UHERO
THE ECONOMIC RESEARCH ORGANIZATION
AT THE UNIVERSITY OF HAWAIʻI

UHERO REPORT

Implications of a "Green Tariff" for the University of Hawaiʻi, Hawaiian Electric Company, and other Customers

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EXECUTIVE SUMMARY

In June 2015 the State passed a law setting a goal for the University of Hawai'i (UH) to produce as much renewable energy as the total energy it consumes; that is, to become net-zero. The great bulk of the University's energy use occurs on the Mānoa campus, which has the most students and by far the most energy-intensive research labs. The scale of electricity use at Mānoa, which averages about 12 megawatts an hour, is unlikely to be met by on-campus renewable generation. As a result, the University is looking for ways to use land resources in an off-site location to generate renewable energy that can compensate for required energy use on the Mānoa campus.

At the same time, the University is looking for ways to reduce its high energy bills, which average over two million dollars per month. Options for self-generation, improvements in energy efficiency, and strategic investment in batteries to reduce its peak load and associated demand charges have been employed to save money, improve efficiency, and reduce emissions.

These decisions also have implications for Hawaiian Electric Company (HECO) and its other customers. To the extent that the University's reduced purchases of electricity from HECO are not offset by lower costs, the University's savings will push costs onto other customers. This possible transference of costs to other customers, rather than to the bottom line of HECO's shareholders, results from the way electricity is priced and regulated. In particular, a revenue decoupling rule that allows the utility to recover a certain amount of revenue regardless of how much electricity HECO actually sells implies that any reduction in revenue from the University of Hawai'i that is not offset by explicit cost reduction will cause prices to increase for everyone else.

To help address the shared interests of the University and HECO, HECO has proposed a "Green Tariff" (officially proposed as "Rider Z") that would, in effect, allow the Mānoa campus to receive credit for solar installed at one of its off-site properties. Under this tariff, HECO would obtain a purchase power agreement (PPA) for solar to be installed on its land elsewhere on the island. For analysis in this report, we consider a parcel in West Oahu, but Rider Z could pertain to any off-site installation. The cost of the PPA would be added to the Mānoa campus bill, and the University would receive a credit for energy provided by the solar installation. If the off-site solar installation and associated PPA were to include batteries, making the site dispatchable like a traditional power plant, then the University would receive additional credit under a "Virtual Rider M" that would act to reduce demand charges associated with the Mānoa campus peak load.

This report considers the implications of the proposed Rider Z on the University's energy costs as well as its implications for HECO and its other customers. The impacts of this tariff depend on other decisions the University makes in managing its energy use over the coming decades, as well as on highly uncertain factors that are outside the control of the University. Most significantly, the value of Rider Z to the University, as well as its impact on other customers, depends on the path of future oil prices and how quickly HECO transitions away from fossil fuels. These factors matter because, under Rider Z, the credit provided to the University for off-site solar is tied to island-wide fuel costs as a share of total generation costs. Thus, the higher are oil prices, and the more slowly the island transitions from fossil fuels, the greater the credit to University.

An overarching concern with the structure of the Rider Z credit is that it is not tied to HECO's avoided costs. Thus, the credit provided for the solar installation may exceed or fall short of its broader value to the system. Similarly, we find that the credit associated with the Virtual Rider M would generally exceed the value of the battery to HECO. On balance, we find that nearly all of the scenarios where the University would save money relative to the status quo imply an even larger indirect cost to other customers. In a typical mid-line scenario, we find that for every dollar the University saves with Rider Z and Virtual Rider M, other customers will collectively pay about $1.14 more.

We consider how a range of additional on-campus investments by the university could change its energy costs, both with and without an off-campus solar installation associated with Rider Z. Under current pricing structures, the University is incentivized to install as much solar as possible on campus, as well as batteries or other devices to flatten its demand profile and thereby reduce its peak demand, which tends to occur midday, coinciding with peak solar production. Given the high assumed cost of on-campus solar installations, solar tends to save more if installed later. While this flattening is costly to the university, it is unlikely to reduce HECO's costs, since midday loads are becoming less costly to serve amid ample supply from growing solar production; thus, while these investments would save the University money, they would shift more costs onto other customers than the University would save. In a typical mid-line scenario, we find that for every dollar the University saves with on-campus investments, other customers will pay $1.15 more.

In addition to using batteries in conjunction with on-campus solar to shave its peak, the University can save even more in the near term by installing batteries to reduce its evening load (coincident with the island-wide system peak) using the existing Rider M. The net savings would again serve mainly as a cost transference to other customers.

In the end, we recommend that Rider Z be revised such that it credits the University (or any other large customer) for solar installations in accordance with the avoided costs to the utility. Tariffs that credit distributed generation according to avoided cost have many precedents. Such a tariff would be simpler and fairer, as it would ensure a reasonable credit to the University and other large customers, even if the rest of the grid were to rapidly transition to renewables and thereby eliminate fuel costs. It would also ensure that other customers would not be negatively impacted by the agreement.

We also recommend that demand charges be reconsidered or eliminated. Most commercial customers with demand charges, like the University of Hawai‘i, tend to have electricity demand that peaks in the early afternoon. Some of these customers, including the University, can and perhaps already have made efforts to reshape their demand to reduce their peaks and/or evening demand. While historically the mid-afternoon peaks were most difficult to serve, today they are among the cheapest loads to serve. Thus, these investments in peak shaving are not only wasteful; they actually increase costs to the island-wide electricity system, and thus can be especially hurtful to other customers via the revenue decoupling rule. Rider Z and Virtual Rider M would make unraveling of these perverse incentives considerably more difficult and thereby complicate anticipated future regulatory efforts associated with Hawai’i’s renewable energy transition.

SUMMARY OF KEY FINDINGS

- Historically, electricity costs were comprised mostly of fuel, which on Oahu, is mainly low sulfur fuel oil. These costs are indicated by the Energy Cost Recovery Factor (ECRF) on electricity bills, and are adjusted each month based on the cost of fuel that HECO and independent generators hold in inventory. As a result, historical electricity prices generally track world oil prices, with a two- to four-month lag.

- For this report, we characterize most other costs as "non-fuel" or "non-energy" costs. These costs include operations, management, maintenance, generation equipment, the grid of wires, and renewable energy, the costs of which generally do not vary with the amount of electricity generated and sold. While these costs were a small share of costs in the past, they are rising rapidly and will continue to do so in the coming years. This sharp departure from the past is happening in part because HECOs sales are declining, causing these fixed costs to be spread over fewer kilowatt-hours sold, and in part because HECO's recent power plant and grid upgrades and ongoing purchases of renewable energy have zero fuel costs.

- Under status-quo energy use and assuming no further on-campus investments in energy efficiency or solar, and a midline projection for oil prices consistent with current market futures prices, we project that the University's electricity bills will be somewhat lower than recent history due to recent declines oil prices, and gradually trend up, mainly due to HECO's rising non-fuel costs that will be spread over a gradually declining system-wide demand. Under this status-quo projection, we assume that Oahu will transition toward renewables at a pace that accords with their Power Supply and Improvement Plan (PSIP). We consider how low, and high paths of future oil prices affect this projection.

- We also assess HECO's costs using a system-wide planning model "Switch 2.0" developed by Matthias Fripp. This model develops a least-cost plan for an island-wide renewable energy transition. Because renewable energy today is considerably less expensive than conventional generation, at least until we achieve very high levels of renewable energy penetration, this alternative account of costs is lower than the PSIP projection, and has especially lower fuel costs, due to the faster renewable energy transition. As a result, under this scenario, the University will receive less credit with Rider Z.

- Another uncertainty with regard to future energy bills for the University concerns the degree to which other customers choose to self generate as solar PV, batteries, and other options become increasingly competitive with HECO's prices. It may be possible for the University to save considerably more by self-generating with solar PV, batteries, and its own co-generation power plant, and possibly other technologies. If it is economic for the University to self-generate, it is reasonable to expect other customers can economically self-generate, too. As a result, HECO's sales may fall further than currently projected, causing non-energy costs per kilowatt-hour and the associated non-energy charges to rise faster. To contemplate such a possibility, we consider a demand projection that is 30 percent less than the baseline PSIP projection for demand.

- On-campus renewable energy investment plans – currently around 17 MW of solar PV by 2035, plus co-optimized batteries to reduce demand charges – might provide significant savings to the university. These savings are substantial even though the University is paying a remarkably high price of 17 cents per kWh for the first 5 MW of on-campus solar. As distributed solar costs fall, the University is looking for ways to increase on-campus solar capacity. Much of these savings, however, will represent cost transference to other customers. Some of the benefits from on-campus solar and co-optimized batteries include reduced demand charges stemming from a lower net-peak.

- The impact of Rider Z on the Mānoa campus electricity bills is limited because the credits only eliminate ECRF, which will comprise a shrinking part of the bill. If the renewable energy transition happens faster than HECO projects, if substantial grid defection occurs, and oil prices stay low, the University is likely to pay more than they would with status-quo pricing from HECO. Adding a Virtual Rider M for a battery associated with the remote solar install, however, greatly improves the value of Rider Z, making the Rider Z generally worthwhile to the University. This benefit, however, comes at a cost to other HECO customers, since HECO could buy a similar-sized battery for far less than the equivalent credit offered by the Virtual Rider M.

- The present value of batteries under Rider M, which under option B-1 currently compensates evening peak load reduction (5-9 pm) at $17.25 per kW curtailed for customers on the DS schedule tariff, amounts to approximately $627 per kWh of batteries installed. It is even greater (over $700) for schedule P customers. This compensation far exceeds the current cost of batteries of about $330 per kWh, according to the National Renewable Energy Laboratory. The University (and all other schedule DS and schedule P customers) currently face a strong incentive to install batteries and use them to curtail evening loads. These benefits would be in addition to benefits from the reduced peak load from solar and co-optimized batteries. These savings to large-scale customers, however, are likely to be costs passed on to other customers.

An interactive website summarizes results under many scenarios.

1. INTRODUCTION

1.1 BACKGROUND

The University of Hawai’i Mānoa currently spends an estimated eight percent of its operating budget on electricity. The campus services over 23,000 students and faculty, 17 housing buildings, 21 research buildings, 7 sporting venues, 3 libraries, and a state-of-the-art information and technology center. The high cost derives from the University’s aging infrastructure, the year-around need for air conditioning, and the state’s high electricity prices, which are the nation’s highest and range between two to five times prices that are typical in other states. Electricity prices grew unusually fast between the late 1990s to around 2008, when oil prices—the predominant fuel used for electricity generation in Hawai’i—rose rapidly. Over this time frame, monthly electricity bills on the Mānoa campus rose from about $800,000 to well over $2 million. While oil prices and monthly bills fell briefly during the Great Recession in late 2008 and 2009, higher oil prices and monthly electricity bills above $2.5 million returned by 2011 and have mostly remained above $2 million since.

Electricity prices and bills remain high despite oil prices having declined considerably since 2014. To see why electricity prices remain high, it helps to consider the components of the electricity bills, and how those components began to change when electricity prices started to spike in the mid to late 2000s.

Electricity billing is normally divided into two broad components: energy charges and non-energy charges. Energy charges comprise fuel costs plus the cost of power purchased by the utility from independent generators on a per-kWh basis, currently reflected on bills as the Energy Cost Recovery Factor (ECRF). Non-energy charges comprise costs of everything else, including the grid of wires and transformers, operations, and maintenance, plus the utility’s own generating equipment, buildings, and other capital. Non-energy charges can also include capacity payments to independent generators that compensate them for their capital expenses. Unlike energy charges, non-energy charges are associated with costs that do not typically scale with the kilowatt-hours generated and sold. Moreover, these costs tend to rise over time, as the grid expands, is upgraded, and wages rise with the broader economy. So long as the number of kilowatt-hours sold rises at roughly the same rate as total non-energy costs, the per-kilowatt-hour non-energy charges do not change much.

Historically, before the oil price spike, fuel charges comprised the bulk of the electricity bill, while non-energy charges were roughly flat since electricity use grew steadily over time. But as fuel costs rose with oil prices, many customers looked for ways to improve energy efficiency in order to reduce their bills. Many were successful in these efforts, aided by advancing technologies, higher efficiency standards, and subsidies for energy-efficient appliances, like solar water heaters and LED light bulbs. Some customers also installed their own generation equipment, including rooftop solar photovoltaics and gas or diesel generators. As a result, sales by Hawaiian Electric Company have declined precipitously since 2007, a marked departure from earlier decades when electricity sales grew steadily with the overall economy.

Thus, even as total non-energy costs continued to rise at almost 9 percent per year, and even accelerated with new power plant and grid upgrades, sales declined, causing non-energy charges to be spread over fewer kilowatt-hours sold, causing prices to remain high even as oil prices fell in 2015 and 2016.

This trend wherein bills are increasingly composed of non-energy charges is about to accelerate for another reason: the growth of utility-scale solar and wind installations that will gradually replace power from thermal power plants. Solar and wind do not require fuel; costs are essentially fixed and thus revenue will be collected as non-energy charges.

The University is concerned about its high electricity bills that have followed from these changes and would also like to reduce its dependence on fossil fuels. Under recent legislation, the University is required to have a goal of becoming net zero by 2035. To achieve this goal, it must eliminate all direct or indirect use of fossil fuels or produce as much renewable energy as it consumed during the 2014-2015 fiscal year, which was set as a baseline.

1.2 PURPOSE AND SCOPE OF THIS REPORT

This report considers implications of Rider Z and Virtual Rider M, which have been proposed by Hawaiian Electric Company (HECO), including its implications for the University's electricity bills and for HECO's revenues net of costs, and by implication, the effect of the agreement on other HECO customers. The proposed tariff would effectively allow the University of Hawai'i at Mānoa to replace the fuel component of its electricity bill (the ECRF) with solar generated from an off-campus parcel located in Dedicated Renewable Facility. Under the proposed tariff, HECO would elicit competitive offers from solar developers for a *purchased power agreement* (PPA), a per-kilowatt-hour rate of solar power generated from the developed site. HECO would pay the developer, and the University of Hawai'i would pay HECO the cost of the PPA instead of the ECRF. All other components of the bill would mostly remain the same. That is, under this agreement, all non-energy charges associated with energy consumed from the off-site solar facility, would still apply. HECO is further proposing a "Virtual Rider M" that would compensate the university for any battery installation that would likely accompany the off-campus solar installation. This credit would reduce demand charges roughly in accordance with what the current Rider M offers if such a battery were to be installed on campus and used to reduce load during system-peak hours (5 pm - 9 pm).[1]

This report develops projections for future bills under various scenarios about future fuel costs under both the current tariff structure and the proposed Rider Z and Virtual Rider M (VRM). We further estimate how the University could use on-campus, rooftop solar, and batteries to reduce bills under each contracting scenario. Finally, we estimate how each kind of contract would affect HECO’s bottom line, equal to its revenues from UH Mānoa less the incremental cost of serving the University’s net electricity demand. Under current regulatory rules, this bottom line, which we call HECO’s Rent, reflects net impact that would ultimately accrue to other customers.

1 HECO has also proposed an associated Rider W that would offer a smaller incremental demand charge for increases in the University’s midday peak load. Because all optimized plans include efforts to reduce rather than increase peak demand, Rider W has no value to the University and is excluded from further consideration in this report.

