Gridworks Advanced Rate Design Working Group Report

Docket 2019-0323

GRIDWORKS

Hawaii Public Utilities Commission

Advanced Rate Design Working Group Report

Introduction

> *The Commission observes that the Company's rate design has not significantly changed for a number of years, and should be examined to account for the new realities facing the Company and its customers...Dynamic rate designs are critical to aligning customer behavior with grid needs to realize the full value of DER and to allow all customers opportunities to participate in the energy system. Such rate designs enable the Company to leverage investments in advanced metering infrastructure, telecommunications, and improved sensing and data functionalities, and other components of the Company's Grid Modernization Strategy.* (Order No. 37066 issued April 9, 2020, at page 14.)

This Working Group Report synthesizes the content shared in Advanced Rate Design (ARD) working group meetings, convened in the Distributed Energy Resources (DER) Docket 2019-0323. It is intended as a resource for Commission staff and stakeholders to track the dialogue, clarify data needs, and highlight considerations and recommendations for advanced rate design in Hawaii.

Gridworks served as a facilitator for this working group and holds editorial responsibility for the content of this report. Statements and opinions contained herein do not necessarily reflect the views of the Commission. Statements are not attributed to participants to maintain the confidence of the group.

Working Group Formation and Logistics

Commission Order 37066 called for a working group process within the ARD Track of the DER docket (2019-0323) to support the Parties in developing proposals for advanced rate design (e.g., time-differentiated pricing) consistent with the Commission's goals.[1] From August through October 2020, the

[1] The Commission identified the following broad objectives for the ARD Track: (1) Address challenges currently faced by low- and moderate-income ("LMI") customers and create new opportunities to facilitate customer equity; (2) Unbundle costs to facilitate a reasonable allocation of system costs among customers and to develop reasonable rates and charges; (3) Evaluate benefits and drawbacks of specific rate design options, such as minimum bills, fixed charges, variable charges, etc.; (4) Appropriately balance the objectives and properties for advanced rate designs discussed above; (5) Establish advanced rate designs including time-of-use ("TOU") rate options for residential and commercial customers; (6) Develop pilot programs to evaluate other advanced rate design options (e.g., subscription rates, real time pricing, etc.); and (7) Update electric vehicle ("EV") rate

ARD working group met virtually nine times in seven biweekly three-hour meetings and two supplemental one-hour meetings focused on data. Meeting topics included: cost classification, revenue apportionment, rate design options for C&I customers, rate design options for residential customers, rate design options for electric vehicle charging, surcharges, pilots, and marketing, education, and outreach.

In the first working group meeting, participants established the following Working Group Objectives:

1. Assist parties in developing quality proposals through:
    a. Dialogue and information sharing
    b. Shared learning about rate design approaches for Hawaii
    c. Collaboration on the development of ideas and specific rates
2. Action on near-term options for TOU rates to pair with programmatic options (e.g., water heaters, demand response, low- and medium-income customers)
3. Modifications to demand charges
4. Better understanding cost of service studies and the relationship to advanced rate design
5. Clarification of the opportunities to unbundle revenue requirement costs to better inform rate design

Basics of Unbundling and Allocating Costs of Electric Service

In filed comments, some Parties have called for the need to "unbundle" electric rates to better align costs with services provided to customers. However, other Parties have noted that the term "unbundling" is ambiguous and has different meanings for different parties. Therefore, the first working group meeting sought to clarify common terms and approaches in rate design. Strategen Consulting presented *ARD Common Terms and Approaches* to establish a shared understanding of the terminology and methods that would be used in the working group moving forward. In this presentation, the term "unbundle" was described as pricing each utility-provided service separately rather than as a part of a package to improve cost transparency and allocation, improve price signals to customers, and inform resource procurement. This concept can be applied to rate design, cost of service studies, or resource procurement processes.[2] Costs (i.e., revenue requirements) may be unbundled to inform rate design

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structures (e.g., residential and commercial EV, EV-Bus, Fast EV charging) to incorporate lessons learned and to improve the effectiveness of the rate options.

[2] Strategen, 2020, ARD Common Terms and Approaches presentation, shared August 5, 2020.

but prices (i.e., costs for individual electric grid services) could remain bundled on customer energy bills to avoid confusion.

The Hawaiian Electric Companies ("HECO")[3] leverage an embedded cost of service study to quantify the utility's costs to provide electric service to customers. The study determines the cost of service based on historical data and then "unbundles" or apportions the costs through multiple cost allocation approaches. These approaches, defined here as "functionalization," "classification," and "allocation," vary depending on "traditional" versus "modern" frameworks.[4]

Functionalization is the process of assigning utility costs of service to the associated power system functions, such as generation-related, transmission-related, distribution-related, or administrative and general costs. Often expenditures are functionalized based on the voltage level at which the costs are incurred. Functionalization answers the general question, “to which operating function do utility costs belong?” Functionalization may also align costs with Federal Energy Regulatory Commission (“FERC) accounts. Traditional approaches would align costs with FERC accounts 364-367 addressing poles, towers, and fixtures; overhead conductors and devices; underground conduits; and underground conductors and devices. Modern approaches align costs with FERC accounts 370 addressing advanced metering infrastructure.

The term "classification" is used to describe the process in cost of service study methods in which costs are assigned into categories such as energy-related, demand-related, or customer-related. Classification answers the general question, “What caused the costs?” Classification occurs after costs are functionalized. This step of the cost of service study further assigns the functionalized costs into categories based on primary cost drivers for those cost. Traditional approaches would assign costs as demand-, energy-, or customer-related. Modern approaches would assign costs to peak hours, off-peak hours, intermediate hours, and site infrastructure.

"Allocation" describes the process of assigning classified costs to the different customer classes based on cost causation principles. The general question that cost allocation answers is “How much should each customer rate class pay?” This is often the final step of a cost of service study which allocates functionalized and classified costs to the various customer rate classes. In Hawaii, major customer classes include residential, commercial, industrial, and street lighting.

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[3] "The Hawaiian Electric Companies" or "HECO" collectively refers to Hawaiian Electric Company, Hawaii Electric Light Company, and Maui Electric Company.

[4] Definitions in this section are from the following sources: Lazar, Jim, Chernick, Paul, and Marcus, William, 2020, *Electric Cost Allocation for a New Era: A Manual*, Regulatory Assistance Project, available at: https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf; “The Basics: Practical Skills for a Changing Utility Environment”, October 13-14, 2015, hosted by NMSU Albuquerque, NM; “NARUC Utility Rate School” May 13-18, 2018, Hosted by Committee on Water of the NARUC; “Introduction to Cost of Service Concepts and Techniques for Electric Utilities”, November 8, 2018, Hosted by EUCI.

Allocation factors can be determined via a number of methods. Generally, allocation methods should reflect cost causation (i.e., methods should be based on the actual activity that drives a particular cost) and recognize customer class characteristics (e.g., electric load demands, peak period consumption, number of customers) that affect cost causation. Utilities and regulators may also leverage policy goals to guide the development of allocation factors. For instance, regulators could determine that alleviating energy burden for low-income customers is a priority policy goal and, therefore, provide an appropriate justification to allocate fewer costs to that customer sub-class for recovery.

With unbundled costs of service, the utility can design rates to charge customers for the electricity they use. The term "rate design" describes the process to determine the pricing structure used to recover revenue requirements. The term explicitly includes itemized prices set forth in tariffs and implicitly includes the underlying theory and process used to derive those prices.[5]

Working group participants emphasized the importance of distinguishing the difference between cost allocation and rate design. Cost allocation, which refers to the apportionment of costs to specific grid functions and customer classes, can be thought of as an *equity* exercise in how to recover costs from each customer class. Whereas rate design, which refers to the price structure for electric service, can be thought of as an *efficiency* exercise for communicating the trajectory of future costs to guide future investment and behavioral response. Importantly, changes to rate design do not have to wait for changes to cost allocation to occur first. The Commission could consider options to update rate design first and then address broader changes to inter-class cost allocation.

Data to inform Time-based rates

Parties' Data Requests

At the start of the working group series, Commission staff requested that Parties provide a list of data necessary to inform their respective initial ARD proposals due in December. Data requested and provided by the Company over the course of the working group series includes:

1. Billing determinants by rate schedule and the workpapers used to generate the demand allocation factors and revenue requirement;
2. Generation reports for fossil and renewable resources, including hourly gross production data;
3. 8760 net load data;
4. Estimated annual avoided line losses;
5. Marginal costs of energy;

[5] Lazar, Jim and Gonzalez, William, 2015, *Smart Rate Design for a Smart Future*, Regulatory Assistance Project, available at: http://www.raponline.org/document/download/id/7680.

6. Costs to install Direct Current Fast Chargers (“DCFC”) electric vehicle (“EV”) charging infrastructure; and
7. Clarification regarding customer-related expenses, demand-side management costs, data management systems, and the relationship between customer class revenue allocation and the most recent cost of service study.

Appendix 1 includes a more detailed table of data requested and HECO’s responses.

