UHERO
THE ECONOMIC RESEARCH ORGANIZATION
AT THE UNIVERSITY OF HAWAIʻI

A Proposal for Real-Time Pricing Tariffs for Large Electricity Customers

AUGUST 27, 2024

UHERO

THE ECONOMIC RESEARCH ORGANIZATION
AT THE UNIVERSITY OF HAWAIʻI

A Proposal for Real-Time Pricing Tariffs for Large Electricity Customers

Michael J. Roberts
UHERO Research Fellow and Professor of Economics

Ethan Hartley
Graduate Assistant

Victoria Rhinebolt
Graphic Design and Layout

2424 MAILE WAY, ROOM 540 • HONOLULU, HAWAII 96822
(808) 956-7605 • UHERO@HAWAII.EDU

Executive Summary

In a real-time pricing tariff (RTP), utilities charge electricity customers an incremental price that equals the marginal cost of electricity, averaged over a short time window, typically one hour. This tariff typically combines the marginal price with a fixed charge to help recover fixed and infra-marginal costs. Marginal costs are determined using local wholesale market prices or, in areas without markets, a day-ahead or hour-ahead forecast of marginal costs as measured by the balancing authority's automatic generation control system. Ideally, marginal costs should incorporate incremental environmental costs and marginal transmission and distribution costs, which can vary by local node in a distribution network, particularly when lines are congested. These prices are referred to as locational marginal prices (LMP).

LMPs provide an efficient pricing mechanism for customers purchasing electricity and for smaller independent generators supplying electricity to the grid. LMP reflects the incremental savings to the utility when a customer consumes one less kilowatt-hour or supplies an additional kilowatt-hour to the grid. LMP pricing embodies the cost causation principle in regulation, which holds that costs should be borne by those who cause them. Deviations from LMP lead to inefficiencies and cost transference, where some customers implicitly subsidize others. Regulators can address concerns about revenue collection, equity, and fairness through adjustments to fixed charges, with minimal impact on efficiency.

As Oahu's electric grid transitions to clean energy, characterized by variable wind, solar, and storage resources, the marginal cost of electricity will become increasingly variable across time and location. Consequently, the value of using LMP for customer billing and compensating distributed generation will increase significantly. This document outlines a proposal to implement RTP for large commercial customers (schedules P and DS), with the University of Hawai'i as the initial pilot customer under the tariff.

One of the longest-running and most successful RTP tariffs is offered by Georgia Power to its commercial customers. Georgia Power is a vertically integrated utility similar to Hawaiian Electric Company and operates without a wholesale market. The tariff applies marginal-cost pricing to deviations from a customer baseline load (CBL) to maintain revenue neutrality. This structure implicitly establishes a fixed charge, allocating inframarginal costs in line with historical precedent.

The proposal presented here resembles Georgia Power's tariff but includes additional details on how the utility would calculate marginal costs during the transition to clean energy, how CBLs would be determined, and how RTP could credit electricity provided by distributed customer resources.

This document includes seven sections:

1. **Georgia Power RTP Tariff**: A detailed overview of Georgia Power's real-time pricing (RTP) tariffs, including their structure and outcomes.

2. **Proposed Hawaii Tariff**: The suggested RTP tariff for commercial customers in Oahu, highlighting key features and expected impacts.

3. **Compensation for Backfeeding and Off-Site Generation**: An explanation of how the utility would compensate large customers for generating electricity on-site or off-site and feeding it back into the grid.

4. **Benefits of RTP**: A discussion of the advantages of RTP pricing for non-participating customers and its alignment with the State's renewable energy objectives.

5. **Technical Aspects of RTP**: An in-depth explanation of the factors influencing

marginal costs, including time variations, the impact of renewable energy and storage, and responses to common technical questions.

6. **Challenges of RTP**: An examination of potential challenges in implementing RTP, such as setting appropriate fixed charges based on customer baseline load (CBL), accurately forecasting future demand and supply, and proposed solutions to these issues.

7. **University of Hawaii as a Pilot RTP Customer:** A simulation study of the RTP tariff applied to the University of Hawaii, demonstrating potential benefits for the university, Hawaiian Electric Company, and other stakeholders.

1. Georgia Power RTP Tariff

Georgia Power offers two RTP tariffs, one based on day-ahead forecasts of marginal cost and one based on hour-ahead forecasts of marginal cost. These tariffs are tailored for commercial customers with peak demands of at least 250 kW for day-ahead forecasts and at least 5000 kW for hour-ahead forecasts. The tariffs are popular and successful, with "43% of eligible customers and 82% of eligible load … enrolled in one of the two RTP tariffs by 2004."

The specific language outlining how the tariff sets prices is:

Day Ahead:

> *"Customers are notified each day of forecasted electricity prices for each hour of the following day, then prices are updated each hour, sixty minutes before becoming effective. Prices are based on projections of the hourly running cost of incremental generation (including approved environmental costs), provisions for losses, projections of hourly transmission costs and reliability capacity costs for each day (when applicable), and a two (2) mill/kWh recovery factor. The amount of fuel charges from hourly incremental kWh usage are applied to the recovery of fuel cost at the hourly average marginal fuel cost for the applicable hour."*

Hour Ahead:

> *"Hourly prices are determined each day based on projections of the hourly running cost of incremental generation (including approved environmental costs), provisions for losses, projections of hourly transmission costs and reliability capacity costs for each day (when applicable), and a three (3) mill/kWh recovery factor. The amount of fuel charges from hourly incremental kWh usage are applied to the recovery of fuel cost at the hourly average marginal fuel cost for the applicable hour."*

Under RTP pricing, customers who adjust their electricity demand in response to time-varying prices can reduce their electricity bills and lower system-wide costs, thereby benefiting other customers. In practice, however, charging only marginal-cost prices may not generate sufficient revenue to cover all "fixed" capital expenditures and operating expenses for the utility. To ensure that customers opting into RTP pricing contribute their share to these costs, Georgia Power's tariffs include an implicit fixed charge by pricing deviations from a "customer baseline load" (CBL). The language of the day-ahead tariff states:

> *"The CBL represents a customer's normal operation for billing under its conventional tariff. The CBL is initially developed using either customer-specific hourly firm load data or monthly billing determinant data that represents the electricity consumption pattern and level agreed to by the customer and Georgia Power. Changes in consumption, measured from the CBL, are billed at RTP-DA prices. The CBL is the basis for achieving revenue neutrality with the appropriate non-RTP-DA firm load tariff on a customer-specific basis. Mutual agreement on the CBL is a precondition for use of RTP-DA.*
>
> *For customers with Existing Load, the CBL will initially be developed from either historical metered half-hourly (1/2) interval data for a customer's specific location or from a Template scaled to the historical monthly energy and monthly peak demands.*
>
> *For customers with New Load, the CBL will initially be based on 100% of a Commercial customer's total projected load or 60% or greater of an Industrial customer's total projected load. A new Commercial or Industrial customer can establish a CBL less than its projected level provided that the customer can Demonstrate its desired CBL level or the CBL is based on a Footprint. In no case shall this CBL be less than the minimum CBL level established by Georgia Power for that specific location. Since no historical data exists for a new location, the CBL can be developed from a Template, or from a similar customer's load shape, scaled to the expected usage pattern of the New Load."*

Setting an appropriate CBL can be challenging for new customers and may be subject to gaming (Chao, 2011). New customers are often assigned a low CBL, which has likely contributed to the nominal success of the Georgia Power RTP tariff. Existing tariffs and new opportunities for self-generation, such as rooftop solar and batteries, further complicate this method of setting fixed charges, as customers may anticipate a decrease rather than an increase in their CBL. Consequently, these customers may save more by not enrolling, as they can avoid some contributions to inframarginal and fixed costs that they would otherwise incur if they enrolled in the RTP tariff before their CBL decreased. Conversely, customers planning to increase their demand can avoid these costs by enrolling before their CBL increases.

The variability of renewable supply, coupled with zero fuel costs, can also result in more variable marginal social costs compared to conventional systems with a stable merit order. The calculation of marginal costs will also factor in scarcity rents, which are influenced by the amount of energy in storage and expectations about future supply and demand. Further discussion on the challenges related to gaming the CBL and changes in the nature of marginal costs can be found in Section 5.

2. Proposed Hawai'i Tariff

The proposal is for Hawaiian Electric Company to offer a tariff similar to Georgia Power's, with a few modifications. Critically, because Hawaiian Electric Company does not currently have day-ahead or hour-ahead projections of marginal cost, we propose that Hawaiian Electric Company:

1. Begin publishing in real-time (e.g., each half-hour) system-wide (a) total and net demand, (b) generation mix, and (c) marginal cost, typically calculated as the ``system lambda" by the utility's control system. These should be reported half-hourly or less and posted within minutes of the end of the last applicable time.

2. Develop and vet a methodology for producing day-ahead and hour-ahead projections of (a) total and net demand, (b) generation mix, and (c) system marginal cost, updated hourly as Georgia Power does.

3. Develop and vet a method for nodal pricing (LMP) that uses a power flow model or other means to adjust the marginal cost for each node or circuit on Oahu to account for transmission losses, reactive power, and congestion that may cause marginal cost to vary over the network at a given time.

Instead of day-ahead or hour-ahead projections of marginal cost, participating customers can tentatively pay the actual realized marginal cost instead of the projected marginal cost. In the near term, these customers should be able to develop reasonable expectations of future marginal costs from recent historical patterns, provided that actual marginal costs are published promptly and are easily accessible.

Once Hawaiian Electric Company develops and vets a methodology for forecasting future marginal costs, RTP customers can pay the forecasted hour-ahead or day-ahead marginal cost instead of the actual realized marginal cost.

Qualifying characteristics for participation in the RTP tariff should correspond to existing schedules for Oahu (rather than the criteria set by Georgia Power) and gradually expand over time, starting with the largest commercial customers (Schedules DS and P) and later considering expansion to customers with lower usage (Schedules J, G, etc.). After development day-ahead and hour-ahead projection methodologies, the PUC and Hawaiian Electric Company might consider these expansions. The RTP tariff will only be open to existing customers with at least one year of demand history from which a CBL can be established.

To encourage customers to participate in the program and aid transparency and fairness, the CBL and implicitly associated fixed charges would be based on **95% of a customer's most recent annual use pattern**.[1] To encourage customers to remain on the RTP tariff, the CBL would be reduced **by one percentage point each year that the customer remains on the RTP tariff**. Section 7 shows projected bills for UH Mānoa under this proposed RTP tariff compared to the status quo.

As discussed in sections 5 and 6, this discounted CBL is necessary to entice and maintain the participation of customers who might be planning to reduce their demand via self-generation or other means. Exceptions to this CBL can be considered case-by-case and must be mutually agreed upon by the customer, Hawaiian Electric Company, and the PUC.

3. Compensation for Backfeeding and Off-Site Generation

Given the growth of distributed energy resources and, in some cases, their cost competitiveness with utility-scale generation on Oahu, the tariff applies marginal cost prices to negative demand (e.g., backfeeding). In other words, participating customers may inject clean power into the grid and receive an incremental billing offset or credit equal to the marginal cost of generation multiplied by the amount of energy injected during the hour. Such power injections may come from an off-site facility or from on-site generation that exceeds the customer's demand.

Power flows from off-site facilities will be compensated at the Locational Marginal Price (LMP) at the time and location of injection. If the off-site location has batteries, Hawaiian Electric Company will optimally dispatch the facility and credit the customer's bill at a price equal to the marginal cost at dispatch.

Currently, Hawaiian Electric's marginal cost generally exceeds the levelized cost of new utility-scale solar, making off-site generation economically attractive to participating customers, especially those seeking to reduce their greenhouse gas emissions. The resulting windfall to such customers would help accelerate the clean energy transition while lowering costs for all customers. We propose a profit-sharing rider for off-site facilities to ensure that gains for commercial customers are not disproportionate. The profit-sharing rider would allocate 25% of the net benefits toward reducing other customers' bills and 25% toward Hawaiian Electric's profit. Section 6 explains why Hawaiian Electric should receive a share of the profits. The net benefits would be calculated as follows:

LMP-based monthly revenue - monthly amortized facility cost - O&M

Monthly amortized costs and O&M would need to account for (i.e., subtract) any applicable clean energy subsidies received by the customer (e.g., a production tax credit). These subsidies may exceed actual costs and therefore reduce compensation. Monthly credits to the customer would equal:

0.5 X LMP-based revenue + 0.5 X monthly amortized facility cost + 0.5 X O&M

The customer would establish facility operations and maintenance costs upfront and amortize them over a contracted lifetime. Only the LMP-based revenue would vary over time. After the facility is paid for at the end of its amortized life, monthly credits will equal:

0.5 X LMP-based revenue + 0.5 X O&M

Section 7 reports estimates of what these credits would look like for an off-site solar facility that the University of Hawai'i could build. The simulation uses a model to project how marginal cost will change as Oahu transitions to 100% clean energy by 2045 and uses the University's current plan for on-campus generation to benchmark implications of the current tariff.

