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Integrating Renewable Energy: A Commercial Sector Perspective on Price-Responsive Load-Shifting

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1. Introduction

Renewable energy in Hawaii has grown rapidly over the last decade. Largely from the expansion of solar photovoltaic (PV) and wind energy capacity, net electricity sales from renewable energy have increased from 9% in 2008 to 28% in 2017 (Hawaiian Electric Companies, 2008-2017; KIUC, 2008-2017). Current plans to meet Hawaii's Renewable Portfolio Standard (RPS) goal of 100% net sales of electricity through renewable sources by 2045 focus on massive integration of intermittent renewable sources and, towards that end, implementing pricing mechanisms to better match demand with supply.

Though there have long been options for moderate time-varying rates amongst customer classes, the move towards large-scale adoption of intermittent sources of renewable energy prompts the need for more aggressive pricing policies. For example, the Hawaiian Electric Companies[1] is piloting a time-of-use (TOU) program for the residential sector that has a more than 25 cent spread in prices between on-peak and daytime hours (PUC, 2016a; HECO, 2018a) and there are current considerations within demand response (PUC, 2018a). Amongst the existing few rate schedules with time-varying elements for the commercial sector, the price differences are relatively modest, are not aligned to current system costs and are far from dynamic. The size of the load demanded from commercial customers—comprising 71% of sales statewide (DBEDT, 2017)—suggests there may be opportunities for peak load reduction and shifting electricity usage to times when renewable energy is most available.

In commercial and industrial (C&I) sectors across the U.S., there has been a longstanding practice of assessing demand charges to capture customer-specific fixed costs of providing capacity (Veall, 1983; Berg and Savvides, 1983; Seeto et al., 1997; Borenstein, 2016). The two-part tariff applies an *energy charge* for all kilowatt hours (kWhs) of consumption and a *demand charge* based on the maximum level of power consumption (kW) over a given period (Veall, 1983; Berg and Savvides, 1983; Hausman and Neufeld, 1984; Mountain and Hsiao, 1986; Neufeld, 1987; Seeto et al., 1997).[2] A purpose of these demand charges is to help prevent sharp peaks, which typically occur due to extreme temperatures, resulting in smoother demand profiles over the day and between seasons (Taylor and Schwarz, 1990). Demand charges that are non-coincident to the system peak do little to help with balancing challenges and increasingly misalign with the adoption of renewable energy resources. In particular, those levied midday may directly conflict with goals to adopt more solar PV.

Given the growth of intermittent renewable energy and "smart" grid improvements such as advanced metering infrastructure (AMI), there is a growing sentiment of demand charges as an outdated, suboptimal pricing mechanism. Rather, greater efficiency can be gained through time varying pricing that can effectively deployed using AMI. This would need to be paired with more direct ways of capturing the likely shortfall for the entirety of fixed costs (as demand charges have historically captured such capacity costs), possibly through customer-specific fixed charges that reflect service levels (Borenstein, 2016). However, there is

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[1] Hawaii's largest utility, which serves Honolulu, Maui, and Hawaii County.

[2] For a detailed history of the Hopkinson tariff which was first proposed in 1892, see Hausman and Neufeld (1984) and Neufeld (1987).

growing debate as to what effect increasing fixed charges may have as well (Tong and Wellinghoff, 2015).

In contrast to time varying pricing, a time invariant rate leads to inefficiencies because consumers are paying for the average cost of generation – meaning that they are paying too much during times when generation costs are low and too little when generation costs are high. There are many types of time varying pricing strategies, including real-time pricing (RTP), time-of-use (TOU), critical peak pricing (CPP), and critical peak rebates (CPR). RTP is the theoretical first best solution, at least when assuming prices clear instantaneously. In setting price equal to the marginal cost of generation, RTP is able to reflect incremental price fluctuations from integrating intermittent resources. Critics argue, however, that RTP can expose both customer and utility to risk in price and quantity fluctuations (Borenstein, 2005a; Borenstein, 2007b).

Other forms of time varying pricing mechanisms are somewhere between flat rates and RTP. TOU rates attempt to approximate marginal cost across discrete periods of the day and can be set monthly, seasonally or annually. TOU rates provide price certainty, thus limiting risk to consumers, but are also much less efficient because the time-scale is considerably "lumpier" than RTP. CPP can be implemented as a standalone program or layered onto other rate structures like TOU. CPP temporarily imposes elevated prices during a limited number of "critical events" (e.g. during a heatwave) allowed in a given year. These critical event hours are typically announced a day ahead or within hours. While TOU captures only a small fraction of the efficiency gains that can be realized through RTP (Borenstein, 2005b), CPP coupled with TOU can potentially come close to the efficiency of hourly RTP (Blonz, 2016). CPR is in theory identical to CPP, paying customers for reducing their electricity consumption during critical events, though in practice can incent customers to increase their baseline consumption to get paid for such "reduction" later (Borenstein, 2005a).

Utilities across the U.S. and globally have implemented time varying pricing for C&I customers. As of 2016, 260 utilities across 47 U.S. states offer TOU pricing for C&I customers while 38 utilities across 24 states offer RTP (EIA, 2017b). As the most prevalent form of time-varying pricing, TOU rates date back to the 1970's and 1980's, some as voluntary, and others as mandatory programs (Chung and Aigner, 1981; Hirschberg and Aigner, 1983; Aigner and Hirschberg, 1985; Woo, 1985; Jessoe and Rapson, 2015). With advances in technology, policy objectives to offer "retail choice" and to facilitate demand response, utilities began offering RTP in the 1990s often on an opt-in basis (Barbose et al., 2005). Wang and Li (2015) document a total of 408 TOU programs for C&I customers, 70% of which are opt-in, 3% are opt-out, and 25% are mandatory. In practice, RTP is typically implemented on a day-ahead basis, where all hourly prices are announced at one time the day before. This is in contrast to truly real-time prices where customers are either notified with updated prices roughly an hour prior to becoming effective (hour-ahead)[3] or indexed to the real-time spot market.[4] Day-ahead pricing is less efficient than truly dynamic pricing, with inefficiency increasing when actual conditions deviate strongly from the forecast, but also provides some limit to volatility.