2. PAST AND FUTURE UTILITY BILLS

2.1 STRUCTURE OF THE ELECTRICITY BILL

Different customers are charged different rates, with rate structures mainly determined by the amount of electricity the customer uses. As one of HECO's largest customers, the Mānoa campus is currently on a "direct service" or DS tariff. As of early 2020, the components of the bill were as follows:

- Customer charge ($425 per month)
- Demand charge ($23 per kW of peak use, about $410,000 / month
- Volumetric charges $0.175/kWh, about $ 1,752,830 / month) comprised of:
  - Energy Cost Recovery Factor (ECRF, $0.14349 / kWh)
  - Revenue balancing adjustment (RBA, $0.009376 / kWh)
  - Purchased Power Adjustment Clause (PPAC, $0.027054 / kWh)
  - Other (DSM / PBF, currently $0.0080 / kWh)

The ECRF comprises the energy charges that effectively would be replaced by a PPA in Rider Z, while all other charges, collectively referred to as non-energy charges, would remain unchanged under Rider Z.

The Energy Cost Recovery Factor (ECRF, formerly called the Energy Cost Adjustment Clause) accounts for fuel costs and purchased power. The Demand Charge is tied to the University's peak use of electricity (kW, not kWh) over any 15-minute period during the previous month and year. It covers the University's share of some non-fuel charges, such as generation capacity, transmission, and distribution, all of which must be sized to ensure capacity can handle the peak demands of the overall system. These two charges are the largest components of the bill and they are set during rate cases, normally scheduled every three years. The ECRF and RBA adjust between rate cases. The ECRF accounts for changes in fuel prices since the last rate case. Historically, the ECRF closely follows the world price of crude oil, with a two- to four-month lag. The RBA adjustment adjusts non-energy charges, mainly in accordance with changes in total sales: the more customers self-generate or otherwise reduce consumption, the more the RBA adjustment will rise, to keep HECO's revenue net of generation costs on track with what was allowed in the last rate case. The PPAC is a fee to cover HECO's non-fuel charges (such as capacity payments) associated with contracts from independent generators. Other bill components are small and not explicitly considered.

A rate case involves a negotiation between HECO and the Public Utilities Commission (PUC), including feedback from stakeholders and the State's Office of Consumer Advocacy. The rate case resets the RBA to zero, folding the RBA into other non-energy components depending on what the PUC approves.

2.2 HISTORICAL BILLS AND BILLING COMPONENTS

The University's monthly bills and the major components are shown in Figure 2.1. Wide fluctuations in energy charges, driven by world oil prices, are evident. The graph also shows how much non-energy charges (demand charges, the RBA, and PPAC) have risen since 2010. Before 2012, non-energy charges were typically less than 20 percent of the bill, but then rose sharply. By late 2015, after oil prices fell, non-energy charges briefly exceeded energy charges but settled a little above 40 percent in 2017. A recent collapse in oil prices caused the ECRF to all to around 30 percent. However, continued declines in HECO sales and a steady rise in total non-energy costs, plus substantial planned investments in grid infrastructure by HECO, all portend substantial future increases in non-energy charges.

2.3 THE DIFFERENCE BETWEEN ENERGY CHARGES AND MARGINAL COST

The idea of Rider Z is that some of the University's power will come from its off-campus solar installation instead of HECO's normal generation mix. Thus, the purchase power agreement (PPA) for the solar will replace the ECRF. To achieve this end, Rider Z credits the university a monthly amount equal to the contracted energy provided by the off-campus solar installation, while adding the cost of the PPA. Other, non-energy components of the bill mainly stay the same, presumably to cover transmission, distribution, operations, and management. Note that the monthly credit under Rider Z would be for the guaranteed average production from the site, not the actual realized yield of energy; any surplus energy generated above the guaranteed minimum would be forfeited to HECO.

A problem with Rider Z is that generation sources differ. Some generation sources are more flexible than others, and the utility needs to manage the whole mix in a way that ensures stability—a perfect match between supply and demand of power over time—while keeping costs as low as possible. To evaluate how Rider Z will affect HECO's bottom line, we therefore ought to consider how HECO will use the new solar power in the broader generation mix, and which other sources it will displace. The value of the new solar power will equal the energy charge only if the new solar power displaces a gradually declining proportionate share of fuel-based generation, which is unlikely. A better approximation of the value of savings would be to consider the *marginal cost* of power at the times the new solar installation will generate power. In our analysis we estimate the marginal value of solar energy using an optimized plan for the Oahu grid, using open-source software Switch 2.0, in conjunction with synchronized solar irradiance data for one site in West Oahu where a renewable energy facility might be placed. This model has been used in other regulatory proceedings before the Public Utilities Commission, but it is not a model that HECO uses for its own planning. Synchronized solar radiation data come from PV Watts, developed by the National Renewable Energy Laboratory (see: http://pvwatts.nrel.gov/index.php). We similarly consider the cost of serving the UH Mānoa campus, taking the synchronized timing of its demand into consideration.

We can also look at historical marginal costs in relation to electricity bills. Historical marginal costs come from the “system lambda” the HECO reports to the Federal Energy Regulatory Commission each year (data from Form 714, available here).

We compare these alternative measures of fuel costs, averaged over each month, in Figure 3. It is evident that the marginal costs of generation are lower than the ECRF. At first blush, this disparity is somewhat surprising, because generation loads are typically ordered from lowest cost to highest costs, such that marginal costs will normally exceed average generation costs. For example, the lowest-cost generation sources on Oahu derive from the independent power producers, AES and Kalaeloa, which comprise about half the island’s power. These plants are almost always operated at full capacity or near-full capacity and are rarely marginal. Incremental generation—that likely to be displaced in the near term by the new PPA—is usually derived from HECO’s older and less efficient power plants. In other words, one might expect marginal cost to exceed average fuel and purchased power costs reflected in the ECRF, but it does not.

We do not have access to full accounting of this discrepancy, but there are a few factors that may help to explain it. HECO is required to accommodate certain energy costs that are much more expensive, including the H-Power trash-burning facility, renewable energy purchased from earlier, high-cost feed-in tariffs, and other past purchase power agreements. While some of these sources are unusually expensive, they comprise a small share of the generation mix. Another factor is the fact that HECO maintains ample reserves, largely derived from its own power plants operating near minimum generation capacities, which is inefficient. These factors increase average generation costs, even while incremental costs can be lower. Regardless of whether the discrepancy comes from these or other factors, the historical data suggest that HECO’s avoided costs associated with new solar generation facility will be less than their loss of energy charges, at least in the near term. As a result, Rider Z could increase prices to other customers via the revenue decoupling rule.

Another reason why the value of solar generated will differ from lost energy charges concerns the timing of solar generation relative to UH Mānoa’s electricity use. Historically, the average marginal value of midday solar generation exceeded the average marginal cost of electricity used by UH Mānoa (note that in Figure 2.3, the green line lies above the blue line before 2014). More recently, however, as distributed solar generation has reduced net demand during sunny times, the marginal cost of serving midday times has declined. This trend is likely to continue going forward; in California and other places with high penetration of solar, marginal cost has fallen considerably. Thus, while the average value of solar that could have been generated at the off-site facility and that used on campus at UH Mānoa were similar in 2015, as solar generation grows, its value will continue to decline, causing a larger gap between between the ECRF and the savings from the off-site solar installation. This difference will be passed on to other customers.

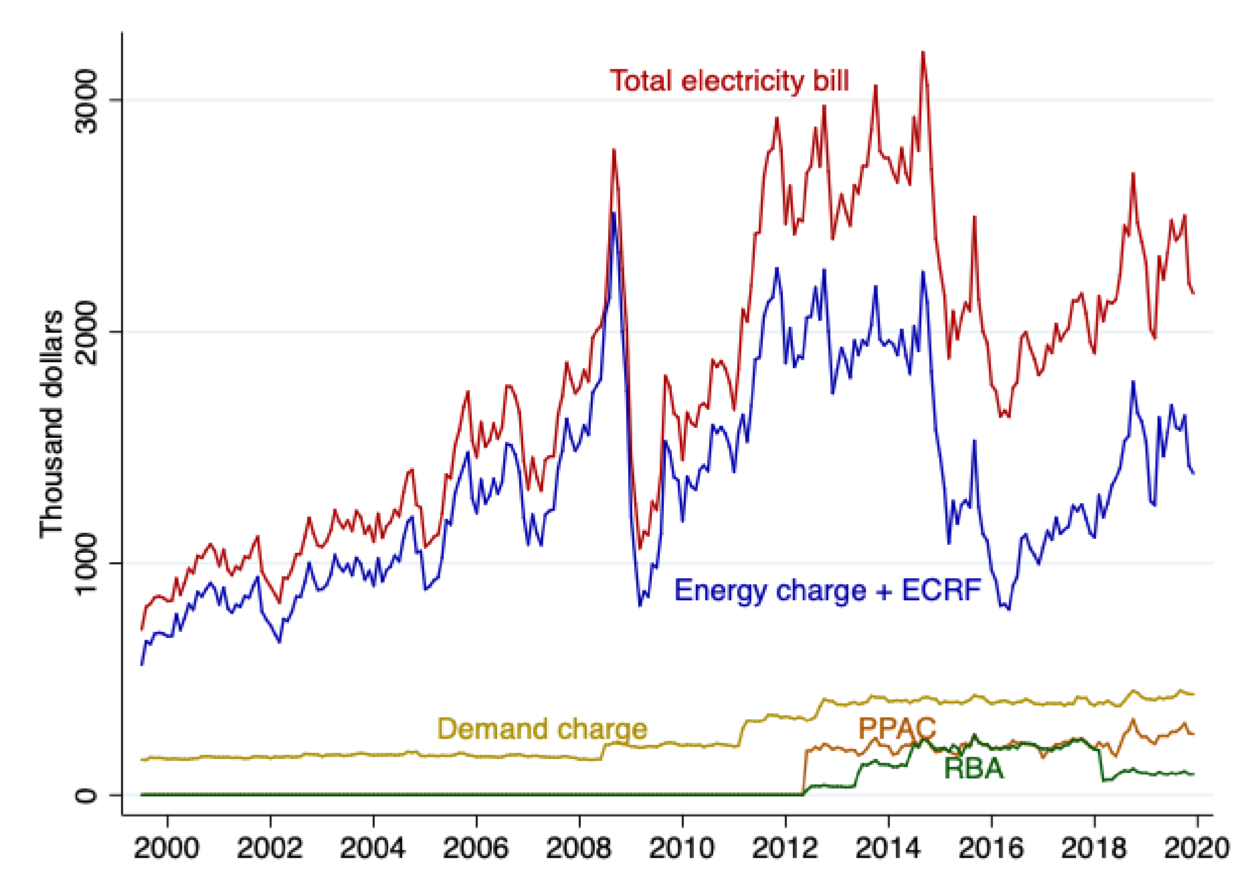

Figure 2.1. Historical UH Mānoa Bills and Major Components.

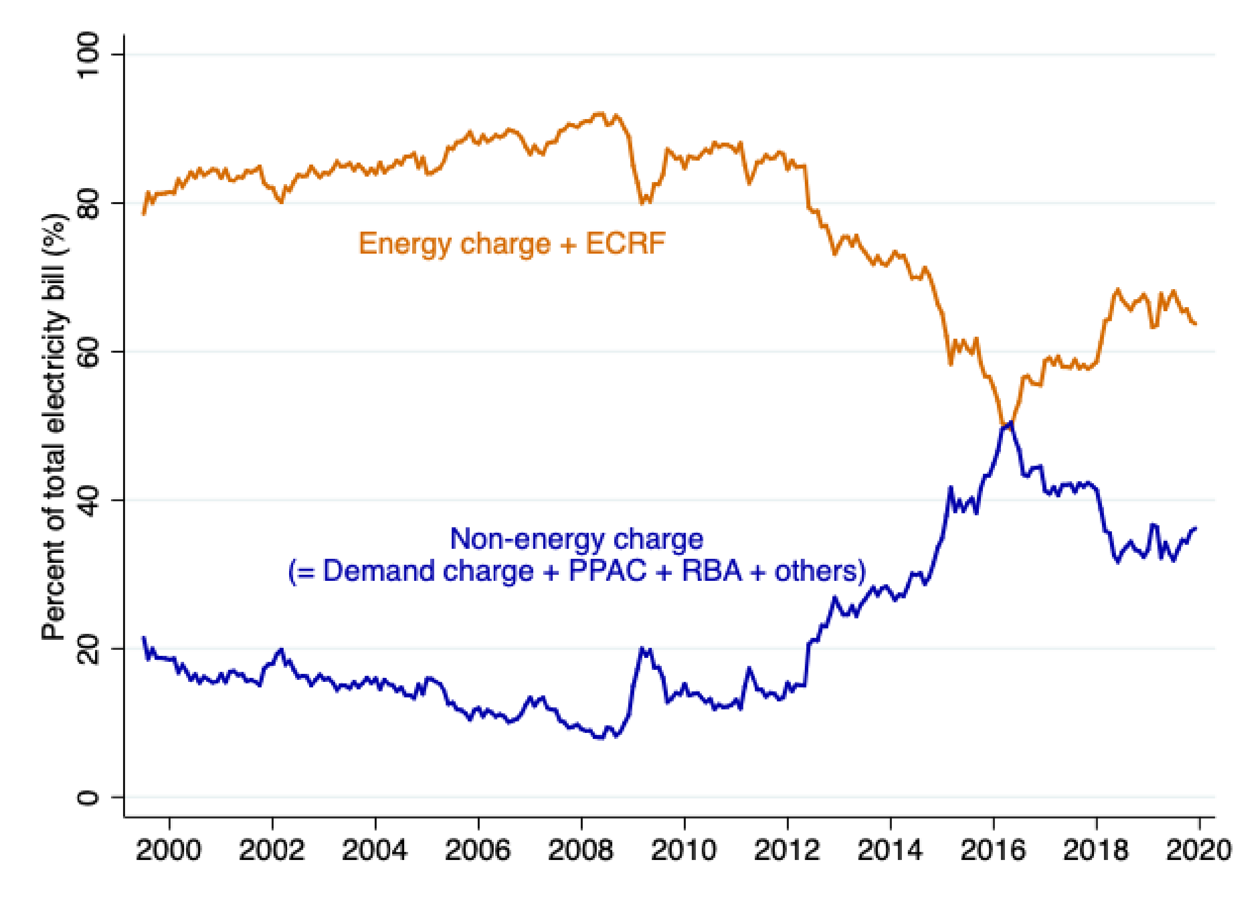

Figure 2.2. Energy and Non-Energy Shares of UH Mānoa Electricity Bills.