HECO Cost of Service Model

HECO's Cost of Service Study and the underlying model currently serve as the primary data source for rate design in Hawaii. HECO's existing cost of service model is a traditional Demand-Energy-Customer model based on historical costs (i.e., an embedded cost of service model). The model classifies investments in assets, such as power plants, transmission, and distribution lines as “demand” or “customer” related. Fuel and other variable operating costs are classified as “energy” costs. These investment costs are apportioned among the customer classes based on various Commission-approved allocation factors.

HECO's 2020 update to the Cost of Service Study leveraged the most recent 2017 class load study as a starting point for the island of Oahu. HECO maintained the revenue apportionment among classes and controlled for other elements to study how those changes impact rates. Specifically, HECO examined the impacts of:

1. Eliminating the Minimum System approach[6] to allocation of distribution costs;

2. Allocating costs that vary with time (according to HECO’s determination) to existing TOU-RI rating periods;

3. Replacing the Average and Excess Demand allocator[7] for Demand costs with an alternate allocator; and

4. Determining a methodology for attributing some portion of costs to providing back-up service/available capability based on the connection to the utility grid.

While the aforementioned elements were studied in the 2020 updated Cost of Service Study for the island of Oahu, broader changes to cost allocation and rate design were not studied as that would have required significant updates to the model.

[6] The Minimum System approach is a method for classifying distribution system costs between customer-related and demand- or energy-related. It estimates the cost of building a hypothetical system using the minimum size components available as the customer-related costs and the balance of costs as demand-related or energy-related.
[7] The Average and Excess Demand Allocator is typically used for the allocation of generation demand-related costs for large commercial and industrial customers.

HECO's Cost of Service Model does not currently include a time dimension, meaning that cost of service is not differentiated by time of day. The model's existing structure does not include a method to allocate generation, transmission, or distribution costs on a time basis. Further, the model considers historical costs to determine the embedded costs to serve each customer class. The model was not designed to analyze forward-looking (i.e., marginal) costs.

Given that the existing cost of service model is based on historical data that does not include a time dimension, working group participants suggested that a reformed model and/or alternative data sources would be necessary to achieve the Commission's goal to design and provide TOU rates for residential and commercial classes.

Other Data to inform Time-Based Rates

Data requested but unavailable from HECO includes:

1. Costs of each grid service (e.g., energy, capacity, or fast frequency response) and timeframe of grid services (as informed by production simulation models);
2. Costs to integrate additional distribution generation (e.g., circuit upgrade costs), including costs associated with advanced inverter functionality;
3. Avoided costs of transmission, distribution, or generation projects resulting from distributed energy resource upgrades;
4. Hourly line loss data;
5. Hourly backfeed to transmission from each substation;
6. Data related to resource constraints (e.g., expected availability of distributed resources and costs incurred when those resources were unavailable or less than expected);
7. Customer-supplied net generation by hour;
8. Detailed changes to customer load profiles in the TOU-RI pilot; and
9. 2019 Residential Appliance Saturation Survey.

Appendix 2 includes a more detailed table of the requested but unavailable data. In general, Parties' requests for data to inform forward-looking costs and rates (e.g., marginal cost of electricity) remains an outstanding data need. Gridworks recommends that stakeholders continue to convene on data needs and assumptions necessary in the long-term. At a minimum, stakeholders should convene to discuss methods and assumptions to allocate capacity costs (generation, transmission, and distribution costs) to times of day.

Rate Design for Commercial Customers

Table 1 provides an overview of HECO's existing commercial and industrial (C&I) rate options. All base rates vary by island and are set to recover the rate case revenue requirement for each customer class, based on a final rate case decision and order from the Commission. Table 2 summarizes base rates for Oahu. Additional surcharges and adjustments apply to base rates (See Figure 1).

For customers subject to demand charges (Schedules J, DS, and P), demand is billed under the "ratchet concept" which is based on the logic that because HECO sizes its facilities to provide service at all times, customers should continue to pay for the demand that they have indicated they need. Therefore, large C&I customers are billed for demand based on the maximum measured demand in a month or the average of one month's maximum measured demand and the highest maximum measured demand in the prior 11 months.

Table 1: Existing C&I Customer Rate Options Descriptions

Schedule	Customer / Demand
G	General service non-demand at or below 25 kW and 5,000 kWh
J	General service demand, above 25 kW or 5,000 kWh and at or below 300 kW for Oahu; 200 kW for Hawaii, Maui, and Lanai; and 100 kW for Molokai
DS	Large power directly served service, commercial customers served from a substation, Oahu only
P	Large power service, above 300 kW for Oahu; 200 kW for Hawaii, Maui, and Lanai; and 100 kW for Molokai
F	Street lighting
TOU-G, TOU-J, TOU-P	Optional commercial time-of-use rates that provide a discount to non-fuel energy during the 9am to 5pm period and higher non-fuel energy charges at other times. Differentials differ by island and schedule. Demand charges and surcharges/adjustments are the same as those under Schedules G, J, and P.

Table 2: Commercial Base Rates (Oahu)

Schedule	G	J	DS	P	F
Customer Charge					
1 Phase	$35.00	$66.00	$425.00	$375.00	$23.50
3 Phase	$63.00	$98.20	-	-	-
Minimum Charge					
1 Phase	$50.00	Customer + Demand Charges	Customer + Demand Charges	Customer + Demand Charges	$35.00
3 Phase	$78.00	-	-	-	-
Demand Charge	None	$13/billed kW, ratchet, 25 kW minimum	$23/billed kW, ratchet, 300 kW minimum	$26.50/billed kW, ratchet, 300 kW minimum	None
Non-Fuel Energy Charge	$0.0960	$0.0514	$0.0189	$0.0292	$0.1031

Proposed Rate Design Options

"Proposal A"[8] leveraged Schedule J as a starting point and recommended replacing the classification step (i.e., allocating costs as demand-, energy-, or customer-related) with functionalized costs allocated by time of day with a 3:2:1 peak to off-peak ratio (Table 3). Under this proposal functionalized costs include:

- Power supply costs - comprised of production capacity and energy costs;
- Grid utilization costs - comprised of the costs of substation and primary lines sized to combined customer loads;
- Grid access costs - comprised of the costs of secondary lines, line transformers, and services sized to maximum loads for individual customers; and
- Customer costs - comprised of customer accounts and customer service costs.

Guiding principles for this proposal include:

[8] All proposals were developed and presented by working group participants. For the purposes of this report, Gridworks assigned titles to participants' proposals shared in working group meetings.

1. Customers should be able to connect to the grid for no more than the cost of connecting to the grid, and

2. Customers should pay for power supply and grid services in proportion to how much they use and when they use it.

Table 3: Proposal A for Commercial Rate Option Based on Schedule J*

	Proposal A
Customer and Billing Charge ($/bill)	$119.55
Grid Access (or Demand) Charge ($/kW)	$1.94
Non-Fuel Energy Charges ($/kWh)	
Priority Peak	$0.376
Mid-peak	$0.251
Off-peak	$0.125

*Inclusive of costs that would be recovered via the Energy Charge Recovery Clause (“ECRC”) and the Purchased Power Adjustment Clause (“PPAC”)

Table 4 summarizes the second proposal, which included a cost-based approach ("Proposal B") and an option that varied non-fuel energy costs by time-of-use ("Proposal C"). The proposed approaches design rates to recover all demand-related costs in a demand charge, all customer-related costs in a customer charge, and all of the remaining revenue requirement in a non-fuel energy charge. No changes to the ECRC or PPAC are proposed. Proposal C included an option to vary the production energy cost by time period; no changes to the demand or customer charge would be made. Table 5 compares the two proposed TOU rate options.

Policy outcomes guiding the proposal included:

1. Revenue neutrality in terms of both the class-specific and overall revenue requirements;

2. Alignment of costs with charges (e.g., all variable costs recovered in a variable charge; all customer-related costs recovered in a customer charge);

3. Rate design can be compared to a cost-of-service rate design; and

4. Customer bill impacts must be considered and should be limited or phased in over time.

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Table 4: Proposed Cost-Based Rate Designs for Commercial and Industrial Customers on Oahu

	G	J	DS	P	F
Customer Charge ($/bill)	$59.04	$212.52	$409.85	$316.90	$35.65
Demand Charge ($/billed kW)	$16.86	$24.89	$27.44	$34.57	$34.26
ECRC ($/kWh)	$0.1023	$0.1023	$0.1023	$0.1023	$0.1023
PPAC ($/kWh)	$0.0328	$0.0284	$0.0265	$0.0272	$0.0345
Proposal B: Non-Fuel Energy Charge (Flat Rate; $/kWh)	$0.0070	$0.0072	$0.0101	$0.0124	$0.0075
Proposal C: Non-Fuel Energy Charge (TOU; $/kWh)					
Priority Peak	$0.1163	$0.1170	$0.1153	$0.1160	$0.1154
Mid-Peak	$0.1103	$0.1110	$0.1095	$0.1101	$0.1095
Off-Peak	$0.1078	$0.1084	$0.1069	$0.1075	$0.1069

Table 5: Comparison of TOU Rate Options for Schedule J Customers

	Proposal A	Proposal C*
Customer and Billing Charge ($/bill)	$119.55	$212.52
Grid Access (or Demand) Charge ($/kW)	$1.94	$24.89
Non-fuel Energy Charges ($/kWh)		
Priority Peak	$0.376	$0.1170
Mid-peak	$0.251	$0.1110
Off-peak	$0.125	$0.1084

*Proposal C does not include the ECRC or PPAC in the prices calculated. The ECRC and PPAC collectively add approximately $0.13 per kWh on Oahu.

