimates for each island are given in Table B 11. From 2022 onwards, estimates are assumed to stay flat.

	2014	2015	2016	2017	2018	2019	2020	2021	2022
O'ahu	0.0	0.2	0.5	0.7	0.9	1.2	1.4	1.7	1.9
Hawai'i	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2
Maui	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3

Table B 11. Pumping DR potential estimates (MW)

Grid Interactive Water Heating (GIWH)

For this analysis, only the residential class is considered.

Based on the CLSs and the GEP 2008 report, contribution of the residential class to peak demand is 32%, 55% and 41% on O'ahu, Hawai'i, and Maui, respectively (see Table B 2).[85] In addition, the 2008 GEP study estimated that contribution of water heating to

[84] Ibid.

[85] Ibid.

residential peak load is roughly 14% on O'ahu. Assuming that this proportion is similar for Hawai'i and Maui, and using the latest peak demand estimates for each island, contribution of water heating to peak demand can be approximated for each island.

It is further assumed that up to 100% of the water heating load in the program can be controlled both up and down (10% down and 10% up) via special control and communications systems, and that by 2022, up to 5% of the total residential water heating load on each island will participate in the GIWH program, with a linear increase from 0% in 2014.

Economic and especially regulatory economic hurdles must still be cleared, as discussed in Chapter 3. As a result of the prevailing regulatory risk, the Companies have been relatively conservative in their projections regarding GIWH. However, the Companies are very excited about the technology's ability to contribute to regulating reserve and accelerated energy delivery and will continue to pursue it aggressively.

Based on the assumptions above, GIWH DR potential estimates for each island are given in Table B 12. From 2022 onwards, estimates are assumed to stay flat.

	2014	2015	2016	2017	2018	2019	2020	2021	2022
O'ahu	0.0	0.3	0.7	1.0	1.4	1.7	2.1	2.4	2.7
Hawai'i	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.7
Maui	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.5	0.6

Table B 12. GIWH DR potential estimates (MW)

Customer Generation

This category includes customer-sited generators that can respond to capacity needs by the grid. Table B 13 summarizes the Customer Generation DR potential by island, by year. Once the DR potential estimated for 2016 is achieved, estimates in future years are assumed to remain flat.

	2014	2015	2016	2017	2018	2019	2020
O'ahu	0.0	0.0	5.0	5.0	5.0	5.0	5.0
Hawai'i	0.0	0.0	3.0	3.0	3.0	3.0	3.0
Maui	0.0	0.0	3.0	3.0	3.0	3.0	3.0

Table B 13. Customer Generation DR potential estimates (MW)

Detailed assumptions for each island are provided in the following subsections.

O'ahu

Based on a 2014 Customer Generator Site survey,[86] there is approximately 20 MW of customer generators ready to participate in new Hawaiian Electric DR programs with minor upgrades and permitting. It is assumed that roughly 15 MW of this potential is already participating in the CIDLC program, and therefore only 5 MW will be available under this program. It is also assumed that all the upgrades and permitting is completed by the end of 2015, and the equipment becomes operational with 5 MW starting from 2016. After 2016, the potential remains the same.

Hawai'i

Given lack of data for Hawai'i customer-sited generators, and the island's similar peak demand characteristics with that of Maui, its customer generator potential is assumed to be the same magnitude with Maui. Please see the next section for how Maui's potential was derived.

Maui

A recent Demand Response Feasibility for Water and Wastewater facilities in Maui determined that there is 6 MW of potential for customer-sited generators.[87] It is assumed that 50% of this total potential can receive the required permitting, and that these resources become operational starting from 2016. After 2016, the potential remains the same.

[86] Hawai'i Electric Companies Customer Generator Survey, prepared by IPKeys Technologies LLC in April 2014.

[87] Demand Response Feasibility Study Phase-1, MECO, Brown & Caldwell, 2014.