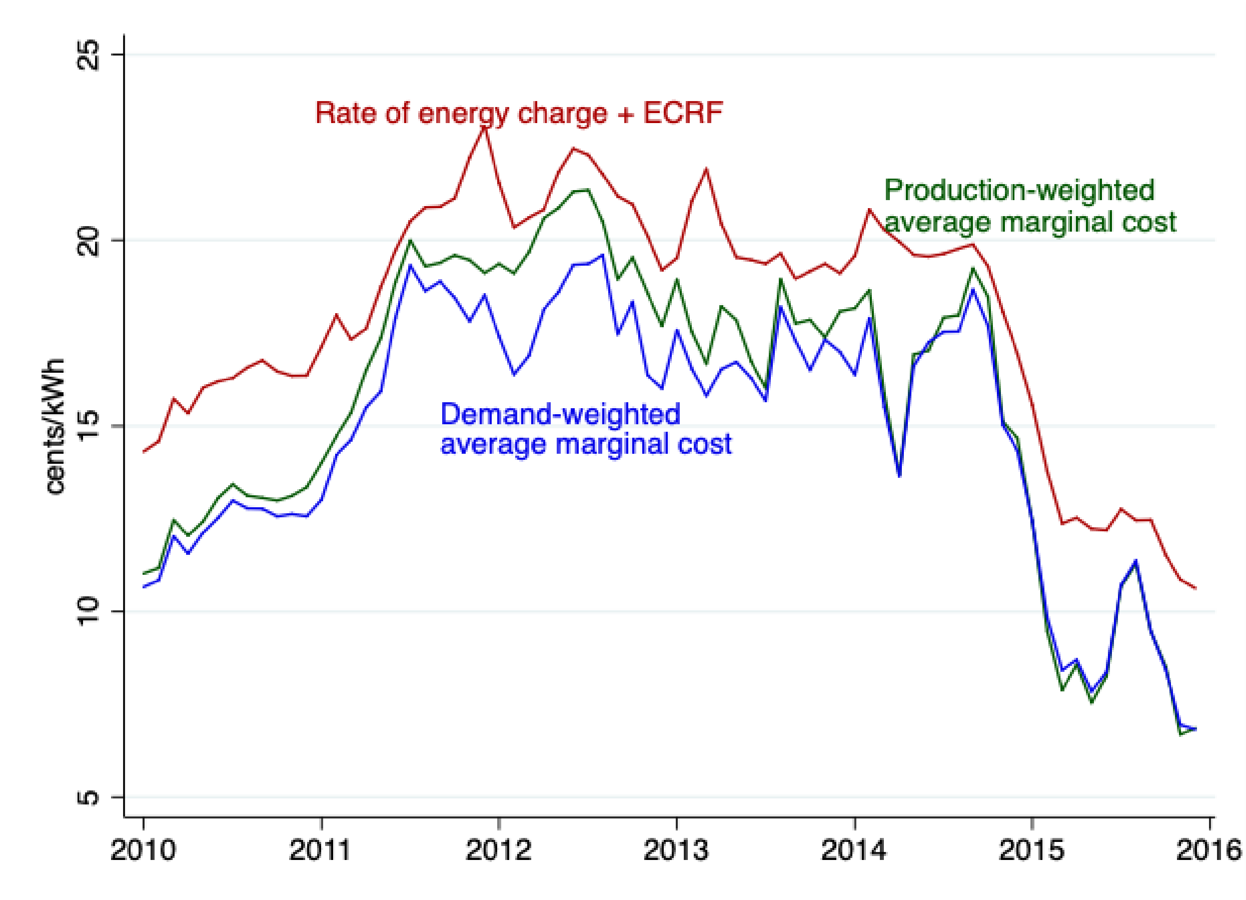

Figure 2.3. Monthly Energy Charges and Marginal Cost of Serving UH Mānoa

Notes: The figure shows the per-kWh rate of energy charge and marginal cost. The energy charge rate sums the base charge and ECRF. Marginal cost is given by the hourly system lambda, obtained from Federal Energy Regulatory Commission (FERC). Marginal cost weighted by using two different variables: 15-min UH Mānoa electricity use (blue) and hypothetical PV generation in (green). The graph ends after 2016 because we did not have real-time (15 minute) interval data for UH Mānoa after this time.

3. PROJECTING FUTURE ENERGY AND NON-ENERGY COSTS AND CHARGES

The ECRF is strongly associated with Brent crude oil prices, with a modest lag in time. HECO’s power plants, which currently comprise about 40 percent of generation and sales, use oil-based fuels. HECO keeps about three months of fuel inventory, and oil prices used in calculation of the ECRF use the average price paid for oil in inventory, which explains the lag. In addition, about 25 percent of generation comes from the independently owned Kalaeloa power plant, which also burns oil-based fuel. Kalaeloa keeps only one month of inventory, so the time lag between world oil prices and this component of the ECRF is shorter. Other power sources have little connection to oil prices. Most prominent among these is the AES power plant which burns coal, a much cheaper fuel (3-4 cents per kWh). Smaller but much more expensive generation components include solar, wind, and power generated from HPower, the trash burning facility on the island.

To forecast how energy charges are likely to change going forward, we developed a statistical model that links each component of the energy charge to Brent crude prices. We then combined these estimates with three different projections for future oil prices, HECO’s projected future fuel mix in the Power Supply and Improvement Plan (PSIP), and projected costs of anticipated future solar installations in the PSIP.

3.1 HISTORICAL LINK BETWEEN ENERGY CHARGES AND OIL PRICES

We estimated the statistical relationship between Brent crude oil prices and the average variable cost of major components in the generation system: (1) power purchased from the AES coal-fired plant; (2) power purchased from the Kalaeloa power plant; (3) HECO’s oil-fired power plants (pooled); and (4) all other sources of power (pooled). Each component was linked to its own historical lag structure of oil prices; this link is very strong for the oil-fired power plants and relatively weak for the other components. The non-oil cost components are more stable.

The historical relationship between our oil-based estimate of energy charges and actual energy charges is shown in Figure 4. More details on these estimates can be found in this earlier paper by Karl Jandoc and Michael Roberts.

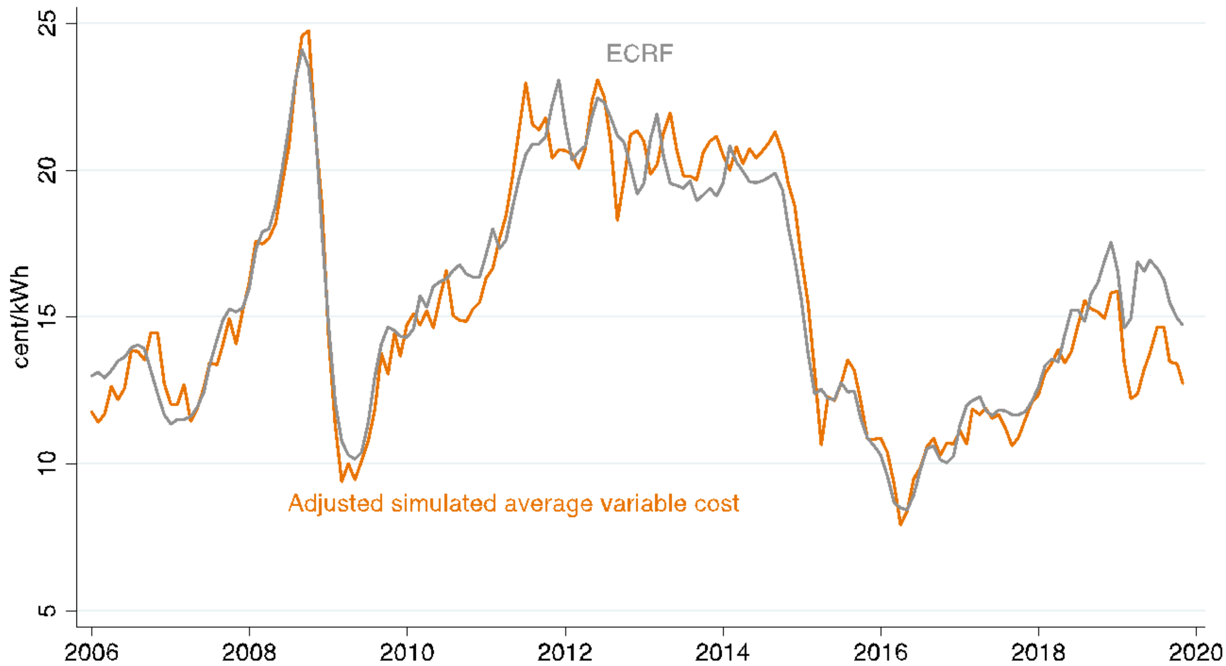

Figure 3.1. Actual and Simulated Energy Charges

Notes: The grey line shows HECO's actual energy charge (ECRF). The orange line shows the simulated energy charge that links each major generation component to world oil prices. This simulation model is used to project futures energy charges given a projection for future oil prices.

3.2 FUTURE OIL PRICE SCENARIOS

We consider three future oil price scenarios, plotted in Figure 5.

- *High*: A forecast based on the Department of Energy's Energy Information Administration (EIA) and similar to HECO's forecast. Historically, EIA forecasts tend to be high.
- *Moderate*: A forecast based on futures markets that extend about eight years into the future, coupled with an assumption that oil price rises at the rate of inflation after the last futures contract. We regard this forecast as the best moderate forecast. The projections in this report are based on futures prices on May 5, 2020.
- *Low*: A forecast based on futures markets and the implied volatility of oil prices based on market option prices on May 5, 2020. This low forecast considers one standard deviation of implied volatility below the futures price. We regard this low forecast as highly plausible, but lower than expected.

All three scenarios for future oil prices should be interpreted as reasonable expectations for the future. While the difference between the high and low scenarios is wide, it understates the range of what is possible. Currently there appears to be ample supply of global oil reserves, which have grown due to innovations in oil extraction, especially hydraulic fracturing or "fracking," as well as reduced demand following onset of the COVID-19 pandemic. In the near term, however, there is considerable political uncertainty around production and trade in the Middle East, Russia, and other countries, as well as demand uncertainty stemming from COVID-19. Over the longer run there is considerable uncertainty about demand for oil, due to the uncertain growth of electric vehicles, shipping, and airline travel. Uncertainty about oil prices today differs markedly from that a decade ago when there appeared to be a fundamental limit to economically recoverable reserves. In our view, and in the apparent view from markets, EIA's oil price projection is quite high, which is why we use it for this scenario.

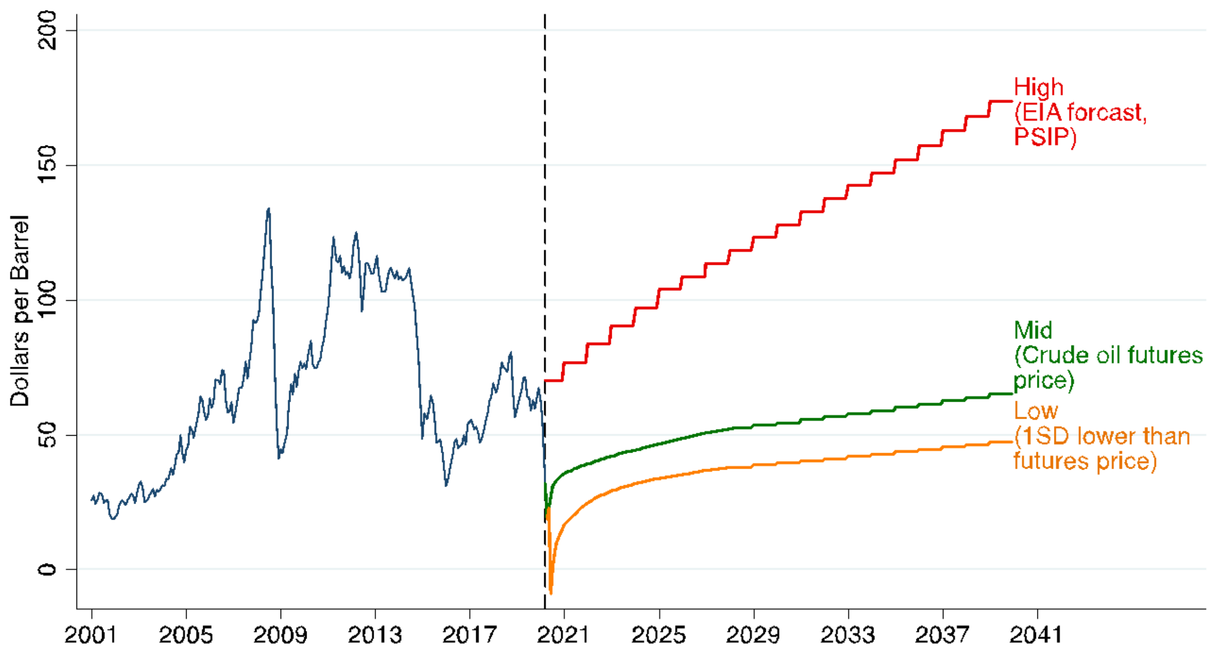

Figure 3.2. Three Plausible Scenarios for Future Oil Prices

Notes: The High scenario denotes the future Brent crude oil prices projected by Energy Information Administration (EIA) in the Annual Energy Outlook 2017. Since EIA forecasts prices only for 2025, 2030, 2035 and 2040, the prices of other years are computed using linear interpolation. The Mid scenario is based on the Brent crude oil futures prices. The Low scenario is one-standard deviation lower than the crude oil futures prices, calculated using the implied volatility of futures prices. Since the future price contracts end in 2024, the prices after 2024 are assumed to increase at the assumed 2 percent inflation rate. The Brent crude oil futures prices and implied volatilities are collected from barchart.com on May 5, 2020.

3.3 FUTURE ENERGY CHARGES

We analyze the statistical links between historic oil prices and energy charges (base + ECRF) to predict future energy charges that accord with each future oil price scenario. The generation mix and kilowatt hours from each source are assumed to follow HECO's PSIP K-3 scenario, which we replicate below in Figure 6. Projections assume that coal generation power from AES is phased out as projected in the PSIP, replaced by a combination of oil and utility-scale solar. Note, however, that future solar purchases will have no fuel costs, and purchases will pertain to capacity rather than kilowatt hours generated. As a result, we assume costs of future utility-scale solar will accrue to non-energy charges. These non-energy charges are added to baseline growth in non-energy charges described in the next section.[2]

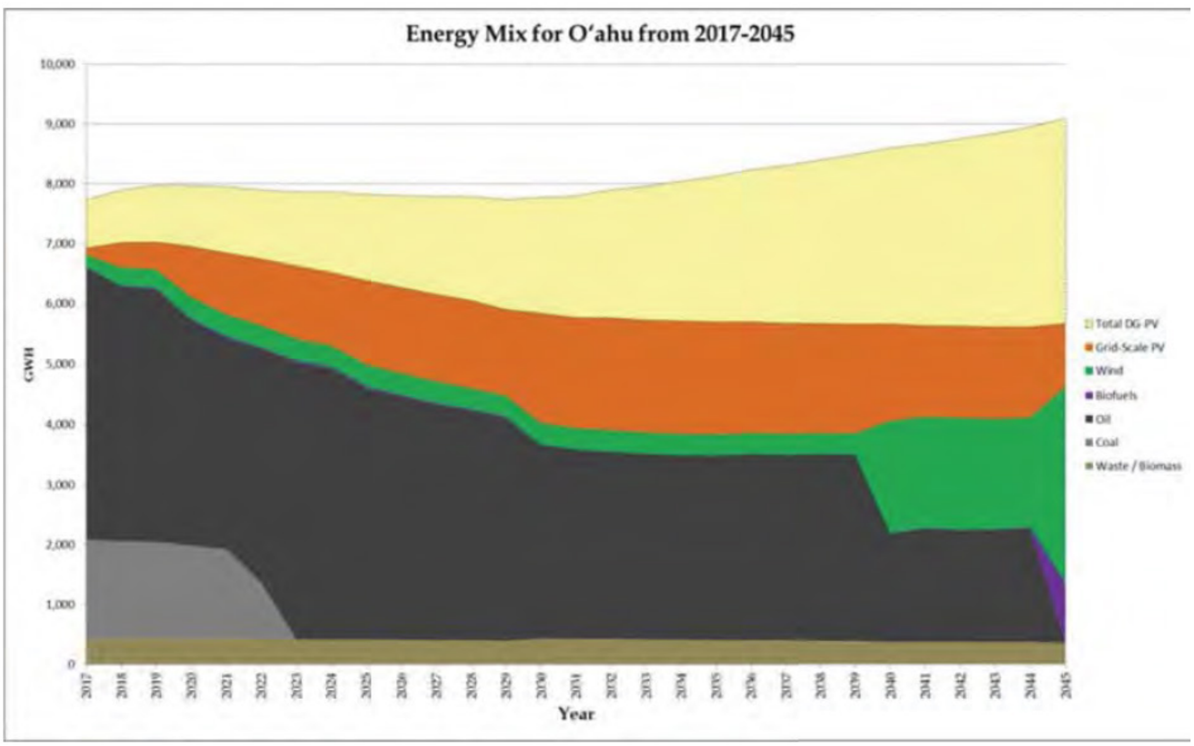

Figure K-3. Energy Mix for Post-April PSIP Plan on O'ahu

Figure 3.3. Projected Generation Mix from HECO's Power Supply and Improvement Plan, 2017-2045.