Rate Design for Residential Customers and Considerations for Low- and Medium-Income Customers

Table 6 provides an overview of Schedule R, the current residential rate, with usage tiers shown in Table 7. The Schedule R rate design is an increasing tiered rate to encourage energy conservation. Similar to C&I rates, base rates vary by island and are set to recover the rate case revenue requirement for the residential customer class, based on a final rate case decision and order from the Commission. Additional surcharges apply (see Figure 1).

Table 6: Schedule R - Residential Rates in Hawaii by Island

	Oahu	Maui	Hawaii	Lanai	Molokai
Customer Charge ($/bill)					
1 Phase			$11.50		
3 Phase	$20.50		$16.00		
Minimum Charge ($/bill)					
1 Phase			$25.00		
3 Phase			$29.50		
Non-Fuel Energy Charges ($/kWh)					
Tier 1	$0.1068	$0.1212	$0.1303	$0.1231	$0.1405
Tier 2	$0.1183	$0.1438	$0.1638	$0.1438	$0.1670
Tier 3	$0.1371	$0.1502	$0.1748	$0.1502	$0.1785

Table 7: Schedule R Energy Usage Tiers

	Oahu and Maui	Hawaii	Lanai and Molokai
Tier 1	Up to 350 kWh	Up to 300 kWh	Up to 250 kWh
Tier 2	351 - 1200 kWh	301 - 1000 kWh	251 - 750 kWh
Tier 3	Above 1200 kWh	Above 1000 kWh	Above 750 kWh

Each island's Schedule R tariff includes adjustments to non-fuel energy rates for Low Income Home Energy Assistance Program ("LIHEAP") customers and participants in the Special Medical Needs Pilot program. The LIHEAP Adjustment is paid via Schedule R base rates and the Special Medical Needs Pilot is currently funded by shareholders.

Limited time-of-use rate options exist for residential customers - TOU-R, TOU-EV, and TOU-RI. Table 8 summarizes customer enrollment in each TOU rate option. TOU-R and TOU-EV are closed to new customers and TOU-RI is an interim rate option. Peak time periods vary by rate option and/or by island (Table 9).

Table 8: Residential Customer Enrollment in Time-of-Use Rates by Island

	Oahu	Hawaii	Maui	Lanai	Molokai	Total
TOU-R (closed to new customers)	21	7	1	0	0	29
TOU-EV (closed to new customers)	297	9	29	1	0	336
TOU-RI	1,698	579	223	3	13	2,516
Total	2,016	595	253	4	13	2,881

Table 9. Residential Time-of-Use Periods by Rate Option and by Island

	Priority Peak	Mid-peak	Off-peak
TOU-R (Oahu, Maui, Lanai, Molokai)	5-9pm weekdays	7am-5pm weekdays; 5-9pm weekends	9pm - 7am daily; 7am to 5pm weekends*
TOU-R (Hawaii)	3-8pm daily	Not applicable	8pm - 3pm daily
TOU-EV (All Islands)	5-9pm weekdays	7am-5pm weekdays; 7am-9pm weekends	9pm - 7am daily
TOU-RI (All Islands)	5pm - 10pm	9am - 5pm	10pm - 9am

* Does not apply to Maui, Lanai, or Molokai

The primary difference in the rate design between the residential TOU options and Schedule R is the non-fuel energy charge. All surcharges applied to Schedule R also apply to the TOU options. Customer and minimum charges also still apply under all rate options. Under TOU-R and TOU-EV, customer and minimum charges are slightly higher than charges under Schedule R. Customers on the TOU-RI rate have the same customer and minimum charges as customers on Schedule R. Table 10 summarizes the non-fuel energy charges under TOU-RI on each island.

Table 10: TOU-RI Non-Fuel Energy Charge by Island

	Oahu	Hawaii	Maui	Lanai	Molokai
Priority Peak	$0.2468	$0.2763	$0.2307	$0.2367	$0.2250
Mid-Peak	-$0.0448	$0.0043	-$0.0130	-$0.0096	$0.0145
Off-Peak	$0.1585	$0.1808	$0.2159	$0.2140	$0.2254

Considerations for LMI customers

Representatives from Hawaii Energy[9] presented *Working with Hawai'i's ALICE Families: A Hawai'i Energy Perspective* to share considerations for low- and medium-income ("LMI") customers in rate design. Low-income customers face a greater energy burden by paying a higher percentage of their total income towards utility bills, particularly low-income households in multifamily buildings. The impacts of the global pandemic have made energy burdens more significant. Additionally, low-income customers have priorities beyond their energy bill and often do not engage with their utility.

[9] Hawaii Energy is an energy efficiency, conservation, and demand-side management program funded by Hawaiian Electric customers, administered under contract to the Hawaii Public Utilities Commission.

Therefore, a priority outcome for advanced rate design is to lower energy bills for LMI customers, possibly through a low-income rate. Automatically signing up customers into a low-income rate option, rather than requiring customer enrollment, supports customer uptake and retention on the rate schedule.

To have impact for LMI customers, however, rate design should be part of a broader engagement effort to support energy literacy and energy savings among LMI customers.

Trust is necessary to engage customers in energy. In Hawaii Energy's experience, partnerships are key to building trust with community members. Collaborating with partners already working with communities such as Catholic Charities, City and County of Honolulu, and Department of Hawaiian Homelands enabled Hawaii Energy to build community relationships and provide energy savings programs to their targeted audience.

With regard to rate design, Hawaii Energy suggests:

1. Providing education on rate options by talking to people in the community and helping them understand their rate options;

2. Making it easy for customers to enroll in rates and save on their energy bills;

3. Building trust with customers to facilitate outreach and education by meeting customers where they are. Continued partnership with Hawaii Energy and additional partners offering social services can make it simple for customers and streamline energy and cost savings;

4. Deepening investment in outreach and education in communities. Building trust and fostering new relationships requires time and resources and it costs more to engage with LMI customers. This cost should be recognized and accepted as necessary to enable equity in energy services; and

5. Keeping linkages by maintaining community relationships and continuing outreach and education opportunities to ensure success. Partnerships can make things simple.

Proposed Rate Design Options for Residential Customers

Proposed rate design options for residential customers were similar in structure as rate designs proposed for C&I customers. "Proposal D" replaced the classification step with functionalized costs allocated by time of day with a 3:2:1 peak to off-peak ratio. Under this proposal functionalized costs are categorized in the same manner as described for Proposal A.

"Proposal E" introduced Critical Peak Pricing into a residential rate (Table 11). The pricing option would include a "critical peak rate" where electricity would be priced at 10x the off-peak rate. Under this proposal the utility would be able to call a maximum of 10 five-hour "critical peak events" per year where the critical peak rate would apply. For Hawaii's generation mix, future critical peak events could be the result of an extended storm period that significantly reduces solar production. The working group did not discuss definitions of critical peak events in detail.

Table 11: Proposals D and E for Residential TOU Rate Options*

	Proposal D Price	Proposal E Price
Customer and Billing Charge ($/bill)	$10.18	$10.18
Grid Access (or Demand) Charge ($/kW)	$3.13	$3.13
Non-Fuel Energy Charges ($/kWh)		
Critical Peak	-	$1.173
Priority Peak	$0.380	$0.352
Mid-peak	$0.253	$0.235
Off-peak	$0.127	$0.117

*Inclusive of costs that would be recovered via the ECRC and the PPAC.

"Proposal F" established a lower grid access charge for multifamily buildings given the cost efficiencies of serving multiple dwellings relative to single-family homes. Under this proposal, costs per kW of demand would be converted to costs per customer for a multifamily residential sub-class. This would effectively reduce the grid access/demand charge for customers in a multifamily dwelling. Energy costs would be the same as under Proposal D.

"Proposal G" offered an alternative to a TOU rate design for multifamily buildings that would charge customers a flat rate for electricity ($0.221/kWh) and provide a $10/month credit for curtailable water heating service. This proposal was recommended for immediate application, in lieu of waiting to design a TOU rate for customers living in multifamily buildings.

The second set of proposed rate options included a cost-based approach with options to vary energy costs by time-of-use. The time-of-use options included one with ("Proposal H") and one without ("Proposal I") a demand charge (Table 12).

Proposals H and I were designed to recover all demand-related costs in a demand charge, all customer-related costs in a customer charge, and all of the remaining revenue requirement in a non-fuel energy charge. This approach includes an option to vary the production energy cost by time period; no changes to the demand or customer charge would be made.