4. Benefits of RTP

Given an appropriate Customer Baseline Load (CBL) and customers capable of shifting demand from high-cost to low-cost times, the proposed Real-Time Pricing (RTP) tariff creates a "win-win" for both participating and non-participating customers. Participating customers will reduce demand when prices are high and increase demand when prices are low, thereby reducing their bills relative to the CBL baseline. Collectively, these customers reduce demand during expensive times and increase it during low-cost times, which helps to lower average costs and bills for non-participating customers.

Studies indicate that the benefits from RTP have been modest in conventional electricity systems dominated by thermal fossil fuel power plants (Borenstein, 2005). The reasoning is that, in conventional systems, marginal cost varies little except during periods of very high "peak" demand, which are rare. The savings amount to modest reductions in the capital expense of less-needed peaking power plants, plus occasional differences in fuel costs between peaking and baseload power plants. Borenstein and others estimated the potential savings to be 5% or less of the total cost. RTP may also help limit the anti-competitive practice of withholding power during constrained times to drive up prices in wholesale markets (Borenstein et al., 2002). However, such benefits are irrelevant to Hawaii, which has no wholesale market.

Studies indicate that the benefits from RTP have been modest in conventional electricity systems dominated by thermal fossil fuel power plants (Borenstein, 2005). The reasoning is that, in conventional systems, marginal cost varies little except during periods of very high "peak" demand, which are rare. The savings amount to modest reductions in the capital expense of less-needed peaking power plants, plus occasional differences in fuel costs between peaking and baseload power plants. Borenstein and others estimated the potential savings to be 5% or less of the total cost. RTP may also help limit the anti-competitive practice of withholding power during constrained times to drive up prices in wholesale markets (Borenstein et al., 2002). However, such benefits are irrelevant to Hawaii, which has no wholesale market.

The rapid growth of renewable energy dramatically increases the value of RTP because marginal cost will become much more variable. Often, the marginal cost will be zero, and expensive times will depend less on demand and more on how weather affects supply. A comprehensive study of Oahu's system indicates that the value of RTP is 6-12 times greater in a 100 percent renewable system than in a conventional system, holding demand responsiveness and other assumptions fixed (Imelda et al., 2023). The benefits of RTP are more significant the more responsive demand is to changing prices, which can be enhanced with emerging automation managed by artificial intelligence. While the benefits are uncertain, they are undoubtedly positive and potentially transformative: RTP could make a 100% clean system the most cost-effective, even excluding the higher environmental costs of fossil generation.

In addition to the variable nature of RTP incentivizing efficiency-enhancing demand shifting, the proposed tariff would eliminate incentives to inefficiently self-generate because self-generation would be compensated at its incremental value rather than at conventional rates that far exceed its value. Simultaneously, it would open up new opportunities for low-cost, independent generation from smaller utility-scale operations built by large customers to offset their existing bills. These measures should reduce costs and accelerate the clean energy transition.

5. Answers to Technical Questions

What is Marginal Cost?

The social marginal, or incremental, cost of power refers to the additional cost of producing and consuming the last kilowatt-hour over a short period (e.g., seconds). In a conventional system, this typically includes the cost of extra fuel burned at the power plant that supplies the last kilowatt-hour, line losses in the transmission and distribution system, and any external environmental costs from burning the additional fuel. However, in modern systems with storage and intermittent renewables, the social marginal cost often differs from this traditional measure.

Marginal cost varies over time and location, influenced by environmental factors that affect supply and demand. For instance, demand usually peaks during hot weather due to heavy use of air conditioning. Special events or holidays can also cause spikes in electricity demand, straining the system's capacity. In conventional systems dominated by fossil-fuel-burning thermal power plants, demand variation primarily drives changes in marginal cost. Unexpected plant outages can also impact marginal cost. Efficient operation typically follows a merit order, using power plants from the lowest incremental cost (historically coal and nuclear) to the highest, generally combustion turbines and diesel generators. Power plants at the top of this merit order tend to have high "fixed" capital costs and low running costs, while those lower in the order have low capital costs but very high fuel costs. As total demand exceeds the supply from low-fuel-cost plants, marginal cost rises. The ability of power plants to ramp up or down in response to changing demand varies, with those able to ramp faster generally incurring higher incremental costs. In a conventional system, marginal cost equals the incremental cost of whichever power plant is marginal at the time, which tends to be higher when demand is higher.

How does renewable energy change the calculation of marginal cost?

Solar, wind, and storage significantly alter the conventional calculation of marginal cost in complex ways. Solar and wind energy have zero incremental costs since they incur no fuel or variable operations costs. However, their supply is highly variable and uncontrollable, leading to weather-driven fluctuations in both supply and demand. This variability, combined with zero incremental cost, makes real-time pricing (RTP) especially valuable in systems with high renewable penetration. These factors also complicate the calculation of system marginal cost, which can confuse stakeholders and regulators.

Many express concern that marginal-cost pricing in systems dominated by fixed costs and lacking fuel costs might not generate sufficient revenue to cover the underlying fixed costs. This concern is understandable, given that fuel costs and thermal power plant efficiencies have historically underpinned marginal cost metrics. However, this fear is misguided. While the system marginal cost in a grid with a high share of renewable energy will often be zero, it won't always be, even without fuel costs. If system capacities are optimized, marginal cost pricing will recover all capital costs.

Instead of being tied to fuel burn rates, system marginal costs in high-renewable systems with storage are equal to the opportunity cost of using one more kilowatt-hour at a given moment versus saving the energy for later (i.e., storing it in a battery). Therefore, the system's marginal cost will be zero whenever some renewable energy must be curtailed (discarded) to maintain system balance. In this scenario, consuming one more kilowatt-hour means one less kilowatt-hour is discarded, resulting in a marginal opportunity cost of zero.

How can it ever make sense to discard energy?

Curtailment is an important management strategy that can occur for several reasons. While currently uncommon (except on Maui), curtailment happens when renewable supply exceeds demand and the surplus cannot be stored because storage is full, necessitating the curtailment of surplus energy. Curtailment can also occur when renewable energy makes up a smaller share of the generation mix if there is little storage, and conventional thermal power plants must be kept online to provide reserves and manage ongoing variability in supply and demand. Since thermal plants generally have a minimum operating capacity, curtailment of renewables occurs when their supply exceeds demand net of the minimum generation from operating thermal plants.

The critical observation is that while curtailment often makes sense in a high-renewable system, charging a price above zero during curtailment does not, because the marginal social cost of using more clean energy is zero. In fact, a negative price can be reasonable if a customer using otherwise curtailed clean energy reduces their consumption from a costly or polluting source at another time.

In the future, as renewables and batteries become cheaper relative to fossil fuels and constitute a growing share of the generation mix, the optimal portfolio is likely to include ample renewables to meet demand even on cloudy and less windy days. During especially windy and sunny times, supply will be so plentiful that marginal costs will likely be zero. An irony is that renewable energy will recover most of its costs during cloudy days with little wind, as these will be the days with the highest marginal costs and prices. An optimization study of Oahu, considering thousands of potential technology and policy scenarios, indicates that between 25% and 30% of hours will have zero marginal cost (Imelda et al., 2023). This share will be greater, and marginal costs will be even more variable, in a system without RTP. Thus, a significant benefit of RTP, besides cleaner air, is the opportunity to provide free energy during times of abundance while reducing capital costs by limiting demand during the most challenging times to serve.

What is the marginal cost if demand exceeds the capacity of the system?

Even the most robust system may occasionally face situations where generation capacity cannot meet demand for various reasons. During these times, utilities implement "rolling blackouts," which cut off power to some customers to maintain system balance. These policies are extremely costly, and the risk associated with such events is relevant to calculating marginal costs at other times. It would be preferable to ration all customers to a lower level of use rather than cutting some customers off entirely. Real-time pricing (RTP) can achieve this if a sufficiently large share of the customer base participates and responds rationally to higher prices. While full participation and responsiveness to RTP may not eliminate blackouts, partial participation can reduce their frequency, lowering overall costs and increasing system benefits.

When variable prices curb demand to match constrained supply, marginal cost includes a scarcity rent in addition to the usual fuel and environmental costs of the marginal generator (Figure 1). During a rolling blackout, a high marginal cost should be assigned, probably around $1 to $10 per kilowatt-hour, known as the value of lost load (VLL). This value effectively serves as a maximum marginal cost and should be set by regulatory policy, given its importance in system planning and operations.

Conceptually, the VLL is the loss of consumer surplus to customers who are not served during a rolling blackout, or total willingness to pay minus the amount that would have actually been paid. In principle, VLL varies across individual customers and empirical evidence is limited, as reviewed by Gorman (2022). Those with extremely high VLL, like hospitals, will have their own backup power and are not likely to be affected. Given uncertainty about VLL and other factors, like the possibility of customers inadvertently consuming more than they would like when price and marginal cost equals VLL, this number should be set administratively by the PUC.

How does storage affect marginal cost?

Storage alters the nature of marginal cost by creating scarcity rents below the capacity constraint. Storage smooths supply by transferring power from times of abundance to times of scarcity. Efficient management of storage assets requires forecasts about future supply and demand and measures of uncertainty regarding such forecasts. Critically, storage decisions and expectations about the future influence current scarcity rents and marginal costs. All else being equal, including current and prospective future demand and supply, marginal cost will be higher when the inventory of stored power is lower. In other words, prices should rise as energy stores are depleted, holding all else constant.

Given the rapid growth of storage assets, especially batteries, the complexity of optimally managing storage, and the relevance of these decisions to marginal cost, it is crucial for Hawaiian Electric to make its storage management rules transparent and to vet these rules and forecasting methodologies. Many are working on developing software to optimize operations, including storage for high-renewable systems. For example, a recent working paper by Jacob Mays (2023) provides some technical guidance. The software used to manage the system will report real-time marginal costs, much like the current software. Reporting this marginal cost at regular intervals would be prudent and straightforward.

What does marginal cost look like historically?

Historically, marginal cost has primarily varied with oil prices and has been lower than per-kWh rates on all standard tariffs (see Figures 2 and 3). As a result, incremental prices have generally been too high, mainly because they include non-fuel capital and management costs that are not recovered through marginal-cost pricing. Marginal cost would occasionally fall during low-demand times when marginal generation shifted to newer independently-owned power plants, Kalealoa and AES. Kalealoa, responsible for nearly 25% of the power sold by Hawaiian Electric, also burns oil but is more efficient than Hawaiian Electric's power plants. AES, which burned coal, was considerably cheaper but was retired in 2022. Kalealoa and AES would become marginal when Hawaiian Electric's power plants were either off or operating at minimum capacity. Now that AES has retired and Hawaiian Electric's plants are almost always marginal, marginal cost varies little except when Hawaiian Electric's fuel prices change. This pattern should change substantially as more grid-scale renewable energy and batteries come online.

What will marginal cost look like with more intermittent renewables and storage in the future?

As explained above, marginal cost in a system with a high share of intermittent renewables and storage is more complex. As more grid-scale solar and batteries come online, Kalealoa is likely to be marginal more often, and there may be more instances when it and other backup power plants are ramped down to minimum operating levels because renewable supply is ample and batteries are fully charged. At these times, marginal cost will fall to zero or even negative if marginal cost accounts for clean energy subsidies or environmental costs of fossil fuel substitutes. Thus, marginal costs will drop substantially and become much more variable than in the past, generally ranging between zero and the incremental running cost of Hawaiian Electric's power plants. When this happens, the value of shifting demand from high-cost times to low-cost times will become significantly more valuable.

As Oahu progresses toward 100% renewable energy, marginal cost may often include a scarcity rent that is inversely related to the amount of energy stored in batteries, hydrogen, and other storage methods. Scarcity rents and marginal costs will also depend on future demand and expectations of renewable energy supply. For example, half-full storage capacity would imply a considerably lower marginal cost if the next day's forecast were sunny and windy rather than cloudy and windless, assuming demand expectations remain constant. Therefore, forecasts about future weather will be crucial for current system operations and calculating current marginal costs.

The graph in Figure 4 illustrates what marginal cost ("final price" in the graph) might look like in an optimized 100% renewable system of the future with modest participation in an RTP tariff, based on a study by Imelda Fripp and Roberts (2023). The study considers hundreds of alternative scenarios that vary in assumptions about technology costs, customer demand, and alternative policies. Interested readers can view these scenarios on an interactive website. One critical difference between the prices depicted in Figure 4 and what would happen in actual practice is that the displayed values represent long-run marginal costs in a fully optimized system with perfect foresight. Utilities cannot adjust capital during real-time operations, and there will be uncertainty about future demand and weather-driven supply. This uncertainty will slightly alter marginal costs from those depicted and will require sophisticated forecasting and operations software, as described above.

Should prices be set to long-run or short-run marginal cost?

There are different interpretations of what "marginal cost" pricing entails, with some, notably the Regulatory Assistance Project (RAP), advocating for the use of long-run marginal cost (LRMC) instead of short-run marginal cost (SRMC), which reflects the actual real-time opportunity cost of one kilowatt-hour at any given moment.[2] LRMC is conventionally defined as the lowest marginal cost when all inputs, including power plants, storage, and other fixed infrastructure, are co-optimized with fuel and other short-term variable costs. However, LRMC is a hypothetical real-time concept because it is impossible to build new capital instantaneously. Despite this, LRMC can be useful for system planning. For both SRMC and LRMC, the definition of marginal cost is clear: economically efficient prices are equal to SRMC.