Notes: This figure is copied from Hawaiian Electric Company's PSIP, December 2016. Net generation (ie., HECO's sales) excludes distributed generation, indicated in yellow on the graph. Light grey indicates coal generation from AES which is scheduled to phase out by 2023.

2 HECO's PSIP includes alternative plans with more wind, less solar and/or natural gas replacing much of the oil. Projected net load looks the same across all scenarios. We expect our method of projecting costs would look similar under the other plans.

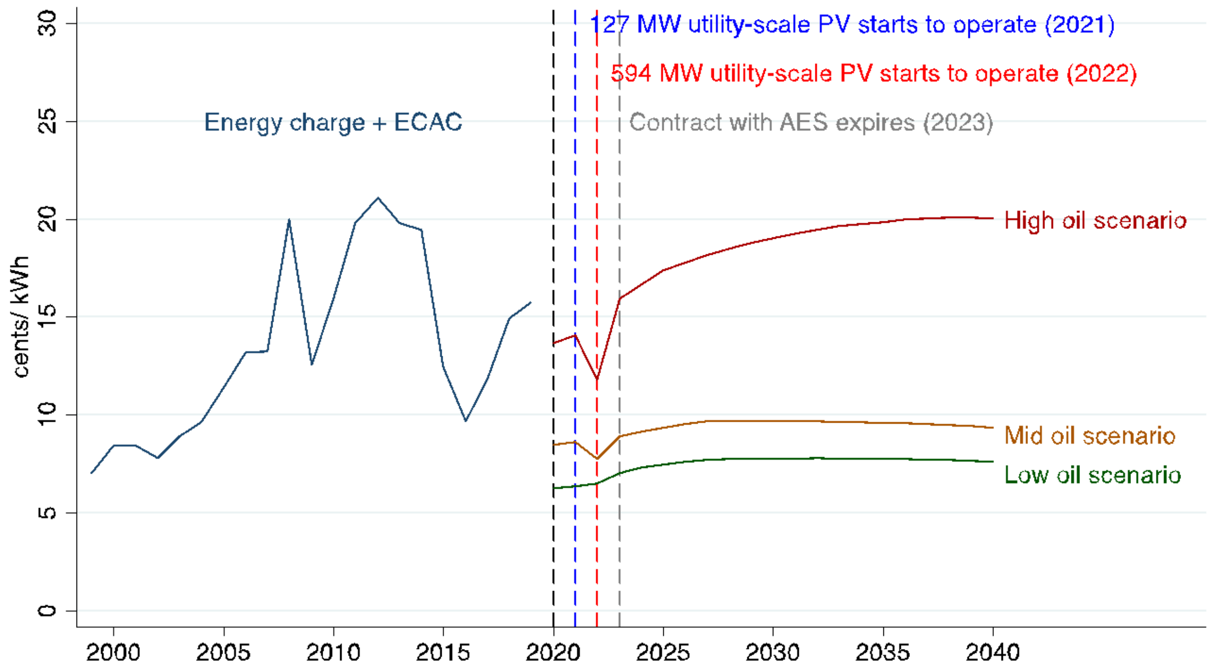

Figure 3.4. Energy Charges Under Pricing Scenarios, 2019-2039

Notes: Projections combine historical links between different generation sources with oil prices and assume future mix of generation that accords with HECO’s Power Supply and Improvement Plan (PSIP) from December 2016 (Figure 6), including projected retirement of AES coal power plant and gradual growth of solar generation with zero fuel costs.

3.4 ESTIMATING FUTURE NON-ENERGY CHARGES

We asked the UH-HECO working group to provide an estimate for how much they project non-energy costs to increase given their planned investment and projected futures sales. The projections they provided did not clearly separate energy (ECRF) and non-energy charges, so we developed our own projection based on the historical trend in total non-energy costs.

This projection was done as follows. We obtained data on total revenue and total kilowatt hours of sales using data reported to the Energy Information Administration. We then calculated total energy charges by multiplying the energy charge by kilowatt hours. Finally, we subtracted total energy charges from total revenue which gives a time series of total non-energy costs. We made these calculations using both actual energy charge and our proxy for energy charges that is based on world oil prices. The results of these calculations are presented in Figure 8, which shows that total non-energy charges have been growing at an average rate of 8.9 percent per year from 2006 to 2017. Going forward, our projections assume non-energy charges will grow at an annual rate of 5 percent, which we regard as conservative given historical growth and planned future upgrades to the grid.

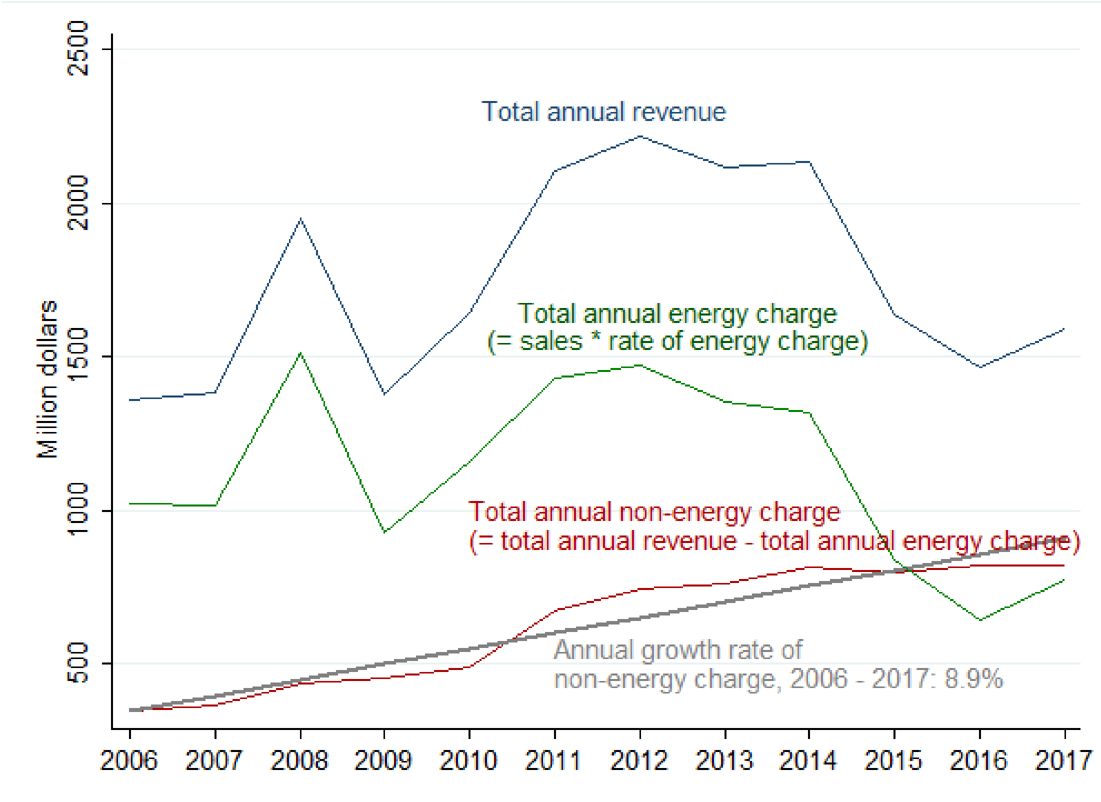

Figure 3.5. Total Revenue, Energy Charges and Non-Energy Charges, 2006-2017.

Notes: Total revenue equals total sales by HECO as reported to the Energy Information Administration. Total non-energy charges are calculated by subtracting total energy charges (Base + ECRF) x (kWh sold) from total revenue. Over the last decade these costs have grown at an average annual rate of 8.9 percent, and will reach nearly $1 billion annually after the recent rate case is included (not shown).

To convert projected future non-energy costs into rate adjustments, we assume that total non-energy charges for DS-schedule customers (like UH Mānoa) grow at the same rate as the aggregate, and that net demand from DS customers changes at the same rate as aggregate net demand. On a per-kilowatt-hour basis, these charges will rise as total energy charges rise and/or total kilowatt hours sold decline, as projected in the PSIP. Given the rapid growth of non-energy charges, plus increasing options by customers for self-generation, we consider scenarios where net demand declines by an additional 30 percent, causing a faster increase in per-kWh non-energy costs. We assign half of the growth in non-energy charges to the per-kWh rate, and half to demand charge (per kW of peak). This allocation of non-energy charges was recommended by the UH-HECO working group. Holding UH electricity demand the same as it has been historically, we project total non-energy charges to the university and plot these in Figure 9.

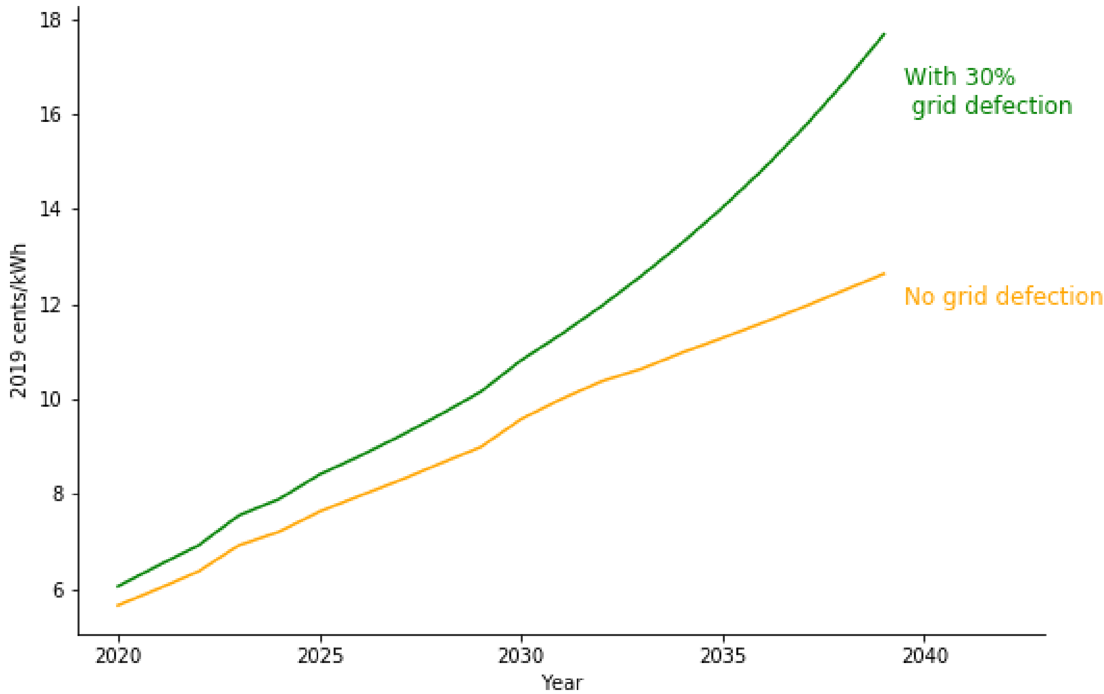

Figure 3.6. Projected Non-Energy Charge Under PSIP and 30% Additional Defection, 2019-2039

Notes: The non-energy charge is currently a combination of demand charge, RBA, PPAC, PV generation costs and other smaller components. We assume that, in the future, HECO will collect 50% of future non-energy costs from the demand charge and 50% from per-kWh PPAC and RBA charges. To see how additional load decline (i.e., grid defection) may affect the UH's non-energy charge, we estimate the non-energy charge with and without an additional 30% decline in net demand relative to PSIP projections. Without additional load decline, future energy sales are assumed to match PSIP projected net load.

4. BASELINE PROJECTIONS FOR UH MĀNOA'S ELECTRICITY BILLS

In this section we report projected UH Mānoa bills under each of the three oil price projections, four electricity demand projections (see Figure 10), PSIP projected net generation and mix, and two systemwide net-load projections. In section 5 we consider how anticipated on-campus solar and battery investments alter the projections presented in this section.

4.1. SCENARIOS CONSIDERED

We consider a range of plausible assumptions such that University administrators, regulators and other stakeholders can obtain a sense of the uncertainty, as well as a sense of how different factors matter for overall overall projections. All combinations of the following sets of assumptions are considered:

- Energy efficiency improvement on the Mānoa campus (4)
    - No change from historical demand
    - 10% reduction relative to history
    - 20% reduction relative to history
    - 30% reduction relative to history
- Oil price path (3)
    - High: projections from the Energy Information Administration (EIA)
    - Middle: based on futures prices for brent crude oil
    - Low: one standard deviation of implied volatility below future prices.
- Systemwide net load (affects non-energy charges) (2)
    - As projected by HECO's Power Supply and Improvement Plan (PSIP)
    - A trend that ends 30 percent below HECO's PSIP

Assumptions underlying the oil price scenarios, system-wide net load and future energy mix in the PSIP were described in the previous section. In addition to these, we consider the implications of reduced electricity demand that may follow from investments in energy efficiency. Energy efficiency improvements, such conversion to LED lighting and new air conditioning systems, may also come about in conjunction with gradual remodelling or redevelopment of many older buildings on campus. Earlier energy audits suggested that efficiency improvements could reduce the University's electricity demand by one third. The University may also expand laboratory and research facilities, which could increase electricity demand.

To simulate how energy efficiency gains would influence electricity bills in conjunction with the Rider Z and other on-campus investments in generation and electricity storage, we considered a range of demand projections from no-change to a 30 percent reduction from recent history (Figure 10). Note that we do not consider the costs of energy efficiency improvements in this report.

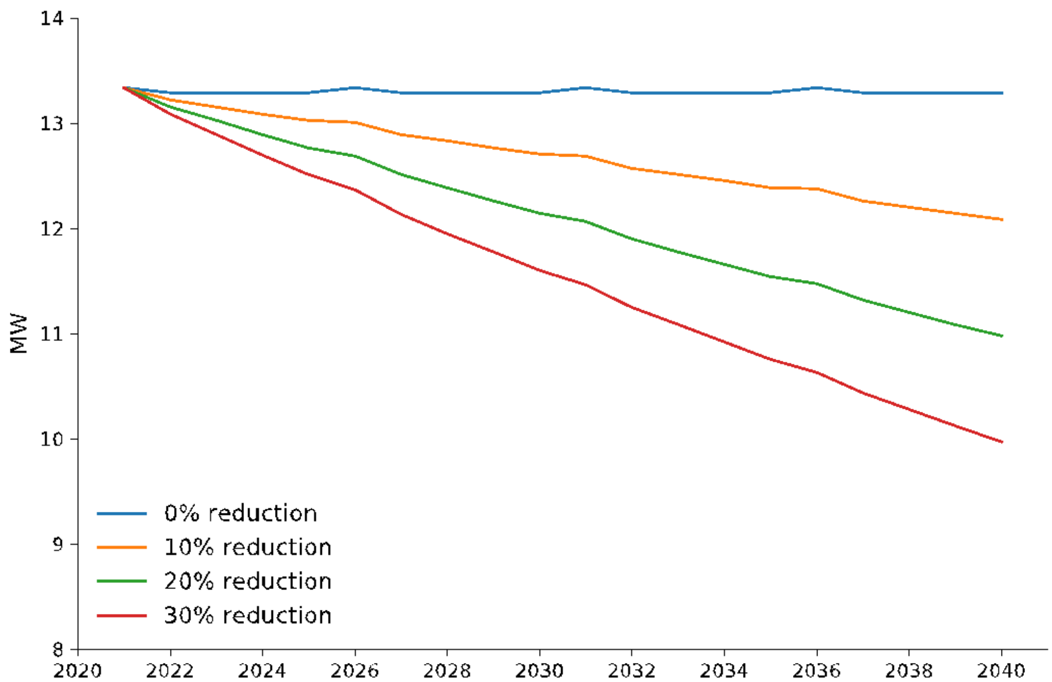

Figure 4.1. Projected Annual Average Electricity Demand of the UH, 2019-2039

Notes: The figure shows UH's annual average electricity demand projection under four different cases. 0% reduction indicates the UH demands electricity at the current level until 2019. 10% reduction describes the case that the UH constantly lowers its electricity demand from 2020 and achieves a 10% demand reduction by 2039. The same explanation is applied for 20% and 30% reduction.