Policy outcomes guiding the proposal include:

- Revenue neutrality in terms of both the class-specific and overall revenue requirements;

- Alignment of costs with charges (e.g., all variable costs recovered in a variable charge; all customer-related costs recovered in a customer charge);
- Rate design can be compared to a cost-of-service rate design; and
- Customer bill impacts must be considered and should be limited or phased in over time.

All TOU proposals include a 3:2:1x peak to off-peak ratio. Table 12 compares the proposed TOU options.

Table 12: Summary of Residential TOU Proposals*

	Proposal D	Proposal E	Proposal H	Proposal I
Customer and Billing Charge ($/bill)	$10.18	$10.18	$11.50	$11.50
Grid Access (or Demand) Charge ($/kW)	$3.13	$3.13	$0.00	$4.00
Non-Fuel Energy Charges ($/kWh)				
Critical Peak	-	$1.173	-	-
Priority Peak	$0.380	$0.352	$0.1730	$0.1277
Mid-peak	$0.253	$0.235	$0.0577	$0.0426
Off-peak	$0.127	$0.117	$0.1153	$0.0851

* Proposals H and I do not include the ECRC or PPAC. The ECRC and PPAC collectively add approximately $0.13 per kWh on Oahu.

Rate Design for Electric Vehicle Charging

HECO currently offers two rate options for residential customers with EV charging - TOU-EV and TOU-RI. These options are discussed in the Rate Design for Residential Customers section, above. Additionally, five commercial rate options are available for EV charging: EV-F, EV-U, EV-BUS-J and E-BUS-P, and EV-MAUI (Tables 13 and 14). All rate options, with the exception of EV-MAUI, are pilot rate options scheduled to expire in 2023.

Table 13: Summary of EV-F, EV-U, and EV-MAUI Rate Options

	Oahu		Hawaii		Maui			Lanai		Molokai	
	EV-F	**EV-U**	**EV-F**	**EV-U**	**EV-F**	**EV-U**	**EV-MAUI**	**EV-F**	**EV-U**	**EV-F**	**EV-U**
Fixed Charge ($/bill)	$5.00	-	$5.00	-	$5.00	-	-	$5.00	-	$5.00	-
Non-Fuel Energy Charges ($/kWh)											
Priority Peak	$0.239	$0.57	$0.290	$0.63	$0.292	$0.62	$0.403	$0.336	$0.72	$0.3205	$0.66
Mid-Peak	$0.159	$0.49	$0.170	$0.51	$0.172	$0.49	$0.283	$0.216	$0.60	$0.2005	$0.54
Off-Peak	$0.209	$0.54	$0.270	$0.61	$0.272	$0.60	$0.383	$0.316	$0.70	$0.3005	$0.64

Table 14: Summary of EV-BUS-J and EV-BUS-P Schedules

	Oahu		Hawaii		Maui	
	EV-BUS-J	**EV-BUS-P**	**EV-BUS-J**	**EV-BUS-P**	**EV-BUS-J**	**EV-BUS-P**
TOU Metering	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Applicable On-Peak Demand Charge ($/kW)	$13.00	$26.50	$13.00	$25.00	$13.00	$25.00
Non-Fuel Energy Charges ($/kWh)						
Priority Peak	$0.1704	$0.1234	$0.2521	$0.1753	$0.2721	$0.2321
Mid-Peak	$0.0143	-$0.0037	$0.0467	$0.0212	$0.0327	$0.0148
Off-Peak	$0.0299	$0.0095	$0.0666	$0.0377	$0.0583	$0.0381

Unique Considerations for EV Charging

Rocky Mountain Institute (RMI) presented *Best Practices for EV Rate Design* to share lessons learned from Level 2 and Direct Current Fast Charging ("DCFC") EV charging infrastructure. RMI shared that Level 2 charging, rather than DCFC, is better suited for TOU rate design to encourage managed charging. The timing of DCFC charging is less predictable and the load is more "spiky," which minimizes the potential to influence customer behavior through rate design. Additionally, due to the cost of DCFC infrastructure, it is not yet cost competitive with gasoline; whereas Level 2 charging costs are cost competitive with gasoline in Hawaii. RMI offered the following rate design principles for EV chargers:

- Tariffs should be time-varying, and preferably dynamic, while recovering most utility costs;
- Tariffs should have low fixed charges which primarily reflect routine costs for things like maintenance and billing;
- Tariffs should reflect the actual cost of providing service, and should charge more for coincident peak demand;
- If demand charges are necessary, they should be scaled with utilization rates, and recover only location-specific costs of connection to the grid, not upstream costs, so that customers sharing capacity share costs, and continuous-capacity customers are not subsidized by short, infrequent loads.

Rate Design Options EV charging

One presentation noted that well-designed TOU rates would also serve EV charging, provided that demand charges are low. The proposal presented the Critical Peak Pricing Rate Design option previously shared (see Table 11) as a cost-effective option for residential customers.

The presentation also noted that high demand charges in commercial rates present a barrier to cost-effective EV charging, emphasizing the importance of low demand charges and managing charging to avoid priority peak periods. The presentation suggested limiting demand charges to site infrastructure costs.

Further, two additional TOU EV rate options were proposed using a 1x - 1.5 cent - 3x pricing structure (Table 15).

Table 15: Proposed TOU EV Rates*

	Proposal J	Proposal K
Customer Charge ($/bill)	$11.50	$11.50
Demand Charge ($/kW)	$0	$4
Non-Fuel Energy Charges ($/kWh)		
Priority Peak	$0.173	$0.1279
Mid-peak	$0.0577	$0.0426
Off-peak	$0.1154	$0.0852

* Proposals do not include ECRC or PPAC. The ECRC and PPAC collectively add approximately $0.13 per kWh on Oahu.

Recovery Charges and Surcharges

All revenue recovery for HECO is reconciled to true up any differences between the revenue requirement and the revenue collected via rates. Figure 1 summarizes the recovery charges and surcharges currently within rates.

In the HELCO and HECO rate cases, the Company requested to change the Revenue Balancing Account ("RBA") Rate Adjustment[10] implementation method from a flat energy charge applied to all rate schedules to a percentage of base bill.[11] This issue was directed to the DER docket because surcharges and recovery charges may be affected by the application of TOU rates.

Beyond the specific request for the RBA Rate Adjustment, the Commission indicated it is broadly open to party perspectives on surcharges and the related recovery mechanisms, with the exception of the Green Infrastructure Fee.[12] Refer to Appendix 3 for the Commission's questions regarding this issue.

Figure 1: Surcharges Applied to HECO Electric Rates

Existing Revenue Recovery Charges

Cost Component	Means of Collection	Basis for Collection	Means of Reconciliation	Basis for Reconciliation	Frequency of Reconciliation
Fuel and Purchased Energy	ECRC	Energy Charge All Schedules	ECRC	Energy Charge All Schedules	Monthly Adjust Quarterly Recon
Purchased Power	PPAC	Energy Charge By Schedule	PPAC	Energy Charge By Schedule	Quarterly
Non-Fuel-PP O&M & Capital Recovery	Schedules RGJPF	Customer Charge Non-Fuel Energy Demand Charge Pow Fact. / Riders	RBA Rate Adjustment	Energy Charge All Schedules	Annual
DSM/DRAC/IRP REIP	DSM/IRP Surcharge REIP Surcharge	Energy Charge By Schedule	DSM/IRP REIP	Energy Charge By Schedule	Quarterly or Annual
Green Infrastructure Fee	Green Infra. Fee Surcharge	Customer Charge	Green Infra. Fee Surcharge	Customer Charge	Periodic Semi-Annual
Public Benefits Fee	Public Benefits Fee Surcharge	Energy Charge All Schedules	Public Benefits Fee Surcharge	Energy Charge All Schedules	Annual
RAM/ARA MPIR/PIMs	RBA Rate Adjustment	Energy Charge All Schedules	RBA Rate Adjustment	Energy Charge All Schedules	Annual

Source: Haiku Design and Analysis

[10] The RBA Rate Adjustments serves as the decoupling mechanism, which allows HECO to recover or reimburse any difference between the revenue requirement and the revenue recovered via rates.

[11] The base bill is the non-fuel and purchased power component of the various customer charges.

[12] The Green Infrastructure fee structure is established in statute and is not subject to change in a Commission process.