The primary concern is that setting prices equal to SRMC may not cover all capital costs. A shortfall could occur if system capacities exceed what is necessary. Conversely, SRMC could generate more revenue than needed to cover capital costs, resulting in a surplus. This would happen if too little capital were installed, capacity frequently fell short of demand, scarcity rents were too high too often, or rolling blackouts occurred regularly, causing the SRMC to equal the value of lost load too frequently. SRMC will equal LRMC only if the capital infrastructure is precisely optimized, which is unlikely at any given time.

The basic economics is straightforward: In the short run, the socially optimal price is SRMC, regardless of whether capital is overbuilt, underbuilt, or optimally configured (Anderson & Bohman, 1985; Della Valle, 1988; Borenstein, 2019[3]). This is easy to prove: if customers' marginal willingness to pay for the last kWh exceeds the SRMC, then a net gain equal to the difference is accrued by producing that unit and allowing customers to consume it at a price equal to the SRMC. Conversely, if the marginal willingness to pay is less than the SRMC, it is better to save the expense of that last kWh and reduce consumption. This holds true even if the LRMC is greater than the marginal willingness to pay, as LRMC has no bearing on the cost at a particular moment. If utilities recover too little revenue by charging SRMC at all times, it implies that the underlying assets are overbuilt and partially obsolete. This situation signals to regulators and the utility that excess capital exists. Under prudent management, demand will grow, or assets will be retired in the long run.

Similarly, if SRMC exceeds LRMC but the price is set at LRMC, demand will exceed the system's capacity. Excessive rolling blackouts or unserved demand would be overly costly compared to charging a higher price equal to the SRMC. If excess revenues are collected because SRMC exceeds LRMC, it signals to regulators and the utility that capacity should expand.

A salient example illustrates the point concretely. Suppose solar and wind energy are being curtailed because impending investments in battery storage are not yet completed. In that case, the opportunity cost of using more electricity (SRMC) is zero. If the price is 40 cents per kWh, typical on Maui where curtailment often occurs, while customers are willing to pay only 10 cents per kWh for energy that would otherwise be discarded, the waste amounts to 10 cents per kWh discarded. After batteries are installed, the opportunity cost might not be zero on a similar day, as using one more kilowatt-hour would mean one less kilowatt-hour stored for later use, which could be worth more than zero. However, this future scenario does not justify wasting potentially valuable energy generated in the present, which happens whenever prices exceed short-run marginal cost. Similarly, whenever prices exceed or fall short of SRMC, waste occurs. The concept that socially efficient pricing equals SRMC is uncontroversial and is explained in every introductory economics textbook.

Nevertheless, there are many reasonable concerns about SRMC pricing. Given the imperfect regulatory process governing investment and operations decisions, these concerns include questions about measurement and operations management and whether marginal cost pricing will recover costs. Some also worry whether residential customers on RTP are fully informed or aware of current prices and might inadvertently consume more than they would like amid an unexpected price spike. Utilities and regulators can address these issues without imposing the inefficiencies of non-marginal-cost pricing. This proposed tariff is directed toward large commercial customers who are unlikely to suffer from inattentive use as some residential customers might. It addresses cost recovery with fixed charges implicit in the CBL. It may also be sensible to implement a reasonable price cap so that inattentive customers are not punished too severely for their inattention. Price caps can also limit market manipulation during difficult-to-serve times. However, such price limits may require some cost recovery from fixed charges, as implicit in the proposed CBL.

Addressing perceived problems by claiming efficiency is achieved through prices equal to LRMC or an alternative definition of LRMC simply gets the microeconomics wrong. Worse, it obscures the actual issues that need to be addressed forthrightly.

Shouldn't the CBL be adjusted as the customer's demand changes?

No. The CBL must remain fixed indefinitely. Otherwise, the effective price would no longer be the short-run marginal cost. Customers would anticipate a changing CBL and work hard to manage the CBL just as they currently manage demand in response to incentives in the DS and P tariffs. In other words, the benefits of RTP would be diminished, if not eliminated. Note, however, that while the CBL is fixed, the prices attached to the CBL, including demand charges, RBA adjustments, and other factors that affect rates over time, are not fixed.

Won't the reduced CBLs cause costs to be shifted to other customers?

RTP is a win-win for everyone if the CBL is set to what participating customers would have consumed if they had not participated. Since this counterfactual is unknowable, we cannot predict the extent of any cost shift. However, we know that customers have opportunities for self-generation, which tend to be more cost-effective than Hawaiian Electric's avoided costs of not serving them, yet are still lower than the incremental prices under the standard tariff. This provides a strong incentive for customers to reduce demand, particularly those with the capability for self-generation, such as rooftop solar and batteries. In other words, there will likely be more cost shifts without a reduced CBL than with one or without RTP altogether. Therefore, we propose that the CBL be set at a baseline lower than historical consumption. Reduced CBLs are necessary to entice these customers to participate and not engage in self-generation or load shifting unless it reduces overall system costs.

A critical social benefit of this proposed tariff is reducing inefficient exits from the system while lowering the cost of managing intermittent clean power. Over the long term, the cost savings from RTP customers shifting demand in response to changing prices will reduce costs for other customers. However, given the uncertainty about the size of these responses, it is difficult to determine how much other customers will gain.

It is also important to consider that as marginal costs become more variable, substantial rents will accrue to inframarginal generation, transmission, and distribution when energy is relatively scarce. These rents will help recover capital costs. As noted above, if system capacities are genuinely optimized, marginal cost pricing will recover all generation, transmission, and distribution costs, reducing the importance of CBLs over time. Therefore, in the long run, the impact on other customers will depend on investment and regulatory decisions, not just on how much customers respond.

Better counterfactuals than a historical baseline would be scenarios where there is no CBL discount or no RTP tariff. In these cases, customers would be more incentivized to self-generate, shifting costs to other customers. We propose the modest discount described above to encourage initial participation and limit inefficient self-generation and cost-shifting. The PUC could adjust CBL discount incentives as they learn more about participation rates and how customers change their use patterns in response to lower and more variable incremental prices. Section 6 describes additional challenges with the CBL.

6. Challenges of RTP

Gaming the Customer Baseline Load by Customers and the Utility

Successful implementation of the proposed RTP tariff requires sufficient participation and CBLs that reflect, as accurately as possible, the demand profiles that participating customers would have exhibited had they remained on the standard tariff. These two requirements are interrelated. The critical challenge is that the counterfactual—the electricity usage customers would have exhibited had they not participated—cannot be known. Advantageous selection into the program (or opting out) may limit participation, cause inefficient exits from the grid, and lead to excessive shifting of costs among customers.

Consider, for example, a commercial customer planning to grow its demand in the future. For this customer, participating in the RTP tariff is desirable because they can use their historical consumption to set their CBL, thereby locking in a low contribution to fixed and inframarginal costs. In this case, even if the customer consumes precisely what they would have consumed had they not participated in RTP, they will have lower utility bills. Eventually, the difference would be absorbed by other customers. In practice, it would be difficult to detect such customers since marginal costs tend to be lower than average prices, and the customer would have a strong incentive to grow its demand under RTP, even if they would not have done so under the standard tariff. In other words, it is impossible to judge what customers would have done by observing what they do when prices change.

Conversely, consider a commercial customer with the ability and willingness to adjust demand in response to changing prices but who otherwise plans to reduce demand in the future, perhaps through significant investments in energy efficiency or self-generation, as the University of Hawai'i plans to do. Such customers may be hesitant to participate, as doing so would lock in a higher effective fixed charge. The savings from adjusting demand in response to varying prices may be less than those from a lower contribution to fixed and inframarginal costs.

This kind of gaming of the CBL has contributed to the success of Georgia Power's RTP program. Consider an extended quote from the report referenced above about participation in Georgia Power's RTP program:

> *A substantial portion of Georgia Power's C&I customers have chosen to participate in RTP. Overall, 43% of eligible customers and 82% of eligible load was enrolled in one of the two RTP tariffs in 2004. The market penetration rate for RTP-HA alone was even higher, with more than 90% of eligible customers and eligible load participating. RTP has been popular among all C&I customers, but it has had a particularly strong draw among new Georgia Power customers, since they are able to receive a reduced CBL when they enroll in RTP. Of the new customers that Georgia Power signs up each year that are eligible for RTP, typically 70-80% enroll in RTP (GPC 2004b). In comparison, the market penetration rate among customers that were previously on a different rate (and thus have not generally had the opportunity to receive a CBL below their historical firm load level) is closer to 25% (GPC 2004b).*

Georgia Power's characterization of the CBL leaves room for negotiation. They have provided low CBLs for new commercial and industrial customers. This design entices significantly higher participation rates from new customers and likely attracts some commercial and industrial customers to relocate their business operations to Georgia. Consequently, this tariff design encourages broader power sector growth and helps Georgia Power justify building new sizable base-load power plants to serve large commercial and industrial customers. Such growth also provides Georgia Power with a source of profit from the regulated utility's high allowed rates of return on new capital investment. Indeed, the success of RTP pricing programs appears to be highly dependent on buy-in and benefits to the utility (Barbose et al., 2004; Goldman et al., 2006).

The situation in Hawai‘i is roughly the opposite of Georgia Power's. Given its isolation and high electricity costs, the state is unlikely to attract large new commercial and industrial customers with lower electricity prices. Even if such customers could be attracted, Hawaiian Electric may have less to gain from such expansion since most new power plants are competitively bid and are likely to be built by independent renewable energy developers. However, Hawaiian Electric has requested approval of a supplemental capital allowance (and allowed rate of return) to upgrade the distribution grid and retrofit its large Waiau power plant. It is unclear whether RTP could help justify or undermine such requests. On the one hand, flexible demand and efficient use of distributed storage and generation facilitated by LMP might manage congestion on the existing grid at a low cost, potentially displacing Hawaiian Electric's proposed investments. On the other hand, LMP pricing could increase demand and reduce load defection, which might help justify the proposed Waiau retrofit.

Regardless, Hawaiian Electric will need an incentive to embrace real-time pricing. Therefore, we propose sharing profits from off-site facilities with them and other customers. Current incentive mechanisms that reward Hawaiian Electric for a faster transition to renewable energy, growing distributed resources, and reducing costs should enhance this incentive.

A central concern is not load growth but inefficient load defection. Customers now have new opportunities to reduce demand by improving energy efficiency or self-generating. Commercial and industrial customers can also employ batteries, thermal storage, and other emerging technologies to flatten their demand profiles, thereby reducing charges connected to peak demand, which constitute a substantial share of implicitly fixed charges tied to the CBL. While this demand flexibility could help lower system-wide costs in a highly renewable system, the University and other customers would use these technologies to flatten their demand profiles under the current tariff. Since the University and other commercial customers' peak demand occurs at midday—the least expensive time to serve—they are encouraged to shift load in a manner that, quite perversely, increases system costs instead of decreasing them.

Given these opportunities to reduce net demand and flatten their load profiles, customers will want to avoid locking in fixed charges associated with a high current demand. These considerations motivate the proposed CBL equal to 95% of a baseline year and annual reductions in the CBL in subsequent years if a customer sticks with the RTP tariff. By investing in self-generation and efficiency before enrolling, these customers could pass far more costs onto other customers than they would under a reduced CBL. Section 7 illustrates this trade-off in our analysis of the University of Hawai'i.

Vetted and Transparent Operations Software and Marginal Cost Calculation

Utilities typically manage their systems using optimization software that minimizes the cost of serving demand in real time, subject to reserve criteria. This software automatically adjusts power plant utilization based on fuel costs, efficiencies, and relative flexibilities. It produces a "system lambda," representing the marginal cost of generation (typically excluding environmental costs and line losses). Our understanding is that the software used by Hawaiian Electric Company re-optimizes the system approximately every five seconds. A reasonable approach to calculating the marginal cost for RTP tariffs is to take the demand-weighted average of this marginal cost every 15 to 30 minutes and report it publicly. These sub-hourly measures could then be averaged to obtain an hourly metric for pricing. Although Georgia Power's tariffs do not explicitly state that the system lambda is used to determine the marginal cost, energy experts familiar with their program indicate that this is the measure used.

Conventional software used for system management may need to be improved for emerging systems with large amounts of intermittent renewables and storage, such as the system developing on Oahu. As described in Section 5 above, optimal system management and determination of marginal cost will increasingly depend on forecasts of future weather and associated supply and demand. Since customers will need to make informed decisions about managing their demand, they must have a clear understanding of how such decisions are made and confidence that these decisions are made prudently. The methods and forecasts for managing the emerging system and determining marginal cost must be vetted and transparent.

7. The University of Hawai'i as a Pilot RTP Customer

The University of Hawai'i is concerned about its high energy bills and aims to reduce its carbon emissions to net zero by 2035, ten years ahead of the State's goal for the electricity sector. The University has a range of potential investments to reduce its bills, including improvements in energy efficiency, on-site generation and storage, and off-site clean energy generation and storage. It has already begun making these investments. While these investments reduce the University's bills and emissions, under current billing structures, most of their savings involve transferring costs to other customers, as described above. Additionally, the University's investments in clean energy generally exceed the cost of building clean energy at a grid scale.