A large share of the savings to the University from energy efficiency investments, just like investments in on-campus generation, would be passed on to other customers, given marginal costs avoided are so much less than University's reduced bill. This problem has been described in many places and appears to be well understood by regulators. It is a problem that is growing more acute in many states, especially those on the East and West coasts of the continental United States (Borenstein and Bushnell, 2019), but is especially problematic in Hawaiʻi. We address this issue more squarely in Sections 8 and 9.

4.3. PROJECTED BILLS

Projected bills for seven of the baseline scenarios are depicted in Figure 9. The status quo, which assumes no investment in energy efficiency or on-campus generation, middle oil price based on futures, and PSIP projected loads, is replicated in all six panels of the figure. This reference reflects a conservative projection under a business-as-usual scenario, providing a benchmark to see how energy efficiency improvements, on-campus solar investments, oil prices, or load defection could affect future bills. We regard this status-quo scenario as conservative because we assume total non-energy costs will increase at a rate of 5 percent per year, which is notably less than recent history (an average of 8.9 percent per year from 2006-2017—see section 3.4 above).

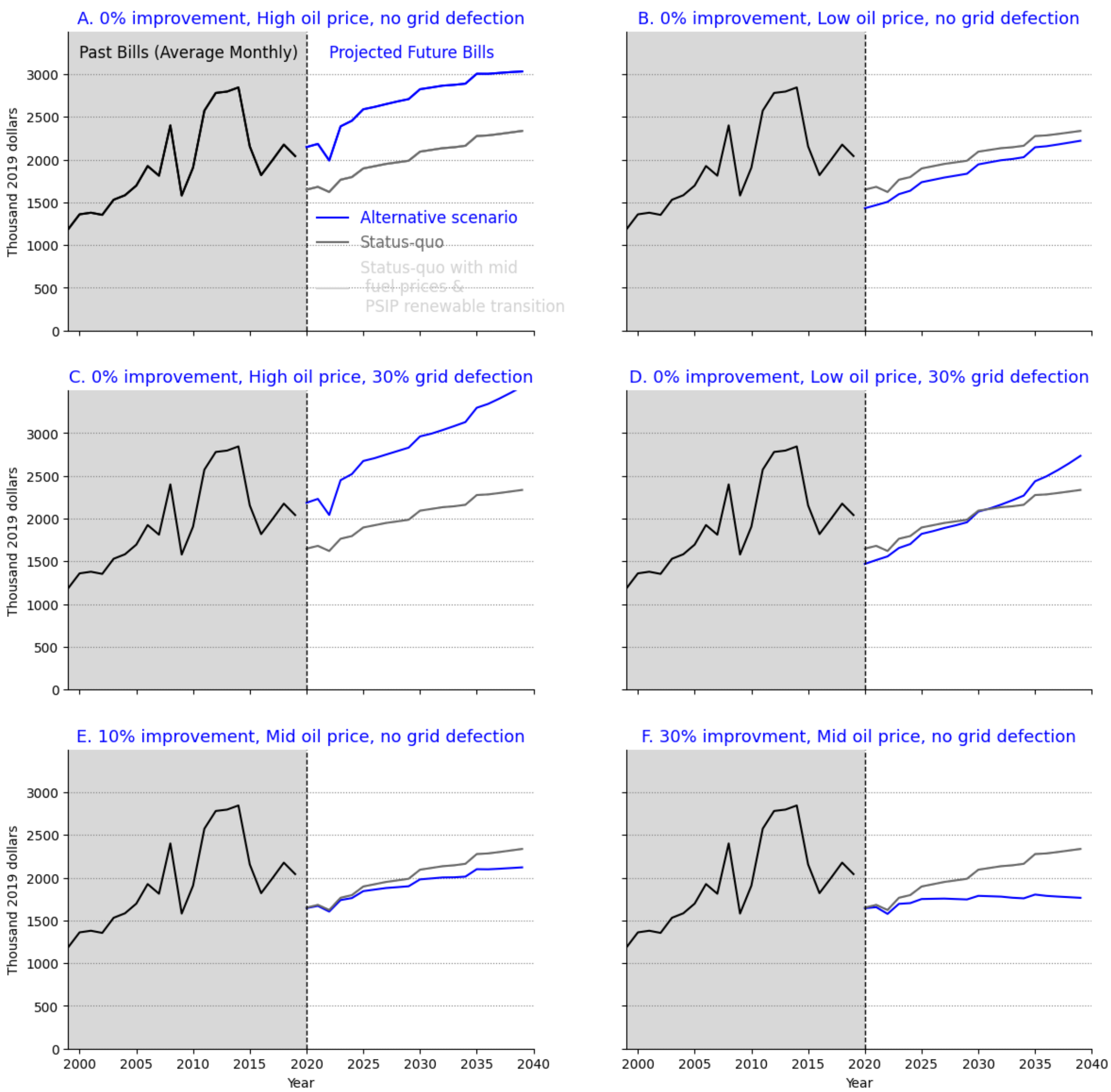

Figure 4.2. Historical and Projected Future Electricity Bills for UH Mānoa Under Various Scenarios, 2020-2039.

Notes: Each panel shows a scenario for future UH Mānoa electricity bills relative to a business-as-usual projection based on the current tariff, oil price futures, and baseline projected energy and non-energy charges. All values are inflation-adjusted (2019 dollars). Panels A and B show high and low projections for oil prices, all else the same. Panels C. and D. show high and low projections for oil prices coupled with 30% extra reduction of electricity sales by 2039 compared to PSIP projection. Panels E. and F. show scenarios with the UH's energy efficiency improvement plan which would reduce 10% and 30% of UH's electricity demand gradually by 2039.

A few conclusions can be discerned from these scenarios:

1. After adjusting for inflation, electricity bills will grow and may exceed record high bills from a few years ago, even if oil prices do not rise from today's low level. In nominal dollars, future bills will very likely exceed historical highs under business-as-usual energy use.
2. While oil prices will still matter for UH electricity bills, non-energy charges will grow to comprise the predominant share of bills under all scenarios.
3. Holding all other factors the same, potential reduction of electricity demand from energy efficiency improvement could greatly reduce future bills relative to the status-quo reference.

All possible combinations of assumptions are illustrated on an interactive website.

5. ON CAMPUS SOLAR AND BATTERY OPTIONS FOR UH MĀNOA

To consider on-campus options for the university to both lower cost and reduce dependence on fossil fuels, we built an optimization model based on the architecture of Switch 2.0 (Johnston et al., 2019), capacity-expansion software developed for planning whole-grid scale power systems. We added modules to this software that allow for purchased power in accordance with current and projected tariff schedules, including demand charges. Thus, the software can be used to aid efficient planning of a microgrid that is connected to the rest of the grid with a complex array of tariff structures.

We used this model to consider the costs and benefits of on-campus solar installations that are at different stages of planning and development, as well as battery installations optimized in a manner so that they minimize the University's net present value of energy costs, inclusive of both on-campus investment costs and billing charges from HECO.

5.1 PROJECTED COSTS AND SCHEDULE FOR ON-CAMPUS INVESTMENTS

On-campus rooftop solar installations need to be scheduled in conjunction with other campus maintenance and infrastructure improvements. For example, a convenient and economic time to install rooftop solar is immediately after roofs have been replaced or resurfaced. As a result of these and other constraints we scheduled installations on the following schedule, with a maximum installed capacity of 17MW – a conservative estimate of potential based on calculations of Miles Topping. The assumed costs, reported in Table 5.1, are well above projections for the national average for similar-scale installations, but may be realistic for Hawai'i, given the high costs of PPAs in Hawai'i relative to the mainland to date, and the high transaction costs associated with State contracting. Note that if purchased through a PPA, the developer would also obtain tax credits. For some perspective on how conservative these costs assumptions may be, note the current unsubsidized cost of larger-scale rooftop installations is commensurate with what we assume for 2035.[3]

Table 5.1. On-Campus Solar-Photovoltaic Installation Sizes and Assumed Cost.

Year	MW Installed On Campus	Cost per Watt installed	Operating & management costs per Watt
2020	5 MW (PPA)	$6.00	$0.045
2025	5 MW	$4.00	$0.045
2030	5 MW	$3.00	$0.045
2035	2 MW	$2.00	$0.045

3 Lawrence Berkeley National Laboratory's Tracking the Sun report indicates an average installed cost for large-scale rooftop solar of $2.40 per watt in 2018 and 5-7 percent declines each year. Tesla currently advertises an unsubsidized installed price of just under $2 per watt for systems equal to 16.2 kW or larger, including Hawai'i.

5.2 OPTIMIZING SOLAR AND BATTERY INSTALLATIONS

Battery installations are optimized to manage peak loads in conjunction with installed solar, thereby reducing demand charges. In later years, battery discharging can also help to reduce peak load in the late afternoon as solar generation diminishes but demand remains high. The software simultaneously optimizes total investment in batteries and real-time charging and discharging (on 15-minute intervals). The model samples 3 full days from each month of each investment year and one day from each non-investment year, and weights these days to comprise full years in the financial optimization. For each future pricing scenario, the model minimizes the net-present value of total electricity costs assuming a 3 percent discount rate to balance projected future costs against current costs.[4] An example of one day from an optimized plan is illustrated in Figure 11.

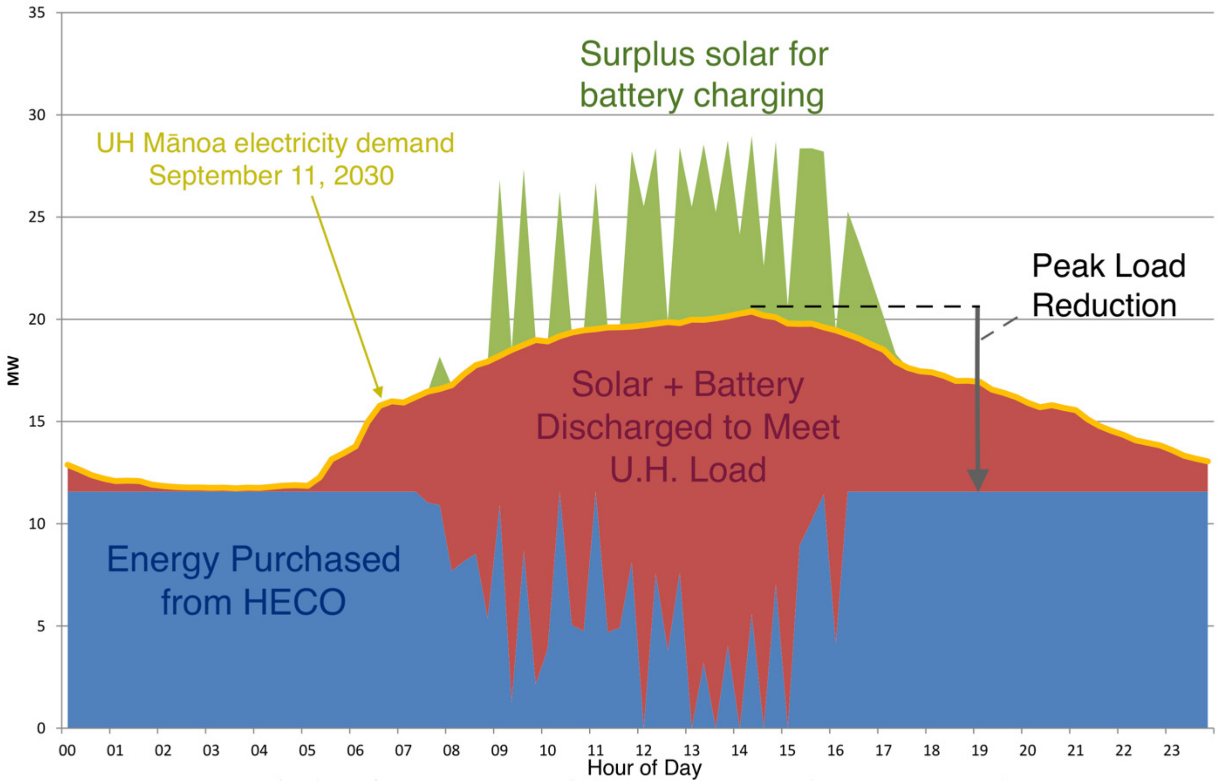

Figure 5.1. Optimized On-Campus Solar and Battery Management.

Notes: On-campus solar and battery installations reduce both energy and non-energy charges. Batteries absorb some energy from up to 17 MW to prevent back feeding electricity into the larger grid, and can be discharged strategically to reduce peak demand and associated demand charges. The graph shows one day from an optimized plan derived by Switch 2.0.

For all scenarios, we optimize battery installations assuming baseline projections for oil prices and PSIP projected net demand. Preliminary analysis found little difference in optimized on-campus investments for other oil price and non-energy charge projections. Battery investment is tied mainly

4 The 3 percent rate equals an assumed 2 percent rate of inflation plus 1 percent real time-value of money.

to the schedule of on-campus solar installations, and is used to smooth out net demand in the middle of the day, and fill in for solar as sunlight diminishes, and thereby reduce peak demand and associated demand charges, which do not vary with oil prices. Batteries also prevent backfeeding in later years. The optimized schedule of battery installations are reported in Table 2.

Note that University savings from demand charges, like per-kWh non-energy charges (such as the PPAC), will mainly be passed on to other HECO customers through revenue decoupling, since the University's peak has no apparent cost to the broader system. Even the system-wide peak should be relatively inexpensive to serve, since the peak has been falling and there exists considerable excess generation capacity in the system.

In other scenarios, we use the software to optimize other forms of on-campus generation in conjunction with Rider Z, discussed in Section 6, but these options are not described in detail here. The software will help the University select a prudent portfolio of on-campus investments to achieve its goals for renewable energy in a cost-effective manner that is responsive to changes in policy and changes in tariff structures.

Table 5.2. On-Campus Battery Costs and Optimized Installation Under Projected Energy and Non-Energy Charges

Year	Battery Cost ($/kWh)	Operating and management cost ($/kWh)	Optimized New Capacity (MWh)*
2020	526	10	0.3
2025	401	10	0.43
2030	335	10	1.05
2035	294	10	0

Notes: *Optimized battery investment is for the scenario with futures oil prices and PSIP-projected load and associated non-energy costs. Optimized investment amounts differ very slightly for other scenarios. Required instantaneous charging or output from batteries is less than 20 percent of storage capacity and should not be a binding constraint.

5.3 PROJECTED BILLS UNDER STATUS-QUO AND RIDER Z

Because non-energy costs are anticipated to grow to comprise a larger share of bills in the future, these investments will be well worthwhile to the University even if they turn out to be more expensive than our assumptions. Note that the assumed costs are gross costs and assume no federal or state incentives. In practice, costs may be less if undertaken by a developer that can take advantage of tax credits, or if Hawai'i's high costs of solar begin to converge toward costs in other states and regions. Note, for example, that as of this writing, Tesla offers an installed price of rooftop solar of less than $2 per Watt for systems as small as 16kW, unsubsidized. This price is less than our assumed cost in 2035 for a 2MW installation, and less than half the price that we assume for 5MW in 2025.