Advanced Rate Roll Out

Lessons Learned from Other Jurisdictions

Lawrence Berkeley National Laboratory ("LBNL") presented *Residential Time-Based Rates: U.S. Experience* to share observations of customers' experience with time-based rates, particularly vulnerable customers such as LMI customers, seniors, and people with special medical needs. The presentation emphasized the importance of employing marketing materials that resonate with customers and recommended that, in general, electric utilities should invest more than they are currently spending into marketing time-based rates to residential customers. LBNL recommended conducting market research and testing market messages to ensure that the TOU marketing strategy supports customer enrollment and retention on the rate schedule.[13]

With regard to vulnerable customers, LBNL shared recent research from California and Vermont on the experience of vulnerable customers with time-based rates. LBNL noted that vulnerable customers are somewhat less likely to enroll in time-based rates but, once enrolled, they are no more or less likely to drop out of the rate than their non-vulnerable counterparts. Additionally, the research from California found that LMI customers and seniors may be more responsive to TOU price signals (i.e., they reduce demand during the peak period) than the general population.[14] [15]

With regard to pilots for new rate designs, LBNL recommended first identifying the specific questions that a pilot would answer and researching whether other jurisdictions have already addressed those questions through pilots. Stakeholders would need to make a determination as to whether the results in other jurisdictions are applicable to the specific questions that Hawaii wants to answer. A pilot would be warranted if the particular answers needed to make decisions down the road haven't already been answered. If questions have been answered, Hawaii should move ahead to implement a program.

Marketing, Education, and Outreach

The Sacramento Municipal Utility District ("SMUD") presented *SMUD's Time-of-Day Rate Implementation* to share their experience with transitioning their residential customers to TOU rates. The presentation focused on the marketing, education, and outreach efforts SMUD employed to

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[13] Refer to Cappers, P. & Spurlock, (2020) A., *A Handbook for Designing, Implementing, and Evaluating Successful Electric Utility Pilots*, Lawrence Berkeley National Lab, for more detail (https://emp.lbl.gov/publications/handbook-designing-implementing-and).

[14] George, S., Bell, E., Savage, A., Dunn, A. and Messer, B. (2017a) California Statewide Opt-in Time-of-Use Pricing Pilot - Interim Evaluation. Prepared for The TOU Working Group under contract to Southern California Edison. April.

[15] George, S., Bell, E., Savage, A., Dunn, A. and Messer, B. (2017b) California Statewide Opt-in Time-of-Use Pricing Pilot - Second Interim Evaluation. Prepared for The TOU Working Group under contract to Southern California Edison. November.

prepare their staff and customers for the rate change. SMUD shared that planning and preparation for this transition began several years before it was implemented. During this time, internal tools such as a Meter Data Management System, Meter Data Unification System, Bill Scenario Tool, and a Rate Change Automation Tool were developed to support back-office changes. These internal tools complemented customer-facing tools that provided customers with data on their energy usage, energy bill, and rate options.

SMUD's marketing and education campaigns to promote TOU rates reached households 6+ times via customer-specific rate comparison reports, door hangers, automated calls, and postcards. Additionally, SMUD attended 145 community events to offer presentations and workshops on TOU rates. As a result, during the course of TOU rate roll out, customer awareness of TOU rates rose from 55% to 90%.

SMUD's lessons learned include:

- High levels of collaboration are necessary across the organization and within departments and teams. Across the SMUD organization, everyone was aware of the rate transition and working together to support TOU rate roll out. Strong executive leadership was also important to champion the change.

- Customer-facing tools were instrumental for customer engagement and empowerment. Online tools helped customers understand how a rate change could impact them and the options and control that customers had to mitigate any potential impacts.

- Internal tools facilitated operational efficiencies. SMUD's internal tools enabled automated billing changes and customer processing, which streamlined implementation efforts and saved the organization time and resources

- Consulting with staff with strong billing knowledge ensured that bill impacts were accurately calculated and communicated to customers. SMUD found that employees with a strong billing background served as valuable experts who were the best at validating rate designs and potential bill impacts of the new rates. This information was critical for customer engagement.

- Offer customers choices. While SMUD's goal was to enroll all residential customers in TOU rates, customers appreciated having options and autonomy to make their own decisions about their energy bills.

Commission Guidance

In the last working group meeting, Commission staff provided guidance to parties for preparing their initial proposals for advanced rate design. Generally, proposals should discuss the policy considerations and tradeoffs among priorities addressed by the proposals. Additionally, proposals should be well-supported with data to justify party positions and to allow the Commission to evaluate ARD options.

Strong proposals will include party perspectives on:

- Benefits and drawbacks of specific rate design options
- Addressing challenges of LMI customers
- Pilots
- Surcharges
- Rate Roll Out and Ongoing Implementation Plans
- Bill impacts
- Marketing, Education, and Outreach
- Allocation of costs based on time of day
- Methods and performance indicators that should be used to evaluate rates

Slides with the Commission's guidance shared in the last working group meeting are included as Appendix 3 of this report and posted to the Commission's Document Management System for Docket 2019-0323.[16]

In accordance with Order 37066, the Advanced Rate Design Track of this docket will continue through 2021 to accommodate a number of considerations including the potential need for data exchange and evaluation of rate design studies (e.g., load research, cost allocation studies, cost of service analyses, unbundled cost analysis, etc.) and progress made in the DER Program Track.

Working Group Outcomes

Several themes emerged in working group discussions including:

- Now is the time to evolve rate design in Hawaii. Updated rate designs are needed today and the transition to move all customers onto those rates needs careful consideration and robust customer engagement and education.

- Prevent rate shock and mitigate potential impacts to customers. All Parties agreed that changes to rate design should minimize bill impacts to customers; however, Parties had few, if any, tools to estimate the possible bill impacts resulting from their proposals.

- Unique considerations apply for LMI customers. Hawaii's clean energy transition will only be successful if all customers are engaged. Engaging LMI customers requires building trust and investing in community outreach.

- Stakeholders should continue to discuss long-term data needs for rate design and work together to develop a plan for fulfilling those needs over time.

[16] See https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A20K04A94813E00039.

With regard to working group objectives, the working group series successfully facilitated dialogue and shared learning about rate design approaches for Hawaii. Working group discussions supported collaboration on specific rate design options such that parties proposed several options for TOU rates in working group meetings. Further, the working group discussed HECO's Cost of Service Study in detail in working group meetings and in the two supplemental meetings addressing data.

That said, limited progress was made with regard to modifications to demand charges. Additionally, Parties' proposals took different approaches to unbundling and allocating costs and, therefore, there is not yet agreement among stakeholders on the extent to which revenue requirements will be unbundled in ARD proposals.

Near- and long-term data needs to inform party proposals remains an outstanding area for stakeholder coordination and collaboration. Appendix 2 summarizes data requested by Parties but unavailable from HECO. Gridworks recommends that Parties convene in Q1 2021 to discuss data gaps and develop a plan to address those gaps prior to the Parties filing final ARD proposals in March 2021.

GRIDWORKS

Appendix 1: Data Requested by Parties and Provided by HECO

Request	Status
Billing determinants by rate schedule for the most recent year available for Maui and Oʻahu (and if available, Hawaiʻi Island) and the workpapers that use that data to generate the calendar year revenue requirement.	Provided by HECO
Billing determinants used in the cost of service model.	Provided by HECO
All data used to create the demand allocations in the cost of service study and the workpapers by which those allocations were calculated.	Provided by HECO
For each class, provide the TOU billing determinants for the customers currently enrolled in the interim TOU rate monthly and annually for each year for which data is available.	Provided by HECO
Hourly curtailment of renewable generation from each renewable generating unit.	HECO provided the curtailment reports that are in the December 2019 monthly report submitted for the Reliability Standards Working Group Exhibits in Docket 2011-0206.
Generation by fossil generating unit by hour for the year used in the cost of service study.	HECO provided production simulation generation data for HECO TY2020, HELCO TY2019, and Maui TY2018 to be used as reference/proxy.
Generation by renewable generating station owned or contracted by hour for the year used in the cost of service study.	HECO provided production simulation generation data for HECO TY2020, HELCO TY2019, and Maui TY2018 to be used as reference/proxy.
Hourly fossil generation by generating station that was of a “reliability must-run” nature (as opposed to economic dispatch) for the year used in the cost of service study.	See the production simulation generation data by hour for HECO TY2020, HELCO TY2019, and Maui TY2018. The production simulation satisfies the total system requirement, including reserves, and all units contribute to the system requirement.
Estimated avoided line losses.	HECO provided annual line losses included in HECO TY2017, HELCO TY2019, and Maui TY2018 rate cases.