For example, the University's recent 2 MW solar panel installation above the parking structure on the Mānoa campus costs 17 cents per kWh under a power purchase agreement. This price far exceeds the cost of recent utility-scale installations, which range between 8-10 cents per kWh and include substantial battery installations, unlike the University's installation, which has no battery. Thus, while the University's solar installation helps achieve its goals of reducing emissions and energy costs, it makes the island-wide and statewide renewable energy transition unnecessarily costly. Much of its savings are simply a transfer of costs to other customers. Assuming the continuation of the DS tariff, current plans include installing up to 24.5 MW of solar and batteries to reduce electricity purchases and flatten the University's load profile to reduce demand charges. The University also plans to improve energy efficiency and alter building utilization, which could combine to reduce electricity use by as much as 39%. Furthermore, the University plans to grow and change building utilization, which could also reduce electricity demand.

The University's reduced energy costs from these on-campus investments will primarily involve cost transfers to other customers. This occurs because the retail price far exceeds the marginal cost most of the time, so the University's savings from reduced demand and lower peaks are much greater than Hawaiian Electric's avoided cost. Under RTP, the University's savings from changing demand would equal Hawaiian Electric's avoided cost, eliminating cost transfers. In this scenario, the University would likely scale down its planned on-campus investments, saving millions of dollars in resources.

Instead of installing solar on campus, the new tariff would allow the University to install grid-scale solar at an off-site location. The simpler, uniform, ground-mounted installation would be far less expensive. If the University can finance the off-site facility using state-issued bonds and benefit from federal subsidies under the Inflation Reduction Act, it could significantly contribute to the State's renewable energy goals while reducing its bills and those of other customers, and increasing Hawaiian Electric's profit under the proposed sharing rule.

In plain terms, the proposed RTP tariff would enable the University to substitute a 25 MW off-site solar installation, costing approximately $25 million, for the nearly $192.5 million required to install an additional 18.3 MW of on-site solar that would generate far less energy. This change would also encourage more efficient demand management on campus. Considering cost and subsidy differences, the net savings exceed $200 million under our relatively conservative assumptions, while achieving greater reductions in greenhouse gas and other pollution emissions.

These benefits to the University, other customers, and Hawaiian Electric Company would be in addition to savings from new efforts to shift demand to low marginal cost times and reduce demand during high marginal cost times, providing further mutual benefits. The University aims to manage energy costs and align its decarbonization efforts with the State's goals for reducing greenhouse gas emissions. The proposed real-time pricing would achieve this outcome.

It is doubtful that the University could self-generate on-site at the Mānoa campus in a manner more cost-effective than the grid-scale options available. The University's administrators are concerned about making investments that may seem economically viable today under the DS tariff but might not make sense if substantive improvements in tariff design, such as the proposed RTP tariff, are implemented. The fact that current rate structures incentivize inefficient load defection casts doubt on their sustainability. It would benefit the University to obtain clear commitments to tariffs that are credibly sustainable over the long term as it transitions to a clean energy system. It is reasonable to expect other large electricity customers to have objectives and concerns similar to the University's.

With this background in mind, we detail what the proposed real-time pricing tariff could look like for the University. Using Switch, an island-wide model for Oahu's power system previously used by Ulupono in regulatory proceedings, we project future costs, standard rates, and hourly marginal costs. We updated the model to account for changes in projected oil prices and a recent increase in the margin between Hawai'i oil fuel costs and world oil prices, as discussed in Section 5 and indicated in Figure 2. We then considered how the Mānoa campus bills would change under their current plan for on-campus solar and optimized battery installations to manage peak loads and limit backfeeding to the grid.

Throughout, we assume that, except for solar and battery installations, Mānoa campus demand will not change. Demand may grow or shrink depending on the balance of building and facility growth and planned energy efficiency improvements. The scale of these changes likely depends on whether and how rates change. Under the proposed RTP tariff, it is more likely that demand would increase compared to the current DS tariff. The impact of rate changes on other customers under RTP will also depend on realized capacity expansion and system upgrades by Hawaiian Electric, how those changes affect marginal costs, and whether other customers are able and willing to adopt RTP.

Projected Future Rates and Marginal Costs

To estimate how rates would change going forward, we updated the open-source model (Switch) developed by Matthias Fripp for Ulupono and used in prior regulatory proceedings. (See: https://github.com/switch-hawaii/ulupono_scenario_2.1). Starting with the existing generation portfolio, the model creates a least-cost capacity expansion plan for achieving 100% clean electricity generation for the island of Oahu by 2045. Then, using the planned system for each planning year (2025, 2030, 2035, 2040, and 2045), we ran an operations version of the model that simulated a full year (8,760 hours) under synchronized weather and demand from 2007, rescaled to projected future demand in each planning year. We used the operations model solutions to infer overall and marginal costs in each hour. The cost and input assumptions are essentially the same as the original study, except that we updated fuel cost projections based on the analysis described earlier.

In Table 1, we report projected rates and marginal costs for each planning year, which we use throughout the analysis.

Because projected system costs are from a least-cost system and not the system that Hawaiian Electric currently plans, the projected costs and prices will likely be lower than the realized costs and prices. The pattern of marginal costs may also differ, as the least-cost system relies more on grid-scale solar and batteries than Hawaiian Electric's plan. While it is difficult to say for certain, these assumptions make the projected benefits of the proposed RTP tariff conservative. In particular, marginal costs are likely higher on average and higher during daytime hours under Hawaiian Electric's plan, making off-site installation more valuable. It would also result in higher projected rates under the DS tariff and greater gains for the University from self-generation without RTP. It will be necessary for regulators to carefully consider these assumptions and the opportunities for self-generation by the University and other large customers when refining key design parameters, such as the discounted CBL.

The Mānoa Campus Energy Plan Under the Status Quo, DS Tariff

As one of Hawaiian Electric's largest customers, the University currently purchases electricity under the DS tariff, which applies to customers with demand exceeding 300 kW and served directly by a substation. The tariff includes a $450 per month customer charge, a demand charge of $23/kW per month—which applies to the average of the previous month's peak 15-minute demand and the last year's 15-minute demand—and a multi-component per-kWh charge that varies month to month depending on fuel costs and other factors. In 2022, the monthly demand charge averaged $368,004, the per-kWh charge averaged $0.35 per kWh, and the average monthly bill was $3,078,676. The per-kWh charge was high in 2022 due to elevated oil prices but was still far above the average marginal cost, approximately $0.22 per kWh (Figure 2).

To reduce its bills and carbon footprint, the University has developed a plan to install 24.4 MW of rooftop solar on campus. Approximately 6.1 MW of rooftop solar has already been installed, and the buildout will progress gradually over the next 20 years. Contracting costs for the University are high, and many installations will require canopies or other structures to support the panels, further increasing costs. Aggregating plans over five-year increments, we summarize the plans in Table 1. A map of the solar plans is shown in Figure 5. Self-generation and batteries will be used to reduce overall demand by approximately one-third and reduce peak demand by over a quarter (Figures 6 and 7), yielding total savings to the University of about $1.85 million per year in 2025 (excluding solar already installed) and up to about $7.5 million per year by 2040 (difference between the first and second bars in Figure 9).

Given the high cost of these on-campus investments, we find modest net benefits to the University. Using a 2% real discount rate, we estimate a net present value of just $7.2 million in net savings to the University (top panel, Figure 12).

Table 1. Summary of planned solar and battery installations on the Mānoa campus and the influence on mean demand and peak demand.

Planning Year	Solar PV (MW)	Battery (MWh)	Cumulative Cost* (Millions $2022)	Mean Net Demand (MW)	Mean Monthly Peak (MW)	DS per-kWh rate	DS per-kW peak rate	Average hourly MC
2022*	6.1	0	0	11.5	14.9	0.35	23	0.22
2025	10.1	2.0	41.8	10.7	13.1	0.20	25	0.14
2030	20.1	5.6	153.1	8.8	11.6	0.24	27	0.07
2035	20.6	6.3	157.2	8.7	11.5	0.24	27	0.08
2040	20.8	7.1	159.3	8.6	11.4	0.25	27	0.08
2045	24.4	11.9	192.5	8.0	10.7	0.12	30	0.11

**We have adjusted the baseline 2022 Mānoa campus demand to 2007 weather to align with the system-wide model of Oahu, which is also based on 2007 weather. We have also collapsed the 15-minute interval data to hourly, slightly underestimating the peak demand to simplify some computations. Average hourly marginal cost (MC) values are weighted by UH Mānoa baseline demand. Projected tariff rates assume optimal capacity expansion going forward using Switch software; future rates and marginal costs may differ from our projections. These assumptions may cause us to underestimate the benefits to UH Mānoa (and the costs to other customers) of self-generation and peak demand reduction under the conventional DS tariff.*

Meanwhile, on-campus generation by UH Mānoa will cause Hawaiian Electric to avoid some generation costs. We approximate these savings using our island-wide model of Oahu referenced above. Starting with an optimal plan for an island-wide transition to 100% clean power by 2045, we simulate hourly operations during each planning year using the optimal portfolio of assets, valuing Mānoa campus generation at the system's marginal cost. These savings equal a small fraction of the University's savings (aqua-colored bars in Figure 9). For example, in 2040, we estimate that Hawaiian Electric will avoid costs of about $1.0 million while the University will save around $7.5 million. The difference, approximately $6.5 million, constitutes a cost transfer to other customers (green bars in Figure 9). In practice, this loss would appear in bills as a higher RBA adjustment and eventually get rolled into standard rates. We estimate the net loss for other customers to equal $121.2 million.

Impacts of the RTP Tariff

This section summarizes the estimated impacts of RTP by combining the effects of the reduced CBL and an off-site, 25 MW utility-scale solar facility on University land in West Oahu.

Under RTP, on-campus solar installations would no longer be worthwhile for the University because Hawaiian Electric would only compensate for reduced demand at system marginal cost rather than the prevailing DS per-kWh rate. Additionally, the University would be incapable of reducing demand charges since these would be tied to the fixed CBL. If the University were to install solar and batteries on campus, they would not influence other customers' bills since the bill reduction would equal Hawaiian Electric's avoided costs under RTP. However, different customers would be affected by the reduced CBL. The University, Hawaiian Electric, and other customers would gain from the off-site solar facility and be compensated at marginal cost for all power provided to the grid.

We do not account for other possible benefits from the University shifting demand in response to variable prices. Because marginal costs will vary significantly and the University has no experience with such pricing, it is difficult to speculate on how significant these shifts may be. By ignoring these shifts, we likely underestimate the benefits of the RTP tariff to all parties.

Figures 9 through 12 summarize the results. We describe the underlying assumptions below. We provide the data and code used in the analysis in a GitHub repository.

Calculating the CBL

Under the proposed RTP tariff, the CBL is derived from a customer's usage over a baseline calendar year. For this analysis, we consider the University of Hawai'i at Mānoa's demand from 2022. We develop a baseline for each hour based on the calendar month average for that hour. For example, the baseline demand for 12-1 pm for all days in January will be the average demand in January 2022 from 12 to 1 pm. These average hourly amounts would then be multiplied by 0.95. The CBL will be calculated similarly for each hour in each month. Per-kWh charges under the standard DS tariff would be applied to the hourly CBL as if it were actual demand.

The demand charge for each month would be fixed and based on the CBL. The demand charge will vary by month and is tied to the average of the highest 15-minute demand (kW) in the CBL month and the highest 15-minute demand in the CBL year. For example, the peak demand for January would be the average of the peak 15-minute demand in January 2022 and the peak demand in the calendar year 2022, each multiplied by 0.95. This kW measure is multiplied by the prevailing demand charge rate under the DS tariff. Changes to rates under the DS tariff would be applied to the CBL, regardless of how the University's actual demand changes.

Each year that the University remains on the tariff, the month-by-hour CBL baseline loads and monthly demand charge values would be reduced by 1%. Except for this annual reduction, the CBL does not change, no matter how the University's demand profile evolves.

Given the CBL, all hourly deviations from the CBL will be priced at the hourly average marginal cost, calculated using LMP, day-ahead or hour-ahead forecasted LMP, or system lambda if LMP calculations are not feasible. If demand is less than the CBL for any particular hour, the University is credited LMP x (CBL - Actual Demand); if demand exceeds the CBL, the University is charged an additional LMP x (Actual Demand - CBL).

An illustration of these calculations is shown in Figure 7 using actual historical demand by the University during two calendar years, 2018 (a high-demand year) and 2020 (a low-demand year due to COVID). We do not discount these CBLs since the point is to show how the CBL affects billing, holding all else the same. We calculate RTP bills each year, assuming the other year is the CBL. This comparison illustrates how the CBL affects bills if demand grows or falls after being established.

The graphs also show what bills would be if the current year were the CBL; in these cases, the bills are almost identical to bills under the conventional tariff since deviations above and below the CBL approximately average zero. In practice, the University would likely develop ways to shift energy use from high-price to low-price periods, reducing costs relative to what's illustrated. The University would also be less inclined to engage in self-generation and excessive energy-efficiency investments, so its demand would more likely grow over time instead of decreasing. The fact that this tariff will influence the University's investments and electricity demand illustrates why the CBL must be fixed over time, no matter how its demand changes.