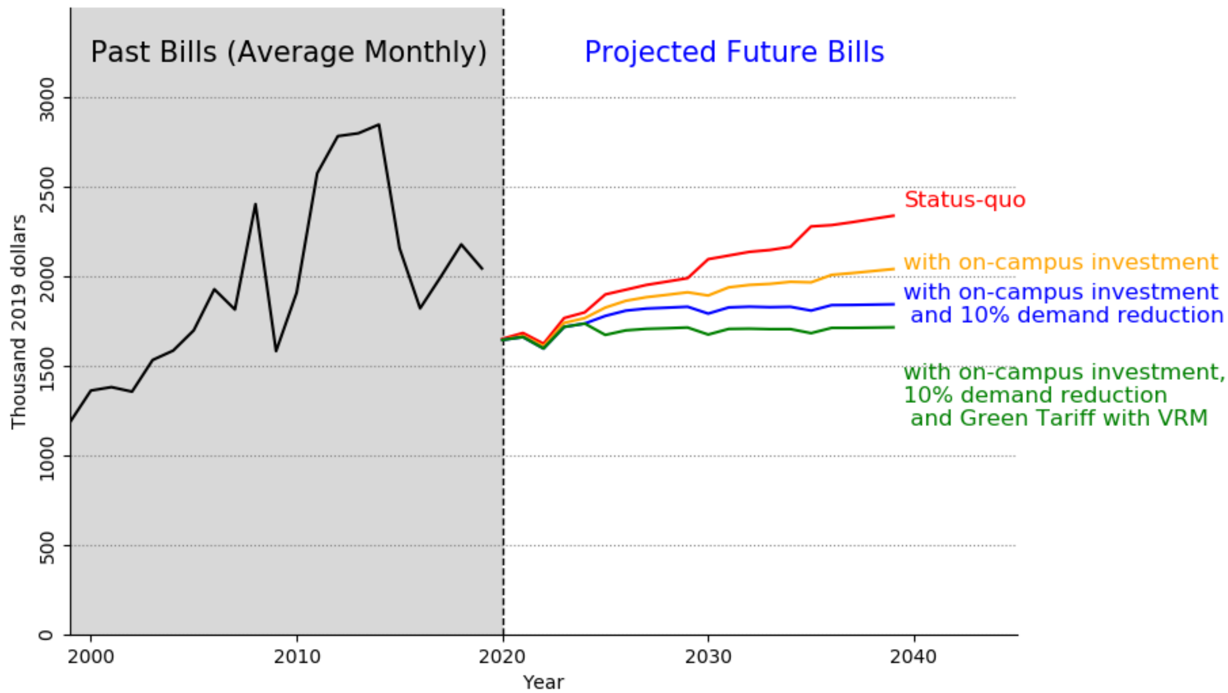

Figure 5.2. Historical and Projected Future Electricity Bills With and Without Optimized On-Campus Investments in Solar and Battery. The graph shows annual average monthly bills for UH Mānoa for four scenarios. The baseline status-quo scenario (red line) without on-campus investment is identical to that shown in Figure 11. The yellow line is a scenario that includes 17 MW PV investment and optimized battery to reduce demand charges. The blue line shows these on-campus investments plus a 10% reduction in electricity demand by 2039, presumably stemming from energy efficiency investments. The green line line includes a 10MW rider Z and virtual rider M. The common assumption of all scenarios is that future oil prices will follow futures prices, there is no broader grid defection, and the generation mix follows HECO's PSIP. All values are inflation-adjusted and reflect 2019 dollars.

There are many other kinds of investments that the University might make to either self-generate and/or shift loads. These investments include ways to improve energy efficiency, consolidate space and thereby reduce electricity demand, smart building control mechanisms that can reschedule loads or store energy and thereby shift timing of demand. These investments could also include installation of thermal generators, cogeneration and optimization of electricity and natural gas use. These options may be considerably more cost effective than solar and batteries. We do not consider these options in this report, but we expect to gradually incorporate more on-campus investment options in the microgrid model as realistic cost and performance specifications become available.

5.3 RIDER M, OPTION B-1.

One option for the University that we do not explicitly consider in modeling, mainly because calculations are comparatively simple, concerns credits that the University could obtain by using batteries (or any other method) to reduce demand during system peak hours between 5 and 9pm. Rider M offers a monthly credit equal to:

0.75 X (Demand Charge) X (kW demand reduction).

Currently, for each megawatt of load reduction between 5 and 9 pm, this credit would equal:

0.75 X $23 X 1,000 = $17,250 per month

One MW of demand reduction could be achieved using a 4-hour, 1 MW battery. The National Renewable Energy Laboratory (NREL) reports that 4-hour batteries typically last about 15 years if cycled once per day. Thus, over a 15-year period, the present value of savings from such a battery would equal approximately $2.5 million if using a discount rate of 3% and $2.2 million if using a discount rate of 5%. On a per-kWh basis, which is how battery prices are normally quoted, these calculations imply a value of battery to the University of $550 to $627 per kWh, because this battery would have 4000 kWh of storage. Battery efficiency would reduce this value by 7.5 to 15%. At the same time, the University’s community college campuses are on a Schedule P tariff with a higher demand charge of $26.5 per kW per month, which would increase this value by 15%. NREL reports that the typical cost of 4-hour batteries is currently $330 per kWh for large-scale batteries, and falling rapidly. (Note that this battery price is less than assumed elsewhere in this report, as reported in Table 5.2.) With well over 10MW of evening load to curtail, the Mānoa campus might enjoy considerable savings ($10 million or more) from installing batteries to curtail as much of this load as possible. Other campuses, especially those that already have solar plus battery installations might benefit substantially from employing its batteries strategically to reduce evening peak demand under Rider M.

The net benefit might be greater if the University purchases batteries in conjunction with on-campus solar under a purchase power agreement (PPA). Such a battery would be implicitly subsidized by Federal and State tax credits that would be enjoyed by the independent contractor that would own and then lease back the system. It is also likely that, barring any significant changes in rate design, the demand charge rate ($23/kW or $26.5 per month) will increase and thereby increase rider M benefit in future years, perhaps substantially.

This potential benefit, however, might be eroded somewhat by the Virtual Rider M that would be associated with Rider Z, which is considered below. It is not entirely clear whether the University can curtail more than 100% of its evening peak demand.

Note that this potential benefit is *not* included in the summary Table 5.3 or on the website that summarizes all scenarios. These incentives to purchase batteries and curtail evening loads are available to all schedule P and schedule DS customers, which comprise a substantial share of Oahu's demand.[5] If these customers begin to take advantage of this opportunity, it would likely raise costs for other customers. The sustainability of this program and of high demand charges in general, is difficult to determine and discussed in sections 7, 8, and 9.

5.4 AVERAGE PRESENT VALUE OF MONTHLY BILL

To summarize projected bills in a single number, and therefore simplify comparisons across scenarios and investment choices, Table 5.3 reports the average present value of monthly electricity bills for UH Mānoa for a few scenarios under moderate assumptions about future oil prices and aggregate costs consistent with the optimal plan.[6] The scenarios include status quo and Rider Z plus VRM agreements, with and without on-campus (behind the meter) investment in solar and batteries, holding all other assumptions the same. The table also reports estimates of HECO's avoided cost and rent, and the collective social impact relative to the status quo. These different components are explained in subsequent sections.

5 Demand charges under other tariffs may be too low for curtailment with batteries alone to be currently economic under Rider M.
6 Future monthly bills, in nominal dollars, were discounted using a 5 percent annual rate and then averaged from 2019 through 2039.

Table 5.3. Monthly Bills and Costs to the University, HECO’s Rent, and Collective Gain for Key Scenarios.

SCENARIO		Energy charge	Non-energy charge	Amortized cost of on-campus investment	UH total month-ly cost (a+b+c)	Marginal cost of serving UH	Average marginal value of 10MW PPA	Cost of 10MW PPA#	HECO Rent (a+b-e +f*-g*)	Collective Change Relative to Baseline (d1–d+h -h1)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Status quo	(1)	467.9	921.1	0.0	1,389.0	509.1	0.0	0.0	880.0	0.0
Status quo with on-campus investment	(2)	395.5	752.4	91.9	1,239.7	439.7	0.0	0.0	708.2	-22.5
Rider Z & VRM with $0.10/kWh PPA	(3)	499.1	839.2	0.0	1,338.3	509.1	61.5	68.6	822.1	-7.1
On-cam-pus solar investment plus Rider Z & VRM with $0.10	(4)	426.7	670.5	91.9	1,189.0	439.7	61.5	68.6	650.4	-29.5

Notes: All values are the monthly amortized values in thousands of 2019 dollars assuming a 5 percent discount rate (3 percent real plus 2 percent inflation) and 20-year amortization. On-campus investment scenarios assume 17 MW of solar eventually installed on campus with batteries co-optimized to reduce demand charges (it does not account for a possible cogeneration facility). The average marginal value of solar (f) includes an estimate of the real-time marginal value of solar provided plus the amortized value of a battery based on costs assumed in the Switch model of Oahu. The Cost of 10MW PPA equals the sum of PPA price (10 cents/kWh) multiplied by the average monthly electricity generated in the dedicated renewable facility.

6. GREEN TARIFF PROGRAM — RIDER Z AND VIRTUAL RIDER M

6.1 THE GREEN TARIFF PROGRAM

Under the Green Tariff, or Rider Z, UH Mānoa and HECO could install a large-scale PV system at an off-site location that would implicitly service electricity demand on the Mānoa campus. For purposes of this analysis, we consider a site on University land in West Oahu, and we assume a project size of 10MW. It is not clear whether the University would employ this particular site for use in a rider M. The University, however, will not directly consume the electricity generated from

Dedicated Renewable Facility. Instead, the University will obtain credits from HECO, and HECO will manage the off-site solar installation as part of the larger grid. The university would provide the land, HECO would elicit competitive bids from independent contractors and pay the winning developer according to the capacity installed. The University would then compensate HECO for the cost of the associated PPA, and credit the university for energy charges in accordance with the average guaranteed production from the off-site solar installation.

The nominal credit will be determined as follows:

$$\text{Credit} = \mathbf{(ECRF - GT\ Rate) \times MWh},$$

where ECRF is the Energy Cost Recovery Factor that embodies average fuel costs as described in Section 2, GT Rate is the per MW cost of the PPA for the new solar installation, paid in accordance with a competitively bid solar development, and MWh is guaranteed average monthly generation from the new solar facility. Thus, the University obtains a positive credit so long as the ECRF exceeds the cost of solar.

A problem with this credit formulation is that the ECRF only comprises fuel costs and will therefore comprise a gradually shrinking share of generation, as the grid transitions toward more renewable energy. Specifically,

$$\text{ECRF} \sim \frac{\text{Total Fuel Costs + Other}}{\text{Fossil Generation + Renewable Generation + Other}}$$

(This expression is approximate, mainly due to nonfuel components of the ECRF.) Over time, the numerator will fall and the fossil share of generation in the denominator will fall and renewable generation will increase. Thus, the faster HECO transitions to renewable generation, the more ECRF will fall, regardless of how the value of solar generation from the dedicated renewable facility changes over time.

The University will still be required to pay all non-energy charges associated with electricity consumed from the dedicated renewable facility, and these charges will likely rise substantially, as described in section 2. Non-energy costs will rise in part because operations and maintenance costs will rise, while aggregate net demand is likely to be stable or falling over time, and in part due to a rise in purchased grid-scale solar, wind and possibly other capital. Thus, a faster island-wide transition toward renewable energy would not only reduce the credit associated with ECRF, but also increase non-energy charges associated with purchased capital. In an extreme case, if HECO were to unexpectedly transition to 100 renewable energy before the end of the PPA, the University would, in effect, be paying twice for power associated with Rider Z: once through the PPA, and again through normal charges, which by that point would include only non-energy charges.

Following an earlier draft of this report, which was shared with HECO in 2018, they revised Rider Z in a manner that partly corrects this problem. Specifically, the tariff sets a *baseline contribution rate* (BCR) for energy use associated with the off-site installation. The BCR effectively puts a cap on the Purchased Power Adjustment Clause (PPAC), the component of non-energy charges associated with capital purchased from independent generators, which is where HECO’s new utility-scale solar and wind purchases will show up on customer bills. Our understanding is that the BCR initially will be set to the level of the PPAC at the time the Rider Z is executed. If the PPAC rises above this baseline, the University will obtain an additional credit that amounts to the difference:

If PPAC > BCR, Additional Credit = **(PPAC – BCR) x MWh**

According to HECO, BCR will be adjusted each year for inflation. The inflation adjustment makes sense if pre-existing capacity payments to independent generators at the time of execution are also adjusted for inflation.

While this additional credit attempts to correct for the possibility of rising non-energy charges stemming from a changing generation mix, it does not correct the problem with the shrinking ECRF. We know of no precedent for this kind of rate design, nor can we see how to connect this formulation to any reasonable interpretation of cost causality, which is a core principle of rate design. In Section 9 we suggest a minor adjustment to the credit that may reconcile some of this disconnect.

6.2 PROJECTION OF PPAC AND ECRF

Documents in PUC DOCKET No. 2016-0328 and 2019-0085 detail PPAC costs for existing independent power plants, and also clarify how payments for new utility-scale PV installations will be folded into the PPAC. Because HECO is planning to replace most power from the AES coal power plant, scheduled to retire in 2023, by installing multiple utility-scale solar systems or other kinds of renewable energy, the PPAC is projected to rise in the future. This increasing trend of PPAC will be accelerated if more utility-scale solar is added to the system than HECO currently plans (see Figure 14).

We believe there is good reason to expect a faster transition to renewable energy. Our own modeling of the power system, echoed in a report developed by Rhodium group, sponsored by Elemental Excellerator, indicates that the least-cost path would install considerably more renewable energy far sooner than HECO's plan, set out in the PSIP or otherwise proposed since that time. To illustrate how the transition toward renewable energy influences the PPAC and ECRF, we projected changes in these measures through current commitments through 2023, and then simulated how both measures would change subsequently with and without continued modest expansion of solar PV (Figure 14).