GRIDWORKS

Request	Status
Costs to install EV charging infrastructure.	HECO provided data on the costs of Direct Current Fast Chargers via the 2019 *Annual Report on the Progress and Status of the Commercial Public Electric Vehicle Charging Service Pilot Rates* (Transmittal No. 13-07).
Hourly marginal cost, by location (if there is significant variation across locations) and an indication of the lowest granularity that the marginal cost information may be available (e.g., 5 minutes). Historical temporal marginal cost by season.	Partial response provided. System marginal costs of energy used in support of 2020 TOU-RI rate modifications were provided. Additionally, HECO provided historical system lambda values reported in FERC Form 714 for Oahu for 2018 and 2019.
Hourly gross production and gross consumption data, with all available characterization tags such as by customer class. Historical temporal production and consumption by season.	Partial response provided. HECO provided hourly gross production data on August 14, 2020. HECO does not have customer hourly consumption data.
8760 net load data including the breakout of resource profiles (e.g., DER/BESS, EV, etc.) provided as annual peak forecasts in the Companies' previous response. For each forecast, please provide a detailed methodology, including how any of the data or forecasts methodologies were modified or updated after being used for the IGP process. Also, 8760 near-term load forecast, including a detailed methodology.	These requests were addressed in HECO's response to DER Parties HECO-IR-22 filed on November 13, 2020 in this same Docket No. 2019-0323 (Program Track DER Policies) and in the response to PUC-HECO-IR-1 filed on July 2, 2020 in Docket No. 2018-0165 (IGP).
Sub-account entries for costs designated as "customer accounts expense" and "customer service expense."	Provided by HECO
Detailed explanation for how DSM costs are recorded and recovered	Provided by HECO
Comparison between customer class revenue allocation and the results of the most recent cost of service study for each of the Hawaiian Electric Companies.	Provided by HECO
Current and future Meter Data Management System (MDMS), billing engine, and vendor.	No MDMS is currently used for billing. Future advanced meters and MDMS will be Landis & Gyr. The current and future billing engine is and will remain SAP.

Appendix 2: Data Requested by Parties but Unavailable from HECO

Request	Status
Costs to integrate additional distributed generation (e.g., circuit upgrade costs).	HECO does not have this information. It may be possible to identify this information through Grid Needs in the Integrated Grid Planning (IGP) process for the assumed DER forecasts.
Cost of each grid service (e.g., energy, capacity, regulation, inertia or fast frequency response) and timeframe of grid service (as informed by production simulation models).	HECO does not have these data. It may be possible to identify the value of each of these services in the IGP docket.
Estimated costs associated with transmission, distribution, or generation projects that did not need to be constructed due to DER upgrades.	HECO does not currently track these data.
Data related to resource constraints (e.g., expected availability of distributed resources and costs incurred when those resources are unavailable or less than expected).	HECO does not currently track these data.
Costs associated with advanced inverter functionality, compliance with technical standards and requirements.	Circuit upgrade costs have not been tracked against advanced inverter functionality. Other than internal resources that are used to manage advanced inverter compliance, costs have not been tracked for advanced inverter compliance.
Hourly backfeed to transmission from each substation for the year used in the cost of service study.	Data are not used or presented in the cost of service study.
Any data on line losses or marginal line losses by hour for a recent year (or other period if less than a year is available.)	Hourly line loss data are not available. Annual line losses data were provided.
Customer-supplied net generation delivered to the system by hour for the year used in the cost of service study, separated between DER program type.	These data are not used in the cost of service study and are not available from HECO. A third party has a sample dataset for gross production from Smart Export program participants available.
Changes to customer load profiles in the TOU-RI Pilot	HECO does not currently track these data beyond what is presented in the Annual TOU-RI Reports. HECO provided TOU energy usage data for customers in the Oahu advanced meter pilot.
2019 Residential Appliance Saturation Survey	The Hawaiian Electric Companies have not prepared a report for the residential appliance saturation survey. The data that the Companies provided to AEG for their work is available; some of the data are reflected in the Attachments to the AEG Market Potential Study.

Appendix 3: Commission Guidance for ARD Proposals

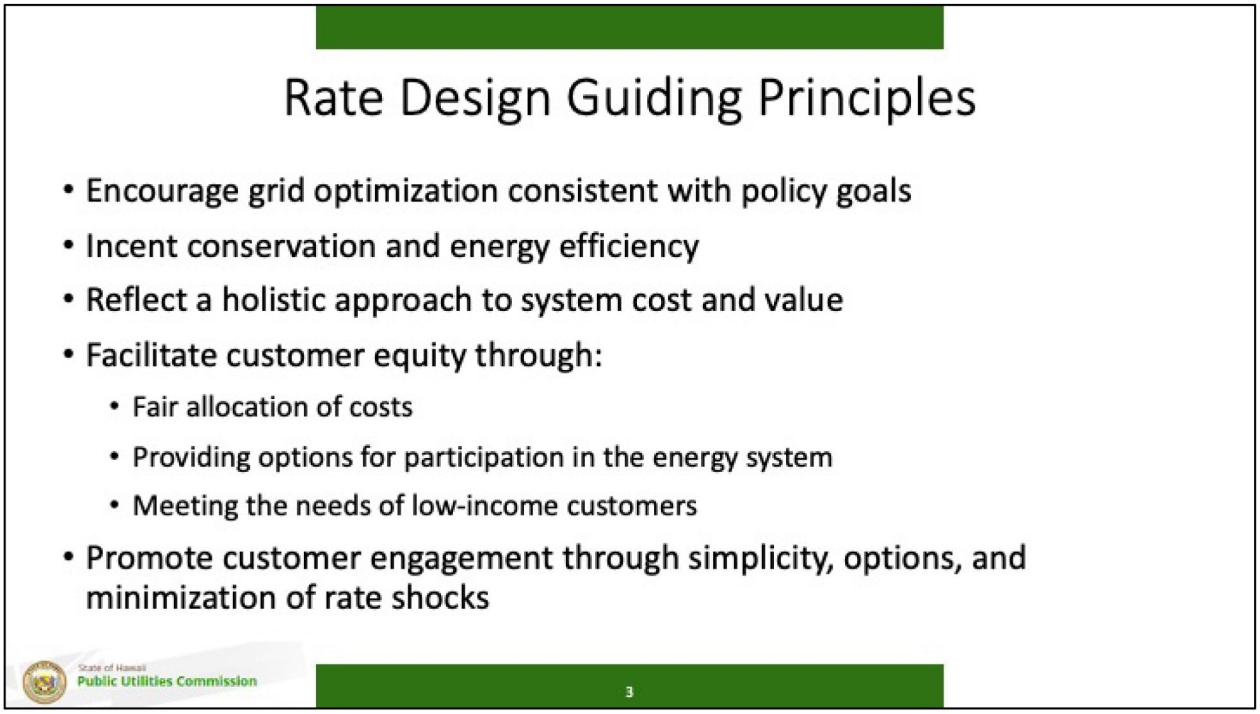
Commission staff shared the following presentation at the October 28 meeting of the ARD working group. This presentation is also posted to the Commission's Document Management System under Docket 2019-0323, and accessible at:
https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A20K04A94813E00039

Presentation notes: None

Presentation notes:

This end-state and a transition to opt-out rates will take time and must be carefully and gradually implemented. Progress will occur in increments. Party proposals should provide a thoughtful and flexible **roadmap** to this end-state.

GRIDWORKS



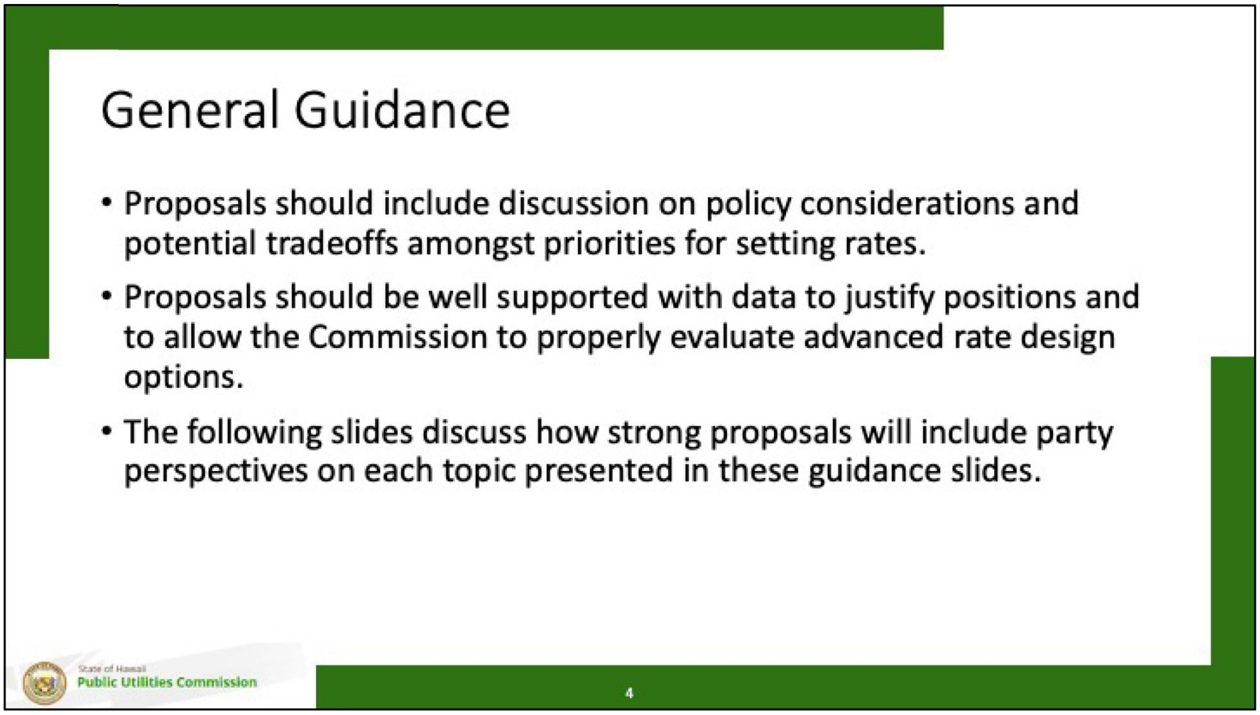
Presentation notes:

Policy goals include:

- Improving grid resilience
- Promoting reliability
- Reducing environmental impacts
- Providing cost savings to customers
- Providing customers the opportunity to better influence and control their bills

Reflect a holistic approach to system cost and value:

- This should include forward-looking costs when possible to align customer behavior with the minimization of utility investments



Presentation notes:

Given the many policy considerations and potential tradeoffs amongst priorities in setting rates, proposals should include adequate information and data to justify positions and to allow the Commission to properly evaluate advanced rate design options.