We use 2022 as the CBL for all further calculations. To align UH demand data with the model data for the island of Oahu, we linked UH demand to weather variables (temperature, day of the week, and hour of the day). We used this link to rescale observed 2022 values to hourly temperature outcomes in 2007, the year of high-resolution weather data used for island-wide energy system modeling.

The Cost of CBL Discounts

Holding demand constant and keeping on-campus solar fixed at current levels, the University's bills would decline with the CBL discounts (5% in the initial year and an additional 1% in each subsequent year). Note that bills would decrease by less than the CBL discount because the tariff still charges a price equal to marginal cost for electricity use above the CBL. The off-white bars in Figure 9 show bills in this case, and the purple bars indicate the impact on other customers. Again, these CBL discounts are provided to incentivize UH Mānoa's participation, eliminating their ability to benefit from on-campus solar installations. It is evident in Figure 9 that for the given CBL discounts, the loss to other customers is considerably less than the losses under the University's current plan with the DS tariff.

Benefits from the Off-Site Solar Installation

Here, we consider the implications of the University building a 25 MW utility-scale solar project and feeding the power into the grid. We evaluate the net benefits of this project under a range of assumptions about costs and subsidies under the Inflation Reduction Act. We do not consider a battery installation, which should ideally be paired with the solar installation. Because our Oahu-wide model already optimizes batteries and solar, the net benefits of a battery installation would likely be modest.

We assume costs ranging from $1 to $1.50 per MWh of installed capacity, which is above current costs, financing costs that range from 3 to 5 percent real (i.e., subtracting inflation from the interest rate), and panel lifetimes ranging from 20 to 30 years. These cost assumptions range from slightly to well above average for current installations in the United States for similar-sized projects, which ought to be conservative given that the University can provide the land and should be able to absorb much of the financial risk. Unlike current utility-scale projects with fixed rates and guaranteed capacities, power supplied from this project would be compensated at marginal cost, with net benefits shared between the University, Hawaiian Electric, and other customers as described in Section 3.

Figures 10 and 11 show the annualized net benefits of such a project. The top panel of Figure 10 shows the average generation and marginal costs per hour of the day in each planning year. Because marginal costs tend to be lower on sunnier days, we also show average revenue by hour of the day in the bottom panel of Figure 10. Figure 11 shows annualized benefits over the range of cost and subsidy assumptions. Even under the most pessimistic cost assumptions, the net benefits are substantial, ranging from roughly two to three million 2022 dollars annually.

Overall Implications of RTP

Figure 12 summarizes the overall results for the current plan, the proposed RTP tariff, and the latter's overall net benefits. The total benefits exceed $200 million, with $93.6 million accruing to the University, $22.2 million to Hawaiian Electric, and $86.3 million to other customers. We believe these estimates are conservative for various reasons described previously. If many schedule DS and schedule P customers adopt RTP under this proposal, the social benefits could reach billions and simultaneously accelerate the State's decarbonization efforts.

Acknowledgment

We sincerely thank Michael Chang, Carlos Perez, Mark Shimabukuro, Peter Young, and other employees of Hawaiian Electric, Miles Topping, Director of Energy Management at the University of Hawaii, and Henry Curtis from Life of the Land, for their invaluable contributions throughout the development of this proposal. Their insights, questions, and feedback on earlier drafts were instrumental in shaping our work, and we are especially grateful for the data provided by Miles Topping. Please note that the views expressed in this proposal are solely ours and do not necessarily represent those of Hawaiian Electric or the University of Hawai'i.

References

Andersson, R., & Bohman, M. (1985). Short-and long-run marginal cost pricing: on their alleged equivalence. *Energy economics*, 7(4), 279-288.

Barbose, G., Goldman, C., & Neenan, B. (2004). A *survey of utility experience with real time pricing* (No. LBNL-54238). Lawrence Berkeley National Lab.(LBNL), Berkeley, CA (United States).

Boiteux, M. (1960). Peak-load pricing. *The Journal of Business*, 33(2), 157-179.

Borenstein, S. (2005). "The Long-Run Efficiency of Real-Time Electricity Pricing." *The Energy Journal*, 93-116.

Borenstein, S. (2019). "Pricing for the Short Run." *Energy Institute Blog*, UC Berkeley, August 19, 2019, https://energyathaas.wordpress.com/2019/08/19/pricing-for-the-short-run/

Borenstein, S., Bushnell, J. B., & Wolak, F. A. (2002). Measuring market inefficiencies in California's restructured wholesale electricity market. *American Economic Review*, 92(5), 1376-1405.

Chao, H. P. (2011). Demand response in wholesale electricity markets: the choice of customer baseline. *Journal of Regulatory Economics*, 39(1), 68-88.

Deaton, A., & Laroque, G. (1992). On the behaviour of commodity prices. *The Review of Economic Studies*, 59(1), 1-23.

Della Valle, A. P. (1988). Short-run versus long-run marginal cost pricing. *Energy Economics*, 10(4), 283-286.

Dixit, A. K., & Pindyck, R. S. (1994). *Investment Under Uncertainty*. Princeton University Press.

Goldman, C., Barbose, G., & Neenan, B. (2006). Real-Time Pricing as an Optional Service: It's Alive, But Is It Well? *The Electricity Journal*, 19(1), 18-29.

Gorman, W. (2022). The quest to quantify the value of lost load: A critical review of the economics of power outages. *The Electricity Journal*, 35(8), 107187.

Imelda, Fripp, M., & Roberts, M. J. Real-time pricing and the cost of clean power. *American Economic Journal - Economic Policy* (forthcoming).

Joskow, P. L. (2007). Regulation of natural monopoly. *Handbook of law and economics*, 2, 1227-1348.

Mays, J. (2023). Sequential Pricing of Electricity. Working Paper, School of Civil and Environmental Engineering, Cornell University.

Scheinkman, J. A., & Schechtman, J. (1983). A simple competitive model with production and storage. *The Review of Economic Studies*, 50(3), 427-441.

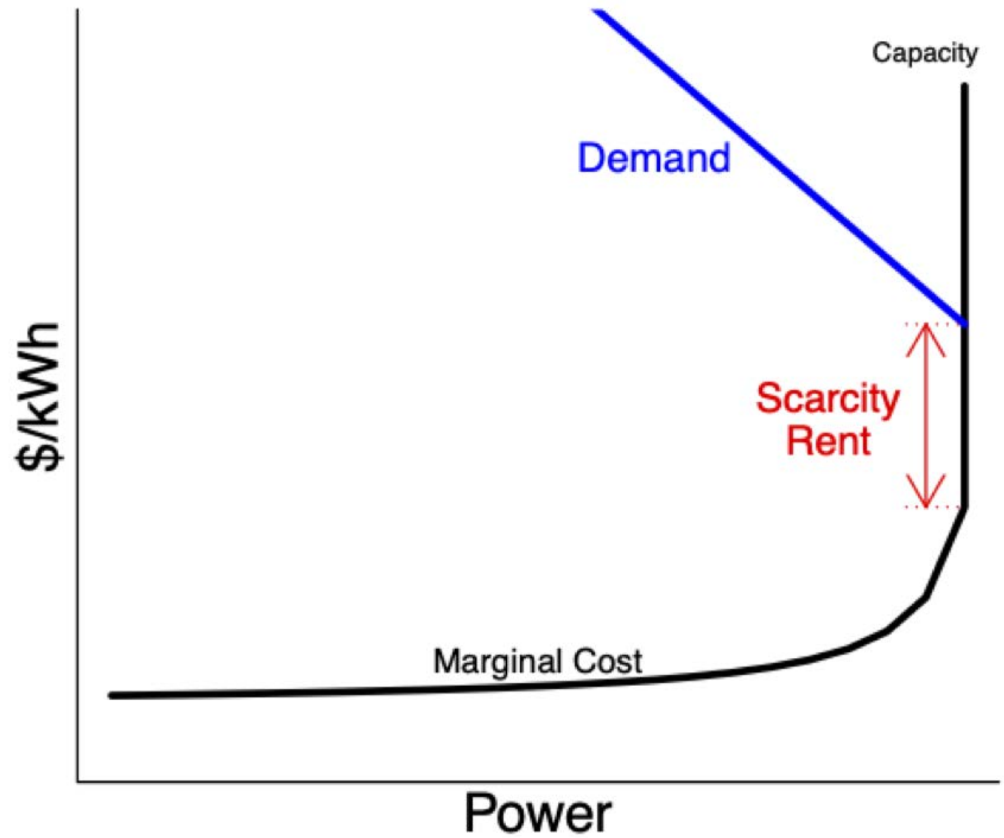
Turvey, R. (1968a). Peak-load pricing. *Journal of Political Economy*, 76(1), 101-113.

Turvey, R. (1968b). *Optimal pricing and investment in electricity supply: An essay in applied welfare economics*. Routledge.

Williams, J. C., & Wright, B. D. (1991). *Storage and Commodity Markets*. Cambridge Books.

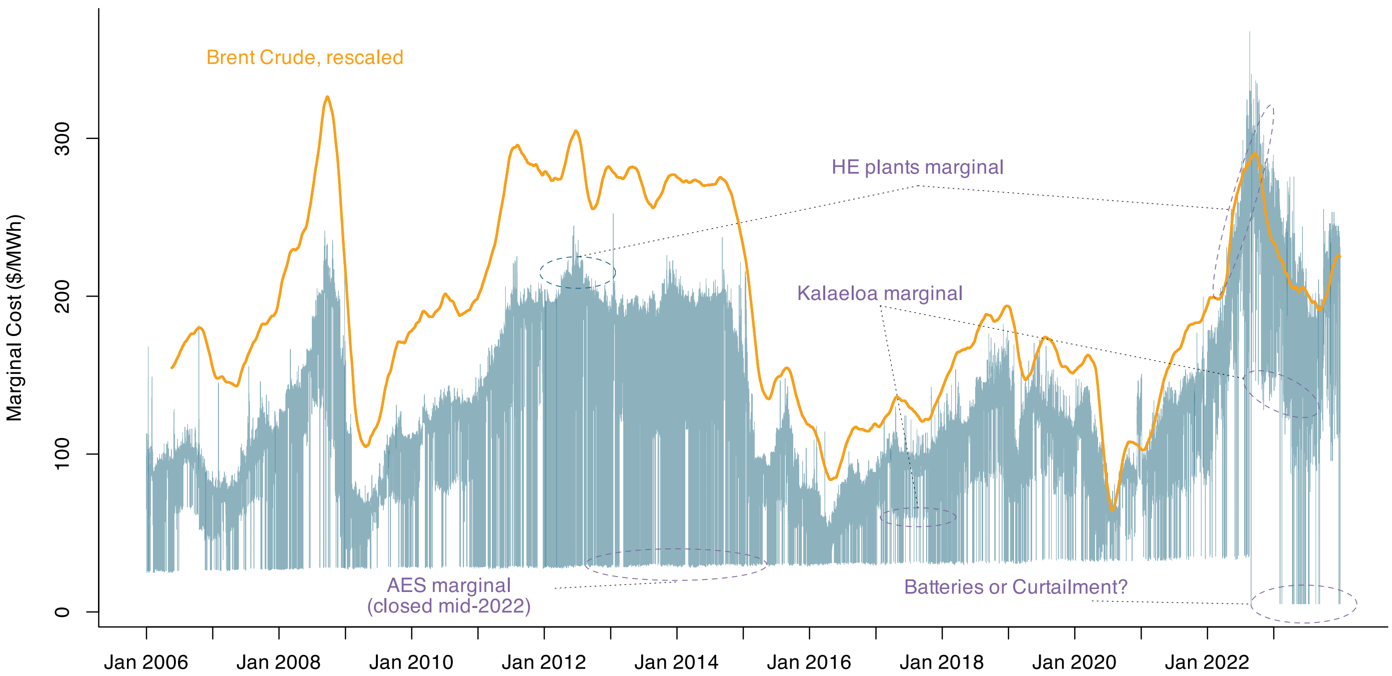
Exhibits

Figure 1. Scarcity rent in a conventional system with RTP when demand exceeds capacity.