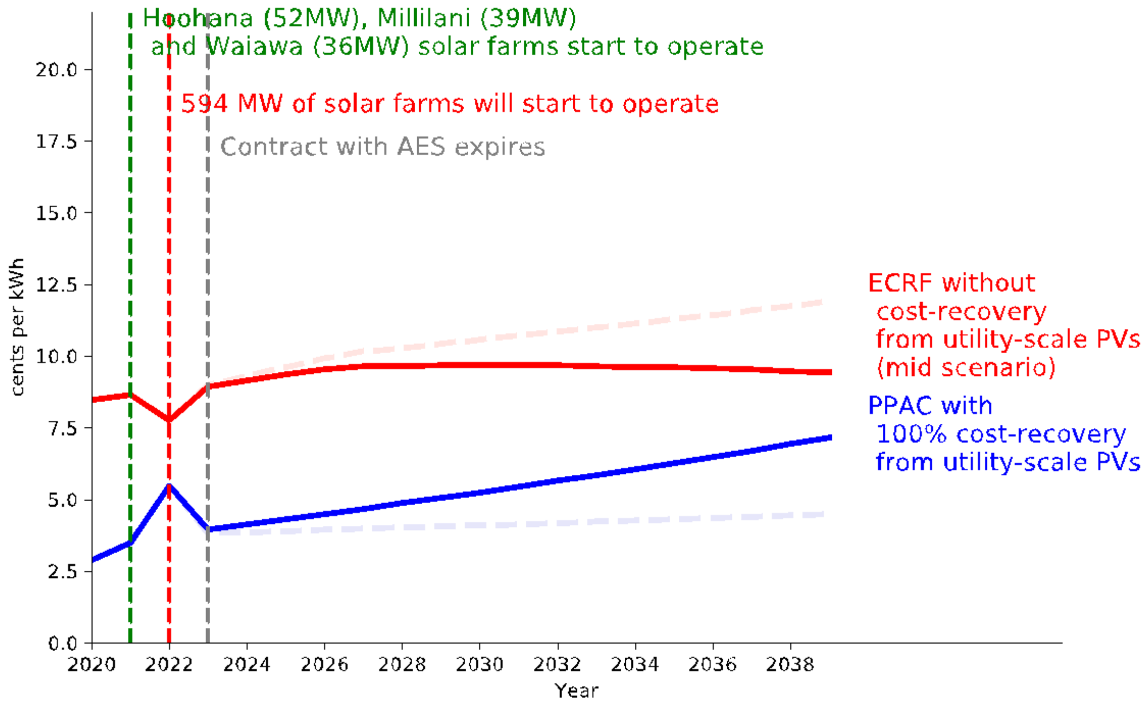

Figure 6.1. Projected PPAC and ECRF from 2020 to 2039

Notes: The figure illustrates the projected PPAC and ECRF. PPAC (blue line) is projected based on the information from the documents in PUC Docket No. 2016-0328 and 2019-0085. The projection of ECRF is the same as in Figure 7 with the mid oil price scenario. Between 2020 and 2023, the installation of utility-scale PVs is following HECO's RFP. The light dash lines illustrate the case that there is no extra utility-scale PV installation after 2024. The solid lines show the projection results with an assumption that an extra 10 MW utility-scale PVs will be installed in Oahu each year after 2024 until 2039.

In our analysis of Rider Z, we make similar adjustments for plans that are both consistent with the PSIP and with the optimized plan that comes from Switch 2.0. The website that accompanies this report includes projections for both scenarios in conjunction with other scenarios.

6.3 GREEN TARIFF WITH VIRTUAL RIDER M

Rider Z makes no account of a battery installation that may accompany the off-site dedicated renewable energy facility. Most recent solar installations, however, do include batteries, and these increase the cost of any PPA. One reason for including batteries with solar installations is that the power plant can be operated more like a traditional power plant. There may also be small efficiency gains for having the battery close to the solar panels that charge the batteries. The most important reason, however, is that tying the battery installation together with the solar installation allows the developer to collect subsidies (federal and state tax credits) for the battery that would not otherwise be available if it were a stand-alone installation. To obtain subsidies, the battery must be charged using on-site solar only. It is not clear whether this constraint on battery use would have a meaningful impact on the battery's value to the system.

To compensate the University for any battery associated with Rider Z, HECO has proposed a Virtual Rider M (VRM) option B. The rider would adapt the existing (non-virtual) Rider M option B, which rewards commercial customers that are willing to limit their normal demand during the system peak hours, between 5:00 pm and 9:00 pm, whenever HECO requests that they do so. Customers opting into this program are rewarded in the form of a reduced demand charge, based on the amount of load that the customer is willing to shed when requested. The idea with VRM is that the off-site battery could be employed to "virtually" reduce the University's electricity demand, and so the University can obtain a credit, accordingly. Most batteries installed with utility-scale solar systems are four-hour batteries, which neatly fits the four-hour window from 5-9 pm.

The battery would, almost surely, never be employed in this particular manner; it would presumably be operated in a manner most suitable to keeping overall system costs low. But the University would be compensated for the battery *as if* it could be used in this manner.

The amount of credit associated with VRM will depend on the rate of demand charge and the size of the installed battery. The equation for computing the credit is as follows:

Credits from VRM = **Demand charge x 0.75 x Size of battery (kW)**

A battery that can emit 5 MW for four hours, yielding a total of 20 MWh of storage, could be employed to curtail 5 MW of load during the 5:00 pm to 9:00 pm curtailment period. With a current demand charge of $23 per kW, the University would obtain an additional credit of $23 X 0.75 X 5,000 = $86,250 per month, or a little over $1 million per year, if a 5MW/20MWh battery were installed in conjunction with an off-site solar PV system, which is what we assume.

6.4 PROJECTED BILLS WITH A RIDER Z AND VIRTUAL RIDER M

We simulated bills for the University with a 10MW Rider Z both with and without a Virtual Rider M (VRM), and in each case with an 8 cent per kWh and 10 cent per kWh PPA. We also considered the situations with each of the three oil price scenarios (low, mid, high) and two different generation mix scenarios, PSIP and the optimal plan selected by Switch 2.0, as well as different on-campus management plans.

The value of Rider Z to the University and its impact on other customers is largely independent of other actions that the University is currently contemplating to reduce its electricity bills and reduce fossil fuel use. As a result, we focus here on scenarios that consider Rider Z in comparison to the status quo, with no additional on-campus generation or storage. Other scenarios can be viewed at the website we have referenced in other parts of the report. If, however, the University were to consider a larger Rider Z installation, or find ways to increase solar generation on campus well beyond the currently anticipated 17 MW, then the value of the Green Tariff to the University could be considerably less than estimates we provide here. On-campus generation benefits from reducing both energy and volumetric (per-kWh) non-energy charges, as well as demand charges, and these benefits would likely outweigh the potentially lower cost of a ground-level utility-scale installation in sunnier Dedicated Renewable Facility.

Figure 6.2 shows projected electricity bills for the University going forward with and without a 10MW Rider Z and Virtual Rider M. The depicted savings could be interpreted as a reasonable baseline in the middle of a wide range of possibilities. The time path of projected bills under other scenarios can be viewed at the linked website.

Figure 6.3 summarizes the net-present value (NPV) of Rider Z and Virtual Rider M to the University under a wide range of scenarios, each one assuming a 10MW installation under a PPA of $0.10 per kilowatt hour. These are estimates of the University’s bottom line. The results show that the University is unlikely to see an overall benefit under the Rider Z alone, unless oil prices are high (top panel of Figure 6.3). If, however, the 10MW installation includes a 20MWh battery for the same $0.10 per kilowatt hour price (which is similar to recent PPAs in Hawai‘i), then the additional credits associated with the Virtual Rider M will almost certainly result in net savings for the University (bottom panel of Figure 6.3).

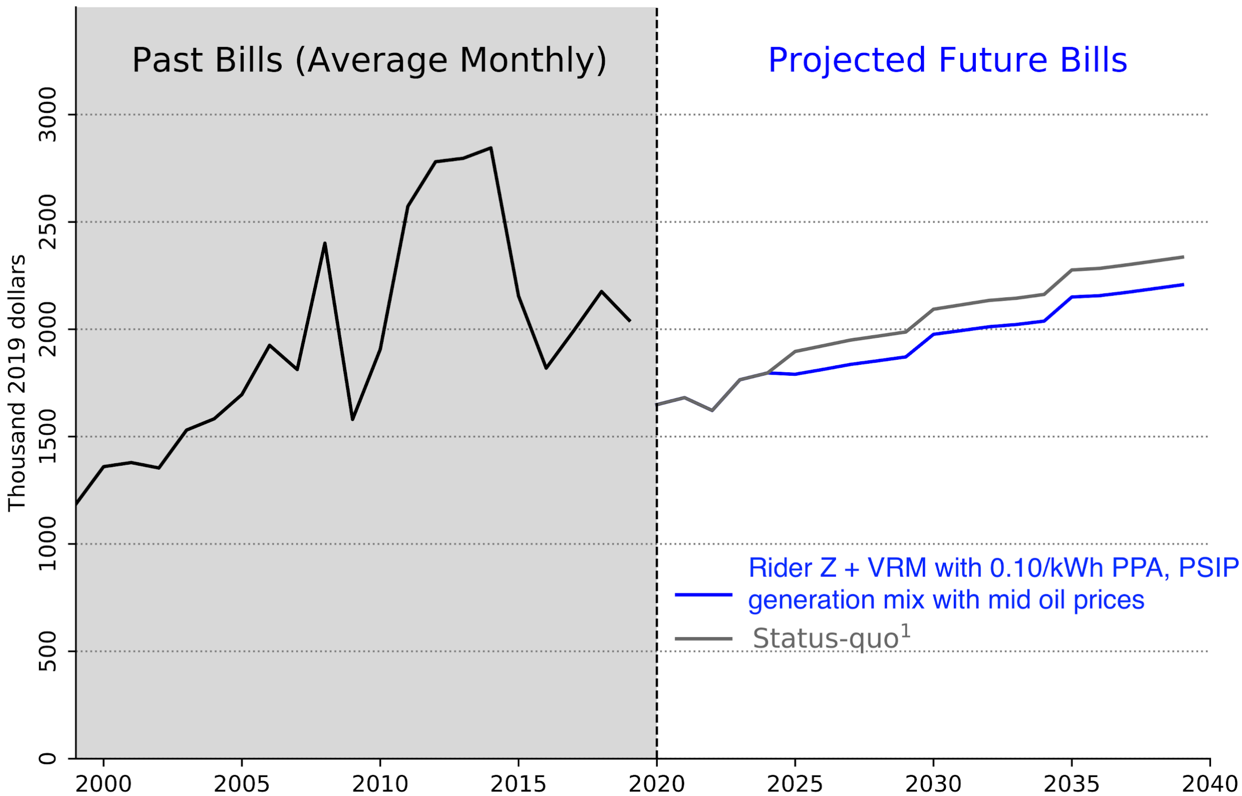

Figure 6.2. Projected monthly bills for UH Mānoa with and without a Rider Z with VRM under baseline projected oil prices and generation mix that accords with HECO's PSIP.

Notes: The figure shows projected bills (in constant 2019 dollars) under projected oil prices (based on futures prices as of May 2020) and no further on-campus investment in generation, with and without a 10 MW Rider Z based in Dedicated Renewable Facility priced at 10 cents per kWh. This scenario assumes the installation and PPA include a 5MW, 20Mwh battery which gives the University a credit associated with a Virtual Rider M (VRM). Without the VRM, the University would gain much less, and ultimately save very little under this scenario. And if oil prices were to fall or Hawaiian Electric Company were to transition to renewable energy more quickly than the PSIP, the University is projected to pay more under a Rider Z. Other scenarios are presented online at this link.

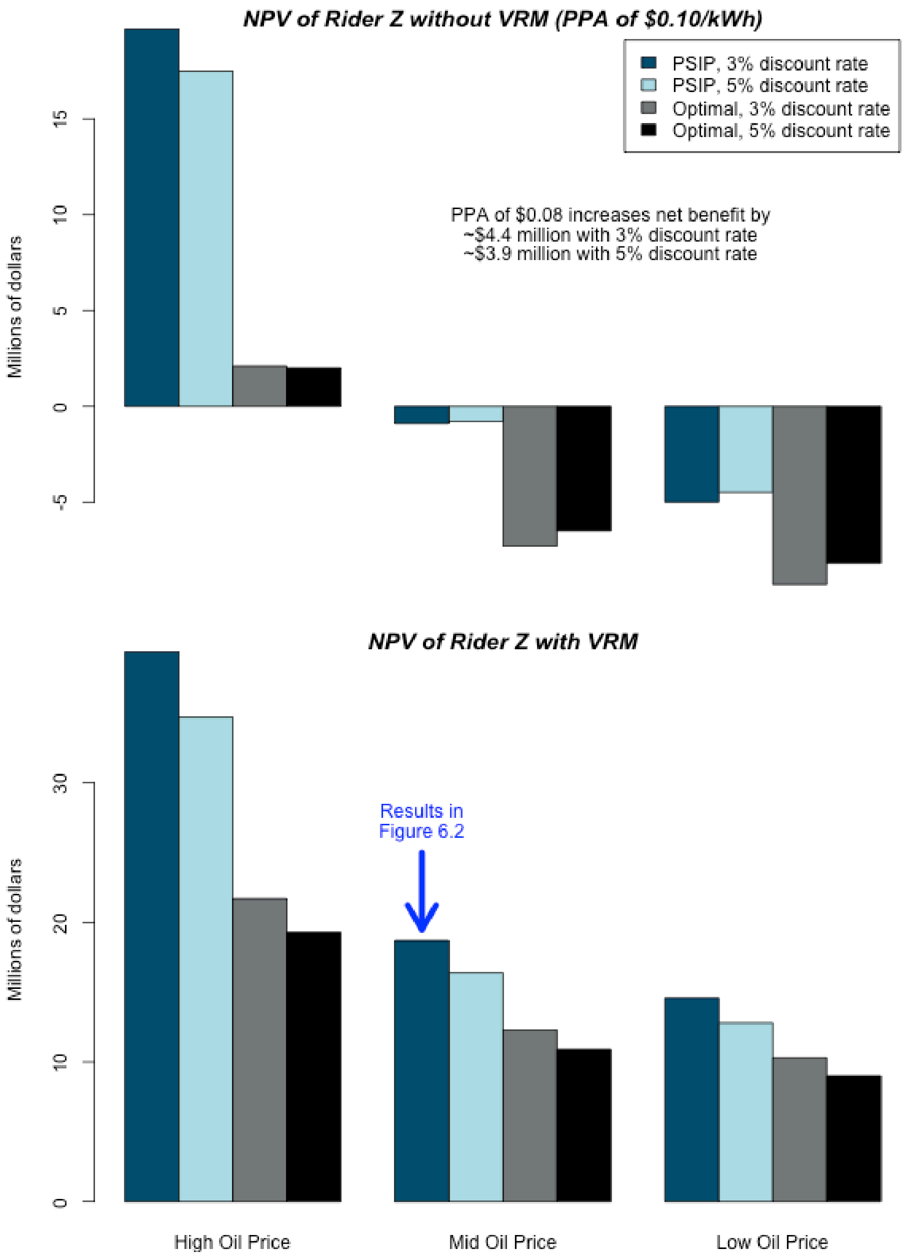

Figure 6.3. Net present value of a 10 MW Green Tariff to UH Mānoa, with and without Virtual Rider M.

Notes: Each bar indicates the net present value (NPV) of savings to the University from a 10 MW installation of off-campus solar under a proposed Rider Z tariff agreement under a given scenario. In all scenarios depicted, the assumed cost of the purchase power agreement is 10 cents per/kWh, plus the opportunity cost of the land that the University donates to the project. The scenarios differ according to the assumed oil price path (described in section 3), the assumed discount rate, and overall changes in generation mix (HECO's PSIP or optimal plan selected by Switch 2.0). The bars in the top panel depict a Rider Z without a VRM (i.e., no battery). The bars in the bottom panel depict a Rider Z with VRM. The bill savings indicated in Figure 6.2 accord with the scenario indicated in the bottom panel.

Because a PPA will cost more if the installation includes a battery, the extra benefit would need to exceed the extra cost of the PPA. For each 0.01 difference in the price of the PPA, the net difference to the bottom line would be between $2 million and $2.2 million, holding all else the same. Since the Virtual Rider M amounts to approximately a $17 to $20 million net-present-value benefit to the University, a PPA without battery would need to be $0.08 to $0.10 per kWh cheaper to be comparable to an otherwise similar PPA with battery. The implied value of the battery amounts to about $850 to $1000 per MWh of storage, which is considerably higher than the typical cost of large scale battery installations today. In other words, credits to the University from the Virtual Rider M far exceed HECO’s avoided costs, such that most of this benefit to the University would likely reflect costs transferred to other customers.

7. AVOIDED COST AND HECO’S RENT

In previous sections, we noted how actions by the University to reduce its bills may result in more savings to the university than HECO would save in terms of its avoided costs. We also explained how Rider Z and Virtual Rider M (VRM) would provide credits to the University that may exceed or fall short of the value of energy or services provided by a solar-plus-battery installation on University land in an off-site dedicated facility. In this section, we explain how we quantify these impacts on other customers.