The following slides discuss how strong proposals will include party perspectives on:

- Benefits and drawbacks of specific rate design options
- Addressing challenges of low- and moderate-income (LMI) customers
- Pilots
- Surcharges
- Rate Roll Out and Ongoing Implementation Plans
- Bill impacts
- Marketing, Education, and Outreach
- Allocation of costs based on time of day
- Methods and performance indicators that should be used to evaluate rates

Low- & Moderate- Income Customer Considerations

- Parties should comment on the merits and feasibility of pursuing a subsidized rate for LMI customers.
- Proposals should frame the issues:
  - What challenges currently faced by LMI customers are being considered?
  - What specific equity outcomes will be achieved?
  - Do proposals use rate and/or programmatic approaches?
  - Which and how many customers are included or eligible?
  - How will eligible customers be identified?
- Proposals should include implementation details.

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Presentation notes:

Proposals should frame the issues:

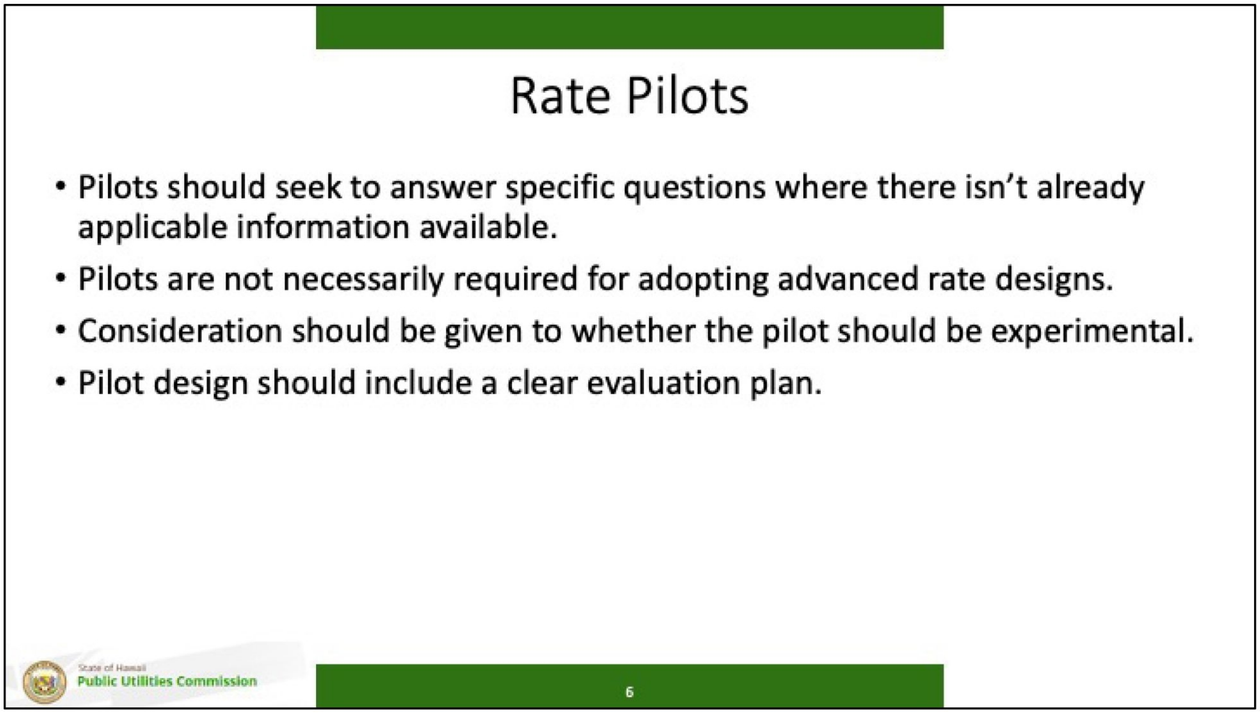
- What challenges currently faced by LMI customers are being considered?
- What specific equity outcomes will be achieved?

How do proposals address identified challenges and create new opportunities to facilitate customer equity?

- Do proposals use rate and/or programmatic approaches?
- Which and how many customers are included or eligible?
- How will eligible customers be identified?

What implementation details will facilitate easy access to proposed options for LMI customers?

- Marketing directly to customers
- Convenient enrollment
- Ongoing education and engagement
- Strategic partnerships



Presentation notes:

Pilots should be reserved for rates/programs that are more advanced than simple TOU rates.

Clear evaluation plans should include establishing metrics for testing hypotheses, identifying data needs and collections methods to support metrics development, and selecting analytical evaluation techniques to test hypothesis.

Surcharges

- Parties should address all surcharges
  - RBA, ECRC, PPAC, MPIR, PBF, IRP
  - Which surcharges are necessary?
  - Do the surcharges align with rate design objectives and goals?
- How should surcharges be allocated to customer classes?
- How should surcharges recover costs through fixed ($/customer), demand ($/kW), or energy charges ($/kWh), or other (e.g. % of bill) methods?

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Presentation notes:

Note: Table with details of surcharge rate design included in appendix of this presentation.

Revenue Balancing Account (RBA)

- Parties should address HECO and HELCO's requested modifications to the RBA and associated policy considerations for all Companies.
  - Do the methods reasonably maintain rate design and customer class allocations?
  - Does the proposal facilitate fairness of adjustment recovery across customer classes?
  - Should surcharges be non-bypassable (apply in addition to minimum bills charges)?
- Are there other design options to consider for the RBA?

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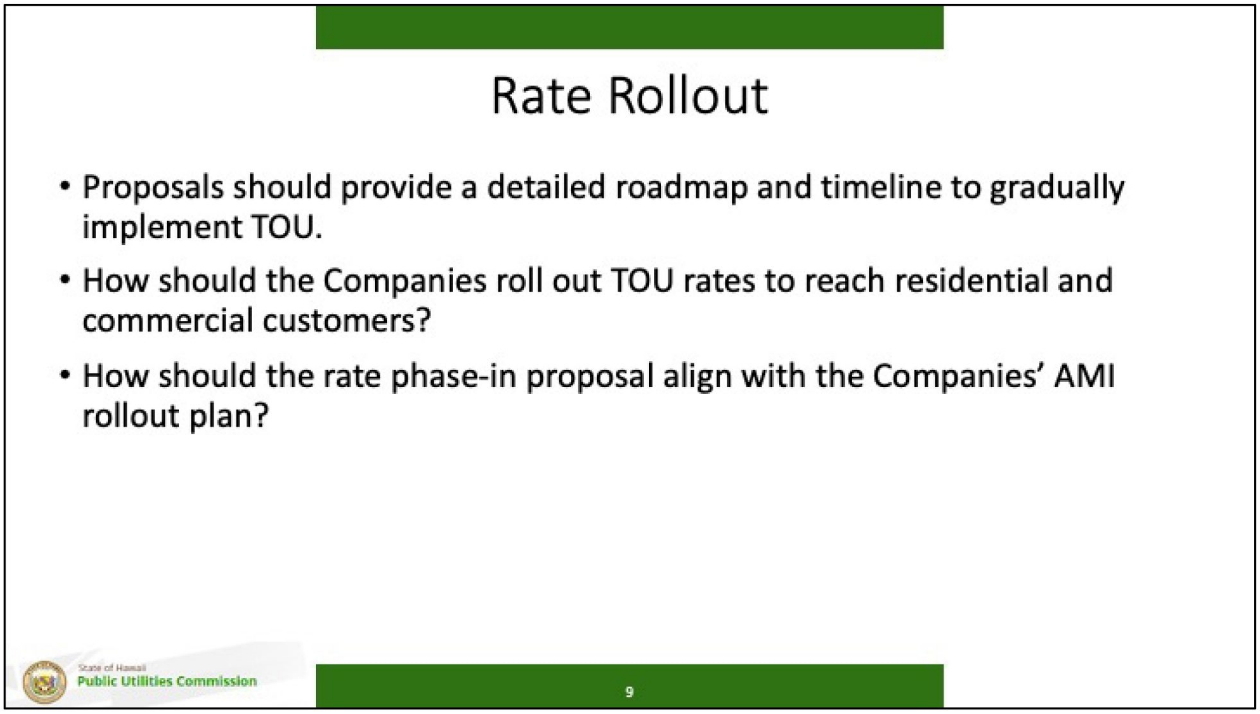
Presentation notes:

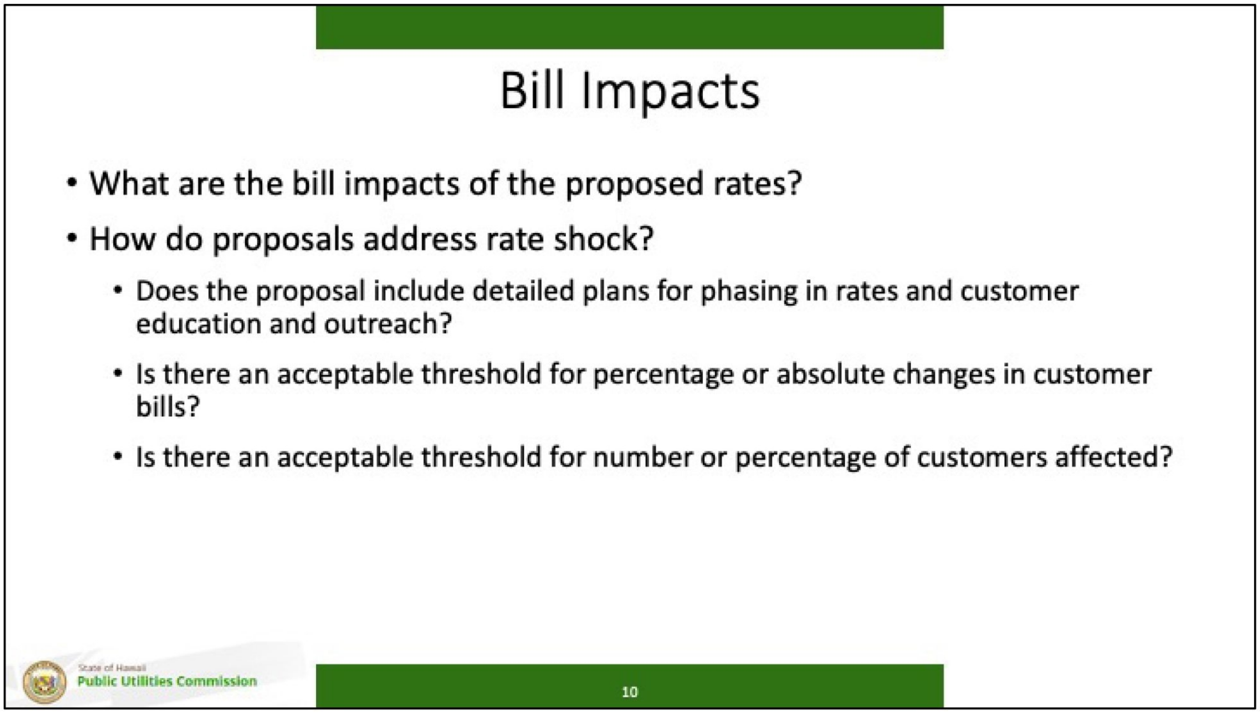
The request from HECO and HELCO is consideration for changing the basis for applying the RBA rate adjustments from an energy charge billed in cents/kWh to a charge billed as a percentage of the non-ECRC portion of the customer bill.



Presentation notes:

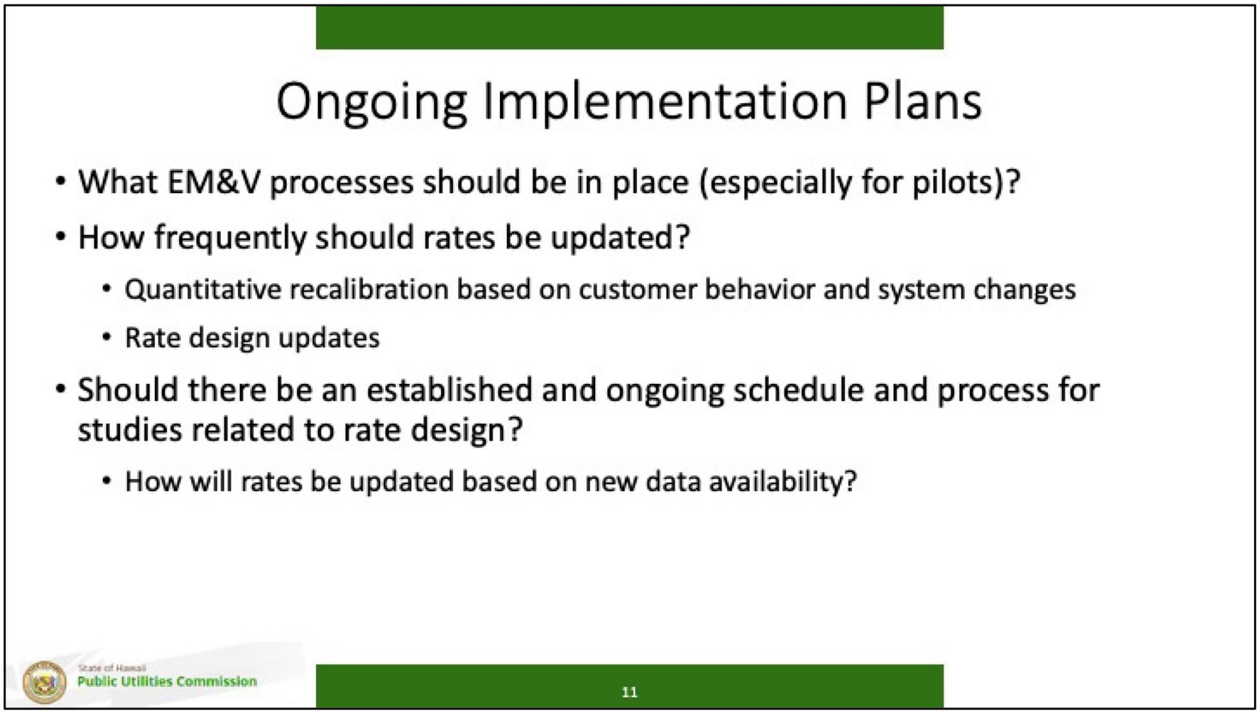
How should the Companies roll out TOU rates to reach residential and commercial customers?

- To existing TOU customers, AMI customers, new customers, etc.
- How long should the total rate rollout take?
- When will rates be offered an opt-out basis?



Presentation notes:

Bill impact analysis should consider what bill impacts are for customers with different levels of consumption and demand (including both percentage and absolute changes)



Presentation notes:

What EM&V processes should be in place (especially for pilots)?

- How frequently should rates and pilots be evaluated?
- How will EM&V incorporate stakeholder input?
- What key performance metrics should be considered?

Cost Classification and Customer Class Allocation

- For initial and final proposals, parties should pursue the approaches to cost classification and allocation of costs to different customer classes in a manner they feel will best meet rate design objectives.
- These may include:
  - Traditional classification (demand-, energy-, and customer-related)
  - Time-based classification, including the DER Parties' proposed "workaround" or proxy approach
  - Adjustments to inter-class allocation of costs using currently available data

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Presentation notes: None

Marketing, Education, and Outreach (ME&O)

- Parties should specify how stakeholder input has informed initial proposals.
- How will new rates be marketed, what enrollment mechanisms will be employed to reach customers, and how will ongoing education be provided?
  - What partnerships can be leveraged?
  - How will web-based options be employed?
- How will the Companies and partners assist customers with large bill impacts?

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Presentation notes: None

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Presentation notes:

How do the rates in your proposal provide a system resource or resources or support grid service program proposals?

- Load shaping
- Load shedding and building
- Others?

Presentation notes: None

Appendix

Presentation notes: None

GRIDWORKS

Cost Component	Means of Collection	Basis for Collection	Means of Reconciliation	Basis for Reconciliation	Frequency of Reconciliation
Fuel and Purchased Energy	ECRC	Energy Charge All Schedules	ECRC	Energy Charge All Schedules	Monthly Adjust Quarterly Recon
Purchased Power	PPAC	Energy Charge By Schedule	PPAC	Energy Charge By Schedule	Quarterly
Non-Fuel-PP O&M & Capital Recovery	Schedules RGJPF	Customer Charge Non-Fuel Energy Demand Charge Pow Fact. / Riders	RBA Rate Adjustment	Energy Charge All Schedules	Annual
DSM/DRAC/IRP REIP	DSM/IRP Surcharge REIP Surcharge	Energy Charge By Schedule	DSM/IRP REIP	Energy Charge By Schedule	Quarterly or Annual
Public Benefits Fee	Public Benefits Fee Surcharge	Energy Charge By Schedule	Public Benefits Fee Surcharge	Energy Charge By Schedule	Annual
RAM/ARA MPIR/PIMs	RBA Rate Adjustment	Energy Charge All Schedules	RBA Rate Adjustment	Energy Charge All Schedules	Annual

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Presentation notes: None

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