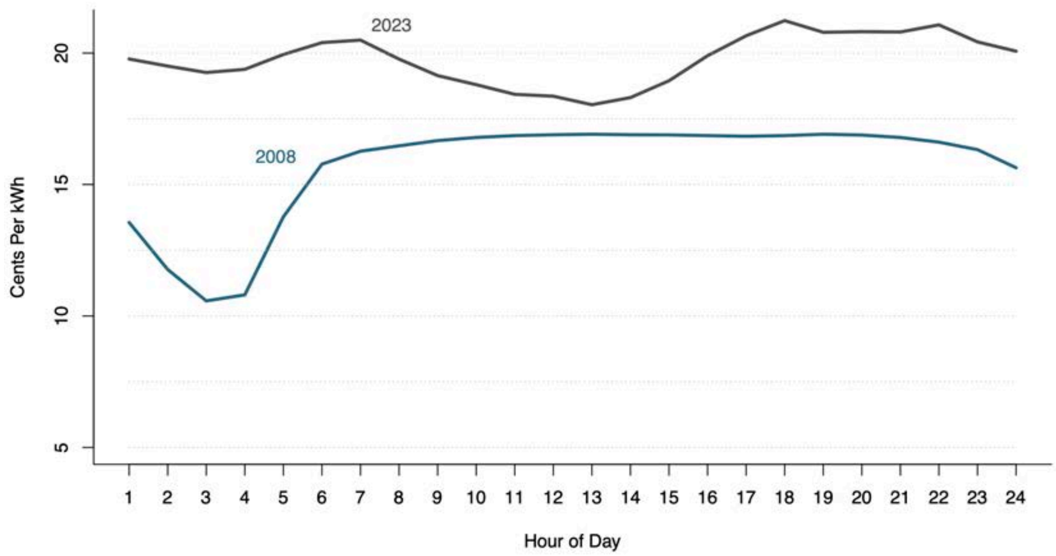
When demand exceeds capacity, the utility employs rolling blackouts to curtail demand so that it does not exceed supply and cause the whole grid to collapse. But if enough customers are on real-time pricing tariffs and are responsive to price, the price can be raised to the point where demand equals available supply. If and when this happens, the system's marginal cost includes a scarcity rent in addition to the physical cost of power generation. In systems with storage, scarcity rents will often exist, not only at peak demand but during normal operations; scarcity rents will vary depending on the amount of available stored energy and prospective future supply and demand. If rolling blackouts occur, the marginal social cost would be the value of lost load (VLL), far higher than the marginal willingness to pay for electricity. Time-varying scarcity rents will comprise much of the marginal cost of high-renewable systems with storage and little or no fuel costs.

Figure 2. Oahu hourly system marginal cost as measured by the system lambda.



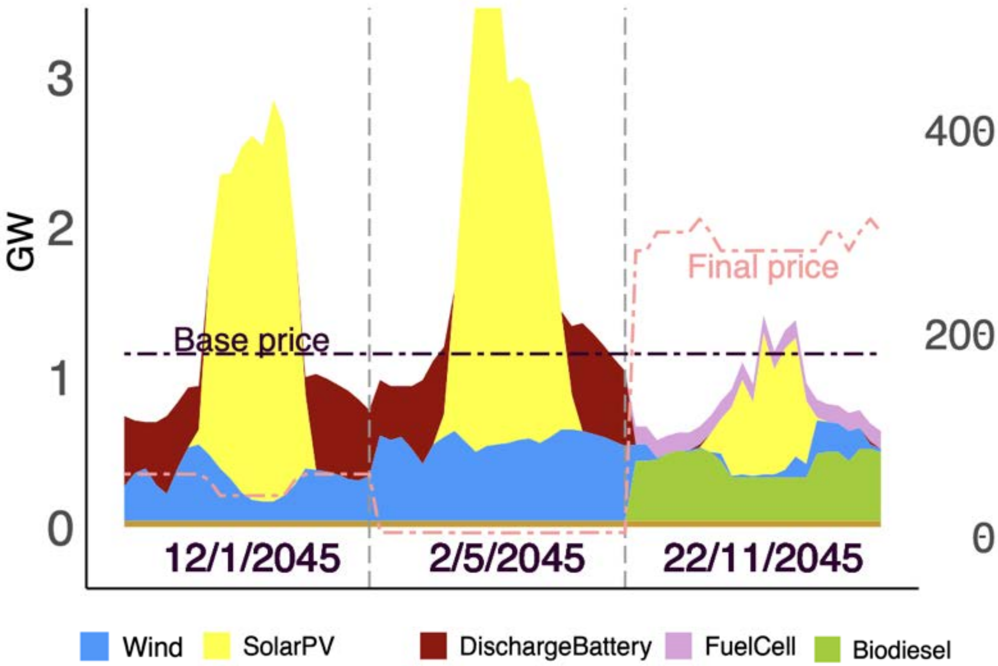
The graph shows all hourly marginal costs Hawaiian Electric reported to the Federal Energy Regulatory Commission from January 2006 through December 2023. The graph also shows (in orange) a 15-week moving average of Brent crude oil prices, lagged by 50 days, which correlates strongly with Hawaiian Electric's inventory cost of fuel. Hawaiian Electric's power plants, which are marginal most of the time, generally have higher marginal costs than independent power producers, Kalealoa and AES (recently retired). Note that marginal costs rose in 2022 by far more than the world oil price. This may have occurred due to the consolidation of the island's two refineries and Hawai'i ending oil purchases from Russia after they invaded Ukraine. It is unclear whether or how long the excess premium on fuel oil costs will persist.

Figure 3. Average system marginal cost by hour of day in 2008 and 2022.



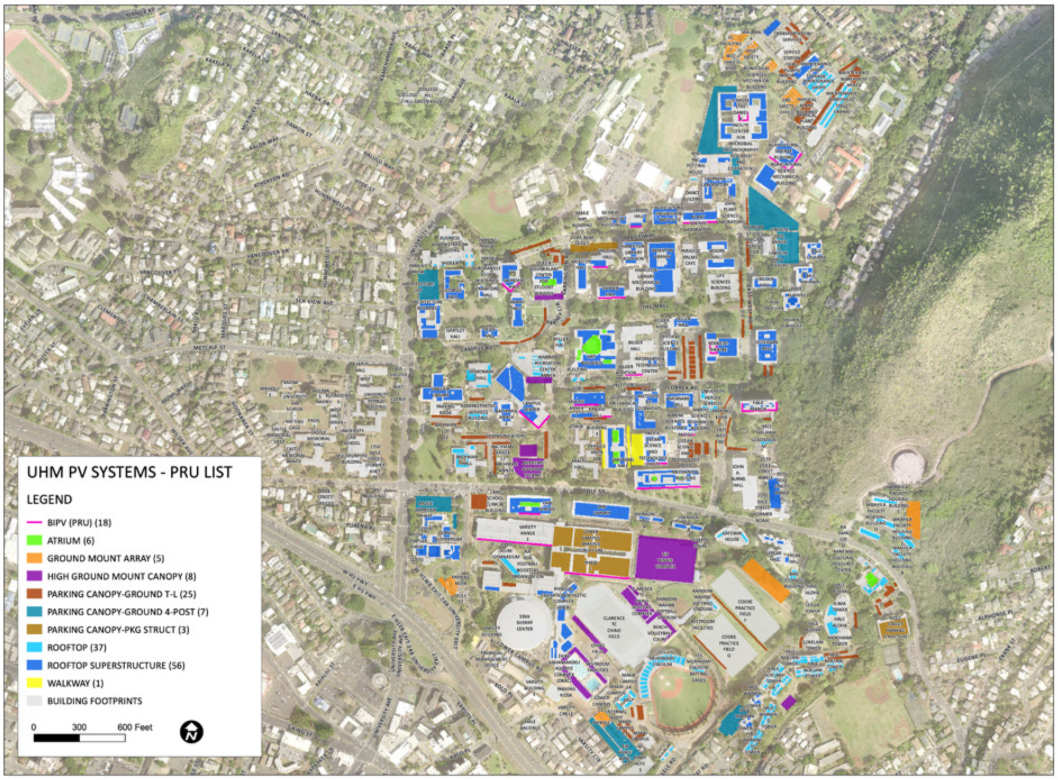
The graph shows the average marginal cost by hour of day in 2008 and 2023. In 2008, the lowest cost times were early morning, when AES would occasionally become marginal, and the high-cost times stretched from late morning through early evening. Today, the least-cost times are midday, but the variation in marginal cost is modest since Hawaiian Electric's oil-fired power plants are almost always marginal after the contract with AES ended. This pattern will change in a system with much more renewable energy and efficiently managed storage.

Figure 4. Generation mix and real-time price in a simulated 100% clean system in 2045.



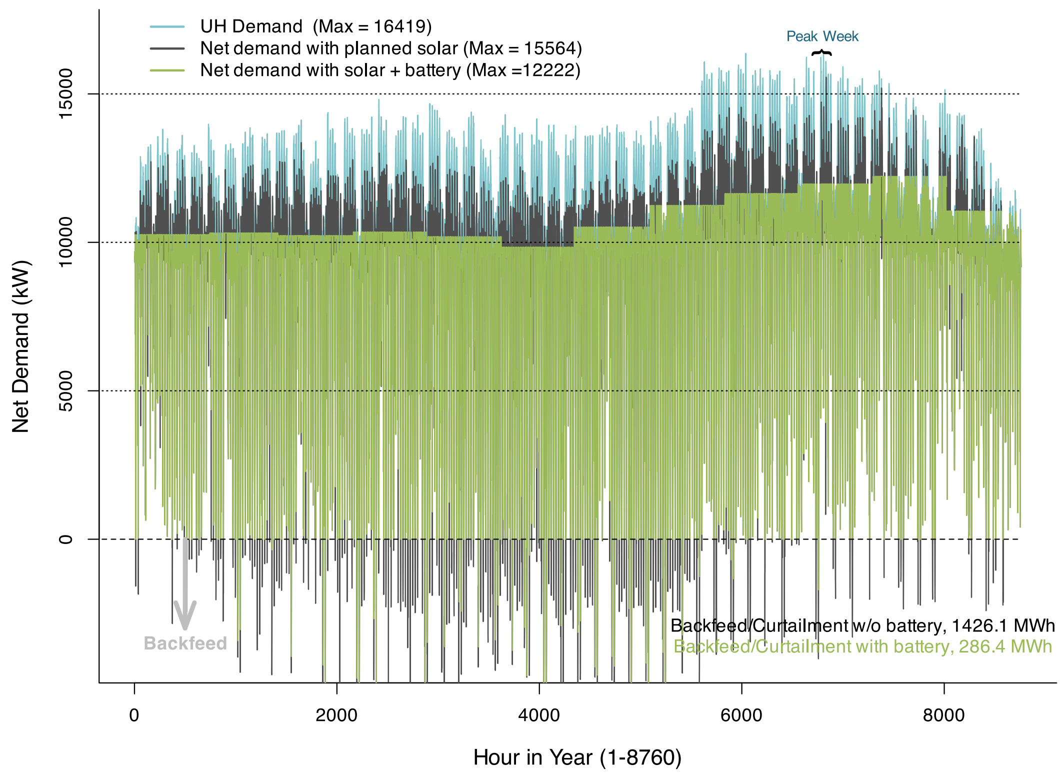
The graph shows the generation mix and equilibrium marginal-cost prices by hour of day for three sample days in a model that finds the least-cost way of achieving a 100% renewable system in the presence of RTP and modestly responsive demand (moderate within-day shifting of demand and an overall demand elasticity of 0.1). The first two days shown are fairly representative, while the third day is rare, the most difficult to serve over two years of high-resolution weather and demand used in the calibration of the model. The price scale on the right side is $/MWh (i.e., 200 implies 20 cents per kWh). Notably, the study generally finds much more variation in marginal cost between days than within, and a large share of hours have near-zero prices. Without RTP pricing and demand response, the variation in marginal cost is projected to be much greater than depicted but has a similar temporal pattern.

Figure 5. Mānoa Plan for On-Campus Solar PV Generation



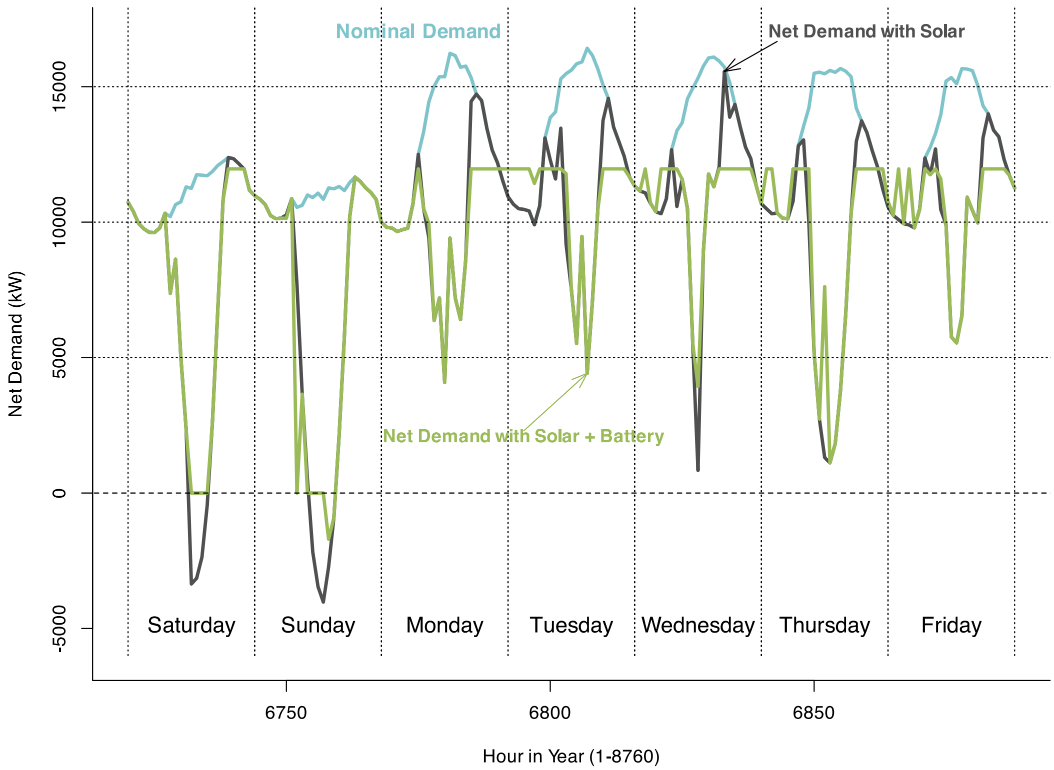
The map shows the University's current plan for rooftop solar installations. Some of the installations have already taken place. Others have already been contracted. Our analysis assumes many installations will not occur if RTP is adopted, but even if they do proceed, future installations would not negatively affect other customers under RTP as they would under the current DS tariff.