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Average Hourly Potential Availability by Program and Grid Service

Program	Grid Service	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Hour in the Day																							
RBDLC	Capacity	20%	15%	10%	20%	50%	50%	50%	55%	60%	55%	50%	40%	30%	30%	40%	50%	75%	75%	90%	100%	90%	80%	50%	40%
	Contingency Reserve																								
	Non AGC Ramping	20%	15%	10%	20%	50%	50%	50%	55%	60%	55%	50%	40%	30%	30%	40%	50%	75%	75%	90%	100%	90%	80%	50%	40%
	Non Spinning Reserve	20%	15%	10%	20%	50%	50%	50%	55%	60%	55%	50%	40%	30%	30%	40%	50%	75%	75%	90%	100%	90%	80%	50%	40%
R&B Flexibility	Regulating Reserve	77%	72%	72%	72%	72%	72%	72%	74%	79%	86%	91%	95%	100%	100%	100%	100%	100%	95%	91%	86%	81%	77%	77%	77%
	Accelerated Energy Delivery	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
CIDLC	Capacity	80%	80%	80%	80%	80%	80%	90%	90%	95%	95%	100%	100%	100%	100%	100%	95%	90%	90%	85%	85%	80%	80%	80%	80%
	Contingency Reserve																								
C&I Flexible	Regulating Reserve	80%	80%	80%	80%	80%	80%	90%	90%	95%	95%	100%	100%	100%	100%	100%	95%	90%	90%	85%	85%	80%	80%	80%	80%
	Non-AGC Ramping	59%	59%	59%	59%	59%	59%	62%	62%	63%	63%	65%	65%	65%	65%	65%	63%	62%	62%	96%	96%	94%	94%	59%	59%
C&I Pumping	Regulating Reserve	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	75%	50%	50%	50%	50%	50%	75%	100%	100%	100%	100%	100%	100%	100%
Customer Generation	Capacity	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table B 14. Average hourly potential availability by program and grid service

C. RATES OF SELECT SCHEDULES

HAWAIIAN ELECTRIC

Schedule J – General Service Demand	Effective Sep 1, 2012
Customer Charge	$60/mo for single-phase service, $82/mo three-phase service
Demand Charge	$11.69/kW-mo
Energy Charge	16.9734 cents/kWh

Schedule DS – Large Power Directly Served	Effective Sep 1, 2012
Customer Charge	$400/mo
Demand Charge	$21.00/kW-mo
Energy Charge	13.9223 cents/kWh

Schedule P – Large Power	Effective Sep 1, 2012
Customer Charge	$350/mo
Demand Charge	$24.34/kW-mo
Energy Charge	14.9013 cents/kWh

HAWAI'I ELECTRIC LIGHT

Schedule J – General Service Demand	Effective Apr 9, 2012
Customer Charge	$38/mo for single-phase service, $64/mo three-phase service
Demand Charge	$10.25/kW-mo
Energy Charge	24.8033 cents/kWh

Schedule P – Large Power Service	Effective Apr 9, 2012
Customer Charge	$400/mo
Demand Charge	$19.50/kW-mo
Energy Charge	21.8184 cents/kWh

MAUI ELECTRIC

Molokai Division

Schedule J – General Service Demand	Effective Aug 1, 2013
Customer Charge	$37/mo for single-phase service, $47/mo three-phase service
Demand Charge	$10.00/kW-mo
Energy Charge	36.9705 cents/kWh

Schedule P – Large Power Service	Effective Aug 1, 2013
Customer Charge	$150/mo
Demand Charge	$18.00/kW-mo
Energy Charge	29.5392 cents/kWh

Maui Division

Schedule J – General Service Demand	Effective Aug 1, 2013
Customer Charge	$60/mo for single-phase service, $75/mo for three-phase service
Demand Charge	$10.00/kW-mo
Energy Charge	30.4163 cents/kWh

Schedule P – Large Power Service	Effective Aug 1, 2013
Customer Charge	$300/mo
Demand Charge	$20.00/kW-mo
Energy Charge	27.7504 cents/kWh

Lanai Division

Schedule J – General Service Demand	Effective Aug 1, 2013
Customer Charge	$50/mo for single-phase service, $70/mo for three-phase service
Demand Charge	$11.50/kW-mo
Energy Charge	42.5860 cents/kWh

Schedule P – Large Power Service	Effective Aug 1, 2013
Customer Charge	$250/mo
Demand Charge	$22.00/kW-mo
Energy Charge	40.2141 cents/kWh