7.1 ESTIMATING HECO’S AVOIDED COST

To estimate the effect of Rider Z on other customers, we need to estimate how much the new solar facility reduces HECOs generation costs and compare this avoided cost to the size of the credit provided to the University. Because solar supply is variable and intermittent, both the amount of power supplied and its value to the system varies by time of day, season, and the particular weather circumstances. The calculations can be complex. For an installation that includes batteries, we must further account for the value of storage in relation to credits provided by the VRM.

Similarly, if the university changes its demand for electricity, the effect of shifting demand on HECO’s costs will depend on the time and circumstances of those shifts, as well as the amount that its electricity demand changes.

To estimate these values, we estimated real-time marginal costs using Switch 2.0, a planning model that optimizes the island-wide generation mix under each oil price scenario, and otherwise makes the similar assumptions as those in a current docket before the Public Utilities Commission where the model has been proposed by Ulupono as a benchmark for utility performance. An unusual and especially useful feature of Switch is that it nests real-time operation of the grid within the broader investment optimization framework. It accounts for the synchronous covariation of weather, potential renewable supply, and demand across the whole island using a sample of days that are then weighted to represent the typical distribution of outcomes over whole years extending out to 2050.

Once the optimal path of investment is determined, Switch can find the real-time marginal cost of power for a full chronological sequence of jointly-determined weather and demand circumstances as reflected in history, and rescaled for projected future demand scenarios. We synchronize the weather and island-wide demand with demand by UH Mānoa, as well estimated hourly power supply from a test site in West Oahu where the 10 MW solar plant might feasibly be installed in conjunction with Rider Z. Because the size of the solar installation is small relative to island-wide supply and demand, we can approximate the value of power supplied by the marginal cost calculated by Switch.

Note that the marginal cost calculated by Switch 2.0 differs somewhat from the so-called "system lambda" generated by HECO's current automatic generation control software (AGC). There are a few key differences. First, it is not clear whether current operations software optimizes a system appropriately when there is storage and substantial share of intermittent renewable energy. Second, in HECO's current operations management, they often schedule many power plants outside of the automatic generation control software.[7] In time, presumably HECO would adopt software that would control its system in real time in a least-cost manner, subject to reserve requirements, similar to the manner assumed in Switch 2.0.

In the near term, however, the system lambda from HECO's AGC likely imparts a reasonable marginal cost. Most of the time the marginal cost will be tied to power from one of HECO's older oil-fired power plants, all of which have similar heat rates and fuel costs. Thus, at least for the next few years, solar provided by the dedicated renewable facility would likely displace generation from these oil-fired power plants (Kahe and Waiau). Marginal avoided costs from these power plants might serve as a reasonable alternative value to Switch for estimating the near-term value of energy provided by a dedicated off-site solar installation.

In time, however, we expect HECO will have adopted control software that better reflects the more complex management of renewables and storage, and will indicate a more appropriate marginal cost in its reported system lambda. We therefore see no technical reason why a real-time account of marginal costs cannot be used to estimate avoided costs for small-to-medium-sized renewable power sources feeding into the grid. Such a measure is presumably used for compensation under Schedule Q and other, larger Qualified Facilities, under avoided cost

7 This was evident on a visit to HECO's control room.

compensation rules (see this link for details about Schedule Q and this link for monthly avoided cost values). The calculations underlying avoided cost may need to be updated in the future when Kahe and Waiau no longer serve as the typical marginal source of power. Under an optimized plan (Switch 2.0), this could happen fairly soon. Under HECO’s current plan, it would not happen for a number of years.

7.2 HECO’S RENT

HECO’s rent is their bottom line—the amount of revenue it receives from the University net of the incremental cost of providing electricity to the University. Rent contributes to HECO’s fixed costs and earnings. Note that impacts on HECO’s rent do not, in practice, have any direct influence on HECO’s profit, since they are allowed to adjust prices over the long run to collect the same amount of total revenue. Thus, positive changes to HECO’s rent likely imply reductions in costs for other customers, while negative changes to HECO’s rent likely imply increases in costs for other customers. The measure is given by

HECO Rent = Revenue + Value R.E. - Cost U.H.

where *Revenue* is billing revenue from UH Mānoa net of any PPA costs that are passed through HECO in Rider Z; V*alue R.E.* is the incremental value of renewable energy provided by the off-site dedicated renewable energy facility; and *Cost U.H.* is the incremental cost of serving UH Mānoa’s demand, net of on-campus generation or load shifting.

Because we do not have a perfect accounting of HECO’s costs, and cannot entirely divine its future management decisions, we estimate costs using Switch 2.0, as described in the last section. This model estimates the least-cost way for HECO to generate and balance power going forward while satisfying renewable energy goals for the state. An early version of this open-source model is described in this UHERO working paper and the version used in this analysis mirrors that used by Ulupono in current regulatory proceedings on performance based regulations, docket number 2018-0088, which can be accessed here).

Table 5.3 reports avoided costs and HECO’s rent for a few benchmark scenarios, together with the University’s billing summary. Instead of a time path of bills or costs, it reports a single number for each scenario, equal to the average monthly present value of rent over a 20-year horizon. These scenarios only consider “optimal plan” scenarios based on Switch 2.0 with middling oil prices and no additional grid defection. We have no reasonable way of estimating HECO’s rent under the PSIP. But in earlier years of that plan, avoided cost would likely be commensurate with what HECO reports each month and linked above.

HECO's rent varies across scenarios. In the four midling scenarios reported in Table 5.3, it varies from a little over $650 thousand to $880 thousand per month, largely in accordance with the University's costs. That is, the higher HECO's rent, the higher the University's energy cost, with the highest being the status quo. HECO's rent actually declines more than dollar-for-dollar with the University's savings, which is reflected in the negative values in column (i) of Table 5.3. This column gives the collective gain to the University and HECO combined, which is negative in all scenarios we examined, except those where the off-campus solar plus battery installation under Rider Z and VRM can be purchased under a PPA of 8 cents per kWh, which is slightly less than assumed in the optimal plan. In those cases, the extra savings would accrue entirely to the University. Note declines in HECO's rent will not influence their bottom-line profitability, but rather reflect costs that will be passed on to other customers. Thus, for the central projections reported in Table 5.3, other customers will pay about 114% of the University's savings from Rider Z plus VRM, and about 115% of the University's savings from on-campus investments in solar and battery.

At face value, these projections may not seem especially supportive of the Green Tariff. Note, however, the substantial size of HECO rent in all scenarios, and that the University has many options for self-generation, including many options that are not depicted. All of the University's efforts to reduce energy costs, improve efficiency, and self-generate will reduce this rent, and thereby cause prices for other customers to rise. An argument in favor of the Green Tariff is that it may slow or forestall some of these efforts by the University, preserving rent, and help keep other customers' tariffs lower than they otherwise could be.

8. OTHER RISKS TO THE UNIVERSITY

Some risks to the University are not apparent from the range of scenarios we have presented. Here we briefly review some of these other risks.

Although Rider Z combined with Virtual Rider M (VRM) shows notable savings to the University relative to the status quo, it does less to help the University manage rising non-energy costs. In fact, it may inhibit its ability to manage these costs. Our analysis of an on-campus renewable energy strategy shows how much more the University stands to gain by embracing on-campus generation opportunities. We anticipate that there are many other opportunities for on-campus investment beyond those considered in this report. Some of these options are shown on the interactive website that we reference, such as on-campus cogeneration, but others are likely available. In particular, we assume a very high cost of on-campus rooftop solar and a conservative estimate of on-campus solar capacity. Future battery costs and other forms of implicit energy storage, used for demand in hot water or air conditioning, might facilitate reduced demand charges, including use of Rider M as described in section 5.3.

These results suggest that the largest financial risk to the University for engaging in a Green Tariff concerns the degree to which doing so forecloses future opportunities that might be more financially beneficial. For example, most of the gains would accrue through a VRM. But it is not clear whether the University can curtail more than 100 percent of its 5-9 pm evening demand. If not, that savings from the Green Tariff would foreclose some opportunity for using the actual (non-virtual) Rider M.

Another risk is the possibility that HECO transitions to low-cost renewable power more quickly than projected by even the Switch 2.0 optimal plan. The risk to the University of a quicker transition is that solar and wind, the most cost-effective renewables, have no fuel costs. More renewables sooner would therefore increase non-energy charges faster than we project, while driving down energy charges and the associated Rider Z credit. Note that even the optimal plan uses fairly conservative assumptions about batteries and various kinds of renewable energy costs. There is considerable uncertainty about how fast costs will actually fall as the technology advances. Most estimates indicate that solar and battery costs fall by over 20 percent each time global cumulative production doubles. Thus, if either costs specific to Hawaiʻi come down, or the world accelerates its transition away from fossil fuels, the value of the Green Tariff could be less than indicated in any of the scenarios.

As proposed, this tariff commits the university to paying all non-energy costs. As non-energy costs rise, many of HECO’s customers will look for ways to avoid them through self-generation, demand management, and efficiency improvements. Since these investments are valuable to the

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University, it is likely that they will be valuable to other customers, too, such as employing rooftop solar and batteries under Rider M. The more customers find alternatives to HECO, the more net load will decline and the more non-energy costs will rise. This dynamic has been called a potential "death spiral" of grid defection. It now appears to be economic for customers with a capacity to self-generate to do so. As a result, our scenario of 30% grid defection may be too optimistic.

If substantial grid defection begins to occur, or costs otherwise escalate because other large-scale customers manage their electricity load to reduce demand charges and increase related credits, like Rider M and VRM, then non-energy charges could escalate more than our worst projections. Given the State's ambitious renewable energy goals, rapidly changing technology, and the fact that existing rates increasingly depart from fundamental costs, the likelihood of substantial changes in rate structures over the next 20 years is high. A current proceeding before the Public Utilities Commission investigating Distributed Energy Resource Policies (Docket 2019-0323), within which HECO has submitted an Advanced Rate Design proposal. It is not clear to us that this proposal or any subsequent refinements would resolve any of problems with rate design presented here. It is conceivable, however, that following this proceeding or some future one, demand charges could be adjusted or eliminated, or tariff components could be changed to better align rates with costs. It is therefore unclear how Rider M, Rider Z, and VRM would be altered as a result. This prospect creates an unquantifiable risk to the University, as well as a complication for the broader system as HECO and regulators try improve rate design going forward.

Due to these uncertainties, the University has negotiated an exit clause from the Green Tariff that would allow the university to forfeit the off-site PPA to Hawaiian Electric Company together with any credits it may provide, positive or negative. This exit clause limits the downside risk of Rider Z and VRM to the loss of land on which the solar was installed, at least over the duration of the PPA.

9. CONCLUSIONS AND RECOMMENDATIONS

It is an accepted principle of utility regulation that rates ought to reflect underlying costs.[8] As renewable energy has grown in Hawai'i, we see a growing mismatch between rates and underlying costs, and this mismatch can lead to inefficient use of resources. The University, for example, currently has a substantial incentive to self-generate and curb evening demand using batteries or other methods. Such investments, however, would yield benefits to the University that far exceed their value to the broader electrical system. Much of the University's savings would therefore reflect costs that are transferred to other customers.

Similarly, credits from Rider Z may exceed or fall short of the value associated with the off-site solar system, depending on how oil prices evolve and how quickly the system transitions to renewable energy. At the same time, VRM provides credits that appear to far exceed the cost of purchasing batteries. The value of these credits bear no apparent connection to costs avoided by HECO from a solar installation or solar-plus-battery installation. The tariffs would exacerbate current mispricing and could complicate future efforts to align pricing with the State's renewable energy goals. To resolve these problems, we recommend that all parties consider a tariff that provides credits that are more clearly aligned with avoided costs.

We see three simple ways to calculate a credit that roughly corresponds with avoided costs. One method would be to credit the University in accordance with the system lambda multiplied by power provided. This calculation could be made on any reasonable time interval to account for the varying supply of renewable power as well as time-varying demand and system constraints. A second method would be to credit power generated based on avoided cost measures already calculated each month in conjunction with past Qualified Facilities.

A third method, one that would appear similar to the current formulation of Rider Z, would credit the University based on an ECRF that was adjusted for the share of electricity generated from fossil fuels. To clarify this idea, recall that the approximate calculation of the ECRF given in Section 6:

$$\text{ECRF} \sim \frac{\text{Total Fuel Costs + Other}}{\text{Fossil Generation + Renewable Generation + Other}}$$

8 See, for example, Lazar (2016). Although the principle that costs ought to reflect underlying costs is broadly accepted, there do appear to be differing views about how that allocation ought to be done.

The main problem with this calculation is that renewable generation that will be paid on a capacity basis, mainly through PPAC, is in the denominator of this expression, such that, all else the same, the ECRF and the associated Rider Z credit will decline the faster Oahu transitions toward renewable energy. If, however, the denominator only included generation associated with the numerator, i.e.,

$$\text{Adj. ECRF} \sim \frac{\text{Total Fuel Costs}}{\text{Fossil Generation}}$$

then the credit would serve as a more reasonable approximation of per-kWh costs and fossil fuel use avoided from the renewable energy facility.

Resolving the problems with Rider M and Virtual Rider M is more difficult, for they connect to deeper challenges with demand charges and other aspects rate design that may not be sustainable as the renewable energy transition progresses and the cost of batteries continues to decline. It would be prudent to develop a Green Tariff that both reflected underlying avoided costs and was separate from other aspects of rate design.

There ought to be better ways to compensate renewable energy and demand management. There exist well developed methods for calculating location-specific marginal costs, and these underpin pricing in many regions of the country and world that have wholesale markets. While Hawaiʻi does not have a market, these same calculations can be made using system management software that is readily available. Development and real-time disclosure of these marginal costs would be a useful precursor to improved rate structures to appropriately compensate small-to-medium-size providers of power and grid services that the University and other customers should be capable of providing.

Longer term, the problem of cost transference could be resolved with a two-part tariff that includes a more substantial fixed charge plus variable per-kWh charge, with the per-kWh charge connected to marginal cost. Similar tariffs are common in Hawaiʻi for water billing, but there remains considerable reticence in energy policy for adopting such tariff structures, although they do exist in some areas, such as Georgia Power. One of the more difficult challenges with a two-part tariff likely pertains to formulating the way fixed charges ought to be allocated across different customers and different customer classes. Depending on how this is done, it may create other kinds of perverse incentives, and might be employed to alleviate or exacerbate concerns about equity. A second challenge would involve careful monitoring of HECO’s operations to assure that reported marginal costs correspond to prudent management of the system, for it is not entirely clear that that HECO has a strong incentive to minimize costs in the current regulatory environment. Hopefully HECO’s incentives will improve imminently under new performance-based incentives under deliberation by the Public Utilities Commission, but it will take time to learn whether the incentives work as intended. For more on the issues that arise from per-kWh hour charges departing sharply from marginal costs, see Coffman et. al. (2015), Jandoc and Roberts (2015), and Borenstein and Bushnell (2018).

Unfortunately, the structure of the proposed Rider Z and VRM is not consistent with cost-based rate design. Part of this inconsistency stems from the preexisting mismatch between costs and rates, such as demand charges connected to a customer’s peak load, and high fixed costs that are recovered from per-kWh rates. UH Mānoa’s peak tends to be in the middle of sunny hot days, which were expensive to serve in the past but will be among the least expensive hours to serve in the future, due to the growth of solar generation. Thus, just as demand charges have risen to comprise a larger share of the bill, the system is changing to make these charges less aligned with system costs. Rider Z and Virtual Rider M make no effort to correct this mismatch between customer bills and underlying costs, and will only serve to exacerbate these incongruencies if these proposed tariffs are accepted as proposed.

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