Figure 6. Projected changes in Mānoa campus demand with planned on-campus solar and optimized battery installations.



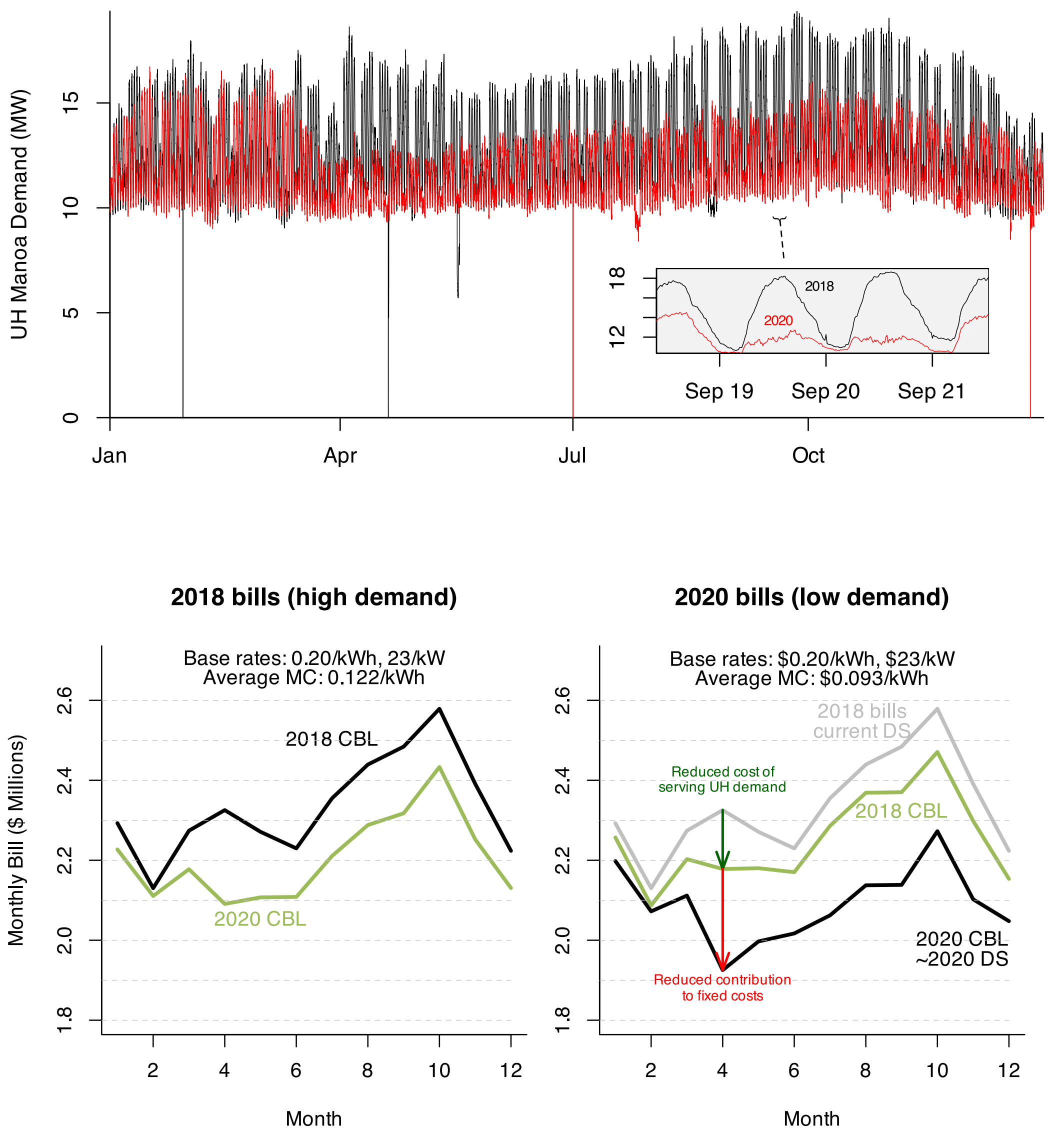
The graph shows projected demand for 2045 paired with planned solar installation (additional 18.3 MW) paired with a roughly 12 MWh battery installation that aids in the reduction of peak loads while minimizing back-feeding, for which we assume UH will receive zero credit. Battery size and hourly operation are optimized using a mixed-integer linear programming model with demand reshaped to match the weather that is synchronized with the Oahu-wide Switch model.

Figure 7. Projected "peak week" changes in Mānoa campus demand with planned on-campus solar and optimized battery installations.



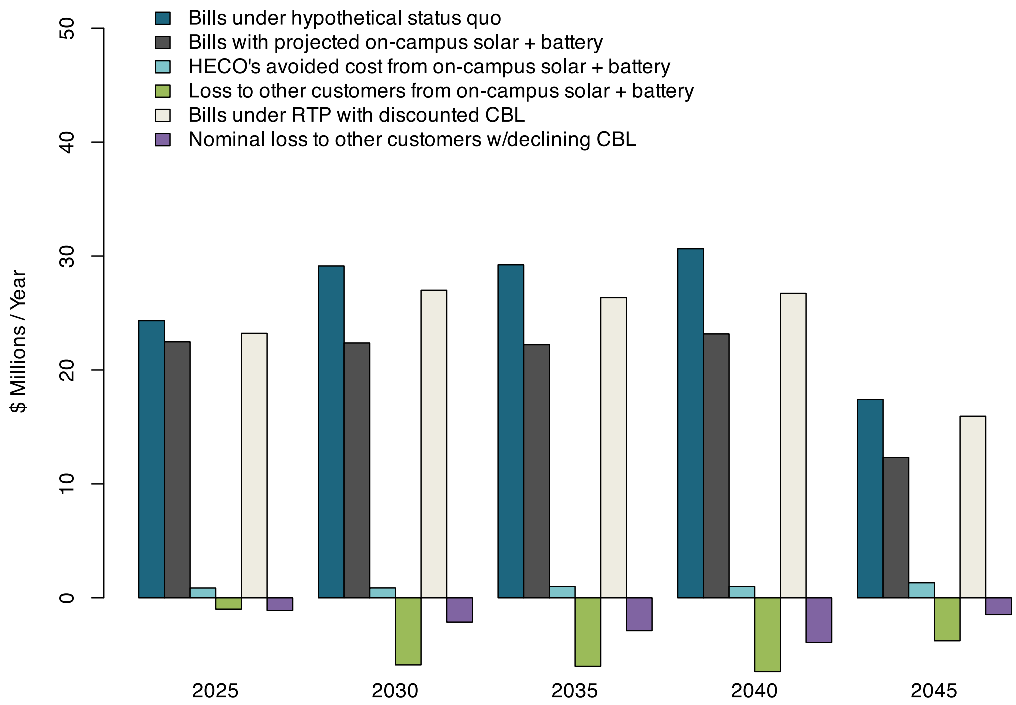
The graph shows a higher resolution of the "peak weak" when UH Mānoa had the highest net demand in the model year (labeled in Figure 6).

Figure 8. An illustration of how the CBL affects bills under the proposed RTP tariff



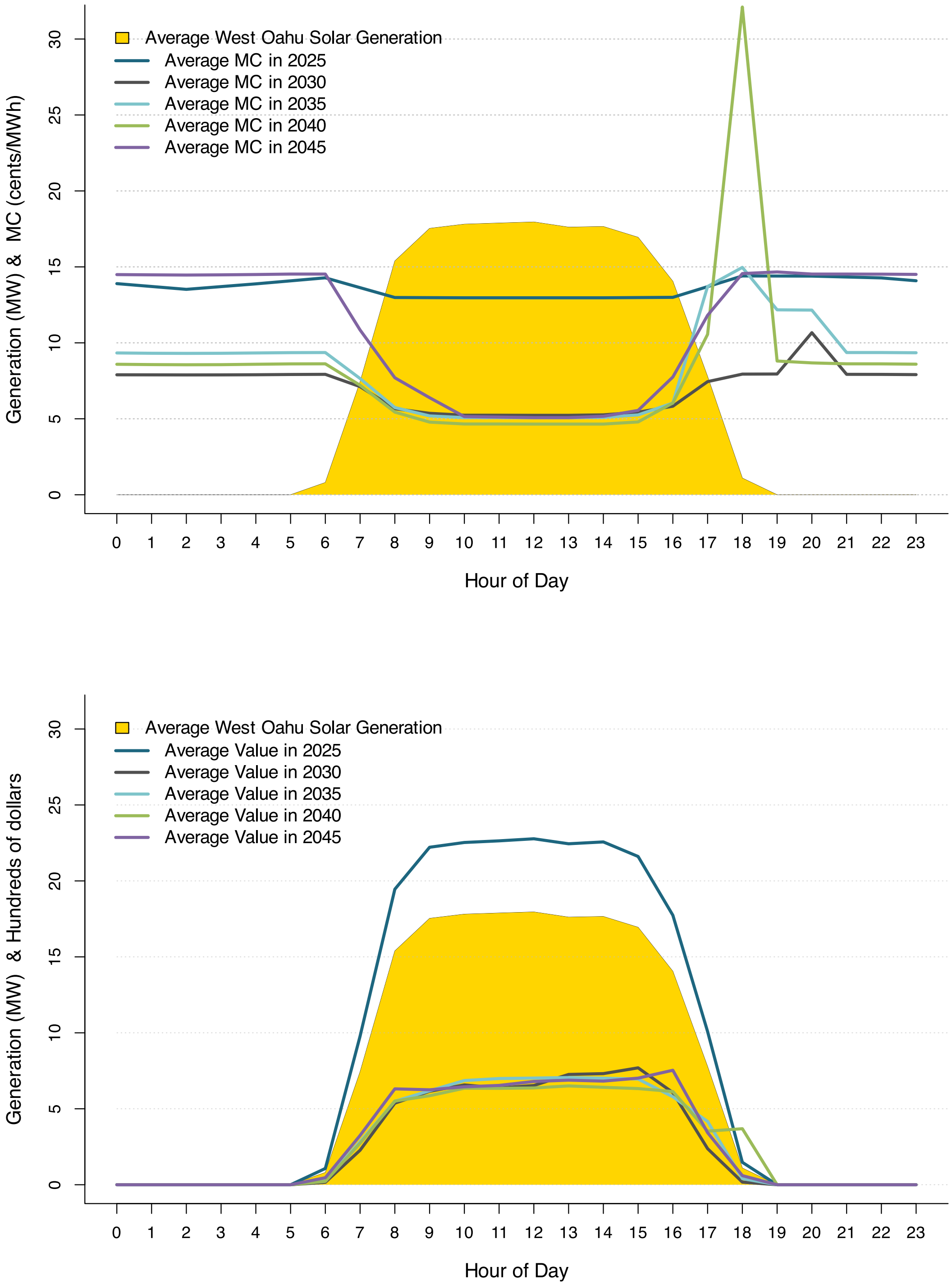
The top panel shows UH Mānoa demand in 2018 and 2020, a low-demand year due to COVID-19. The bottom two panels show how the choice of a CBL affects bills when demand increases or decreases. The left panel shows RTP bills for 2018 when 2018 or 2020 serves as the CBL; the right panel shows RTP bills for 2020 under both CBLs. We simplify billing slightly relative to actual history by assuming a standard DS tariff with a $0.20 per-kWh charge and a $23/kW demand charge applied to the average of each month's peak demand and the annual peak demand. Deviations from the CBL are priced at marginal cost, as observed in 2018 and 2020.

Figure 9. Projected Mānoa campus bills and implications for other customers with projected on-campus investments, current DS tariff, and the proposed RTP tariff with discounted CBL.



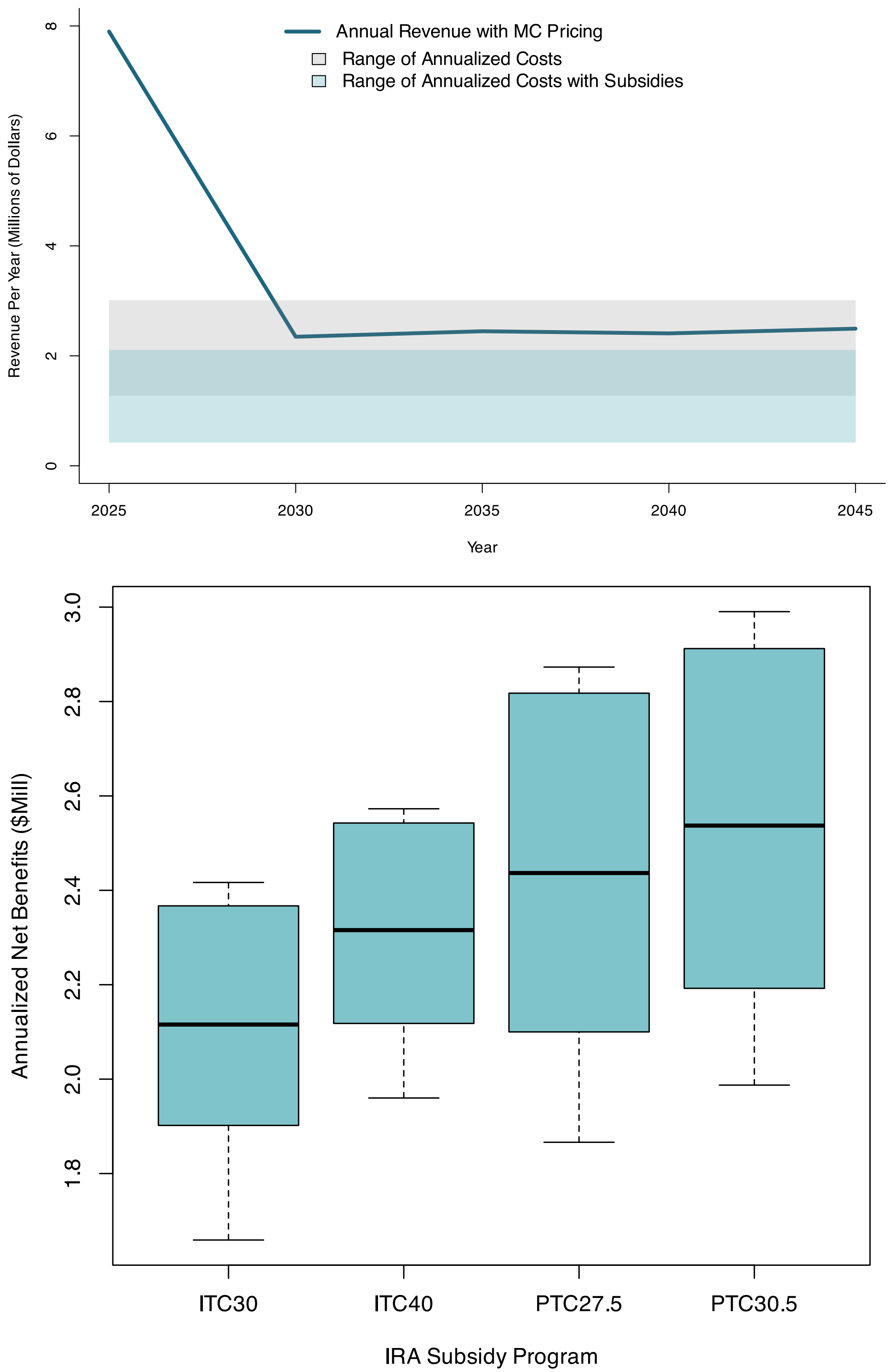
The from left to right, the bars show (1) annual bills under hypothetical status-quo demand without any change in on-campus demand from the baseline year under projected DS tariffs; (2) bills under the projected DS tariffs with planned Mānoa campus installations of solar and battery that will reduce overall demand and peak demand; (3) Hawaiian Electric Company's avoided costs from serving the Mānoa campus given reduced demand in 2; (4) losses to other customers under revenue decoupling, which allows Hawaiian Electric to raise rates to collect lost revenue from UH Mānoa not realized from the avoided cost of serving their reduced demand; (5) bills under the proposed RTP tariff without on-campus solar and battery and a CBL based on 95% of baseline demand in 2025 and a one percentage point lower CBL each year out to 2045; (6) nominal losses to other customers due to the reduced CBL if only the UH Mānoa campus converts to an RTP tariff and there are no additional adjustments to tariffs or demand island wide. Projected future DS tariffs and marginal-cost prices are based on an optimized decarbonization pathway derived using Switch-Hawaii (Fripp, 2020), with updated fuel cost projections.

Figure 10. Generation and value from 25 MW utility-scale solar PV installation in West Oahu.



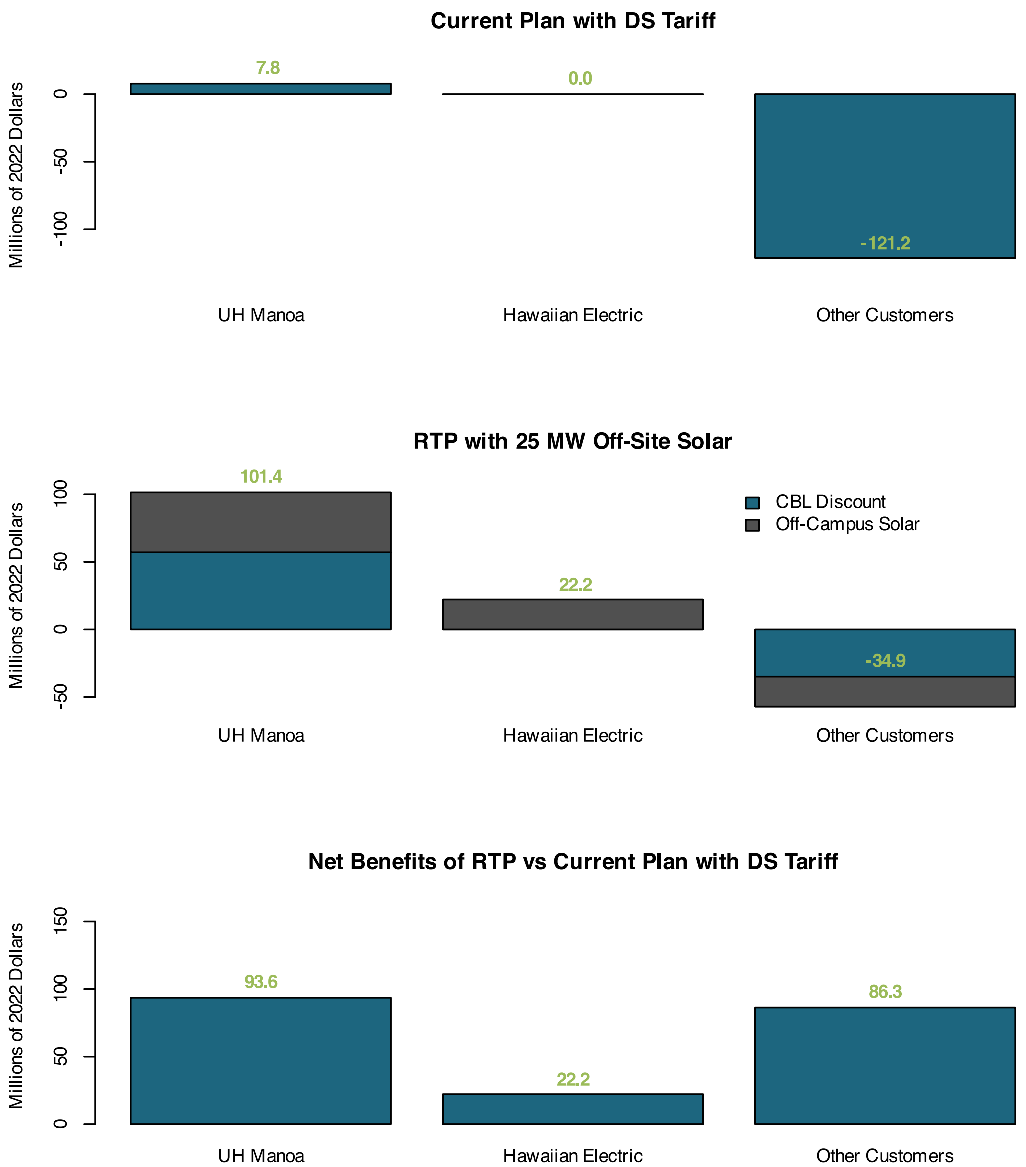
The top panel shows average generation by hour of day from a 25 MW solar PV installation in West Oahu overlaid by the average projected marginal cost by hour of day in each planning year. Marginal cost varies across days more than between hours of the day, so the middle panel shows average revenue per hour considering the relationship between marginal cost and generation across all hours of the year. The bottom panel shows a West Oahu site's annualized revenue and annualized costs. Note that values exclude subsidies that are likely available from the Inflation Reduction Act.

Figure 11. Annualized benefits and costs of a West Oahu 25 MW solar PV installation.



The top panel shows annualized benefits and costs from a 25 MW solar PV installation in West Oahu for each of the five planning years. Interpolating annual benefits between planning years, the bottom panel shows annualized net benefits for the project's life using a range of cost assumptions. Each box and whisker shows the range of net benefits over a range of assumptions under the subsidy program indicated, an investment tax credit (ITC) of 30 or 40% or a production tax credit of $27.5 or $30.5 per MWh.

Figure 12. Overall net present value of benefits of RTP to different stakeholders



These graphs summarize the overall projected impacts of the current UH Mānoa plan (millions of $2022), the proposed RTP, and the net gains to all stakeholders by adopting RTP. Values are in net present value terms, assuming a real discount rate of 2 percent. Our assumptions may differ from those of Hawaiian Electric and UH Mānoa facilities planning. These benefits exclude the mutual benefits of UH Mānoa shifting demand in response to real-time marginal cost prices.

Endnotes

1 The specific terms here, 95% and the one percent decline in the CBL each year the customer remains on the tariff, are critical design pieces subject to negotiation. They should be considered placeholders. Ideally, they would be underpinned by additional analysis.

2 What RAP defines as LRMC is not, in fact, LRMC; it is their own alternate definition that has no basis in economics or operations research. While we understand that the PUC has adopted this definition in its rulemaking around advanced metering, creating a new definition of marginal cost does not change the actual incremental cost or economic efficiency, which is unambiguously defined by a price equal to short-run social marginal cost, as conventionally understood. The idea of using LRMC for pricing originates from Boiteux (1960) and Turvey (1968a, 1968b), among others, and pertains to "peak load" pricing before real-time measurement of electricity use was feasible. See also the relatively recent review by Joskow (2007). Anderson and Bohman (1985) directly address these issues and explain why SRMC is the appropriate guidance, clarifying the confusion surrounding LRMC versus SRMC. It is important to note that SRMC should include scarcity rents and the value of unserved load in the event of rolling blackouts, which will always pose a risk. Although the literature on electricity supply and demand does not typically address storage—aside from hydroelectricity, as this was not commonly available until recently—these issues are addressed more generally by Williams and Wright (1991), Deaton and Laroque (1992), Schenkman and Schectman (1983), and Dixit and Pindyck (1994), among others.

3 Jim Lazar of RAP comments on the cited blog post by Severin Borenstein, and Borenstein also responds to his comments and those of others.

UHERO

THE ECONOMIC RESEARCH ORGANIZATION
AT THE UNIVERSITY OF HAWAI'I

UHERO THANKS THE FOLLOWING SUPPORTERS:

KA WĒKIU - THE TOPMOST SUMMIT

Bank of Hawaii
DGM Group
First Hawaiian Bank
Hawaii Business Roundtable
Hawaii Community Foundation
HMSA
Kamehameha Schools
Queen's Health Systems

KILOHANA - A LOOKOUT, HIGH POINT

American Savings Bank
Benjamin Godsey
Castle Foundation
Central Pacific Bank
D.R. Horton
First Insurance Company of Hawaii, Ltd.
Hawaii Pacific Health
Hawaiian Airlines
Hawaiian Electric Industries
Matson
Tradewind Group

KUAHIWI - A HIGH HILL, MOUNTAIN

Alexander & Baldwin
Better Homes and Gardens Real Estate Advantage Realty
Castle & Cooke Hawaii
Chamber of Commerce
Halekulani Corporation
Hawaii Gas
Hawaii Hotel Alliance
Hawaii State AFL-CIO
Hawaiian Dredging Construction Company
HGEA
Honolulu Board of Realtors
Honolulu Board of Water Supply
The Howard Hughes Corporation
HPM Building Supply
Kaiser Permanente Hawaii
Kyo-ya Hotels & Resots, LP
Nordic PCL Construction
Servco Pacific, Inc.
Stanford Carr Development

ADDITIONAL SUPPORTERS

Architects Hawaii, Ltd.
Charles Wathen Company (Pier Investments)
Chartwell Financial Advisory
Finance Factors
Hau'oli Mau Loa Foundation
The Hawaii Laborers & Employers Cooperation
and Education Trust Fund
Hawaii Tourism Authority
HC&D, LLC
The Natural Energy Laboratory of Hawaii Authority
Pacific Cost Engineering
The Pacific Resource Partnership
Trinity Investments

Kūlia i ka nuʻu (literally "Strive for the summit") is the value of achievement, those who pursue personal excellence. This was the motto of Hawaii's Queen Kapiolani. Supporters help UHERO to continually reach for excellence as the premier organization dedicated to rigorous, independent economic and policy research on issues that are both central to Hawaiʻi and globally relevant.

Over its more than twenty year history, UHERO research has informed decision making on some of the most important issues facing our community, including the ever-changing economic outlook, challenges to our environment, and policies affecting water, housing, energy, and many other areas.

Contributions from generous supporters like you make it possible for UHERO to fulfill this mission. Your financial commitment also allows us to distribute UHERO forecast reports to all Hawaii stakeholders.