[3] For instance, see Georgia Power (Georgia Power, 2015).

[4] New Jersey, Maryland, and Pennsylvania are indexed to the PJM spot market (Barbose et al., 2005).

This report provides a review of existing literature on the responsiveness of C&I customers to time-varying pricing and, for illustration, a presentation of C&I sectors load patterns and rates on Oahu with publicly available data. The purpose is to gain insight into the potential impacts of implementing a form of RTP or time varying pricing more compatible with renewable energy integration to help achieve Hawaii's RPS. Section 2 summarizes the existing literature on responsiveness to time varying pricing in the C&I sector; section 3 reviews HECO's existing C&I rate schedules and the types of end-use customers on each rate schedule; section 4 presents publicly available load curves for Oahu's C&I sectors to show daily usage trends and discusses how various sectors might experience RTP in comparison to current time invariant rates based on existing demand and supply-side patterns; and section 5 provides concluding remarks.

2. C&I Time Varying Pricing

Studies on the effect of time varying pricing within the C&I sector find that customers are indeed price responsive, though the magnitude of response is generally found to be inelastic.[5] Industries with greater access to enabling technologies and self-generation are most responsive. Even with limited price response, for large users the magnitude of the savings can justify investments in AMI.

2.1 TOU

There are several early empirical studies that explore price responsiveness to TOU rates in comparison to flat rates and find small positive substitution effects (Chung and Aigner, 1981; Hirschberg and Aigner, 1983; Aigner and Hirschberg, 1985; Woo, 1985; Aigner et al., 1994). Chung and Aigner (1981) pioneered the studies estimating customer responses to TOU rates with Pacific Gas & Electric (PG&E) implementing mandatory TOU pricing in February 1977 for customers with demand above 4000 kW. Amongst the 64 aggregated customers across 13 C&I groups from October 1975 to February, they find TOU responses varies across industries likely driven by the industry's production process. Amongst industry groups in manufacturing, demand fell by 0.05% to 0.2% in response to a 1% increase in peak period prices.[6] Industry groups that relied on continuous processes and for process heat exhibited smaller responses whereas industry groups engaged in mechanical processes were most responsive, albeit still relatively inelastic. Overall, TOU pricing did not cause a shift in electricity demand across periods.[7]

[5] "Inelastic" is an economic term used to describe when the quantity of demand is less than unit responsive to a change in price (i.e. a 1% increase in the price leads to a less than 1% decrease in demand).

[6] The corresponding own-price elasticity, a measure of sensitivity to same-period prices, ranged from -0.05 to -0.227.

[7] Cross-price elasticities capture changes in demand in a given period in response to price changes in another period. Most cross-price elasticity estimates were not statistically significant from zero. However, for industry groups with significant cross-price elasticities (these groups were also those with large own-price elasticities), electricity consumption was shown to be substitutable across different periods of the day.

Hirschberg and Aigner (1983) build upon Chung and Aigner's (1983) econometric framework to examine mandatory TOU rates implemented by Southern California Edison (SCE) in October 1977 for large customers (demand exceeding 5,000 kW). Based on a sample of 104 C&I customers across 19 SIC groups from 1976 to 1980, they find across all industry groups, an up to -0.035 own-price elasticity for the winter peak, meaning that a 1% increase in the peak price induced a 0.035% reduction in electricity demand in the same period. Their cross-price elasticity estimates differ from the Chung and Aigner (1983) where depending on the season, demand in different periods may be complements or substitutes.

In a TOU pricing experiment involving 700 small and medium size firms serviced by SCE between 1980 and 1982, Aigner and Hirschberg (1985) find that a time-varying demand charge (coupled with a flat energy charge) was more effective than a time-varying energy charge (coupled with a time-insensitive demand charge) in inducing substitution between peak and off-peak periods. Large demand customers (200-500 kW) under the TOU demand rate switched usage from peak to off-peak periods by 11% for every 1% increase in relative price (between peak and off-peak times) during the summer.[8] Assuming a 2.5 to 1 ratio of peak to off-peak demand, this corresponded to a 1% gain in welfare, which means savings for the average customer in the first year outweighed additional metering costs.[9]

In another TOU experiment conducted in California in 1982 on 560 nonresidential Pacific Gas and Electric (PG&E) customers with billing demand less than 500 kW, Woo (1985) finds small responses to TOU prices; for a 1% increase in peak time prices, there was a 0.01 to 0.03% decrease in peak consumption. Woo also finds that electricity use in different time periods are substitutes, as evidenced by positive cross-price elasticities. Similarly, in a randomized control trial in Israel with 460 medium C&I customers in 1992, Aigner et al. (1994) find small shifts in electricity usage between peak and off-peak periods, though sensitivity to prices vary across seasons and industrial groups (rather than customer size).[10] Even the small amount of load-shifting, however, justified investments in metering technology.

These earlier findings are validated by more recent studies of programs in California and Korea (Faruqui and George, 2005; George et al., 2012; Jang et al., 2015). Using a demand model based on California's Statewide Pricing Pilot[11] during the summers of 2003 and 2004, Faruqui and George (2005) find small and medium C&I customers (under 200 kW) of California's three investor owned utilities (IOUs) reduced energy consumption during the peak period in response to TOU rates and CPP.[12] The CPP tariff which includes a variable peak period on critical days and day-ahead notification, was implemented for two groups of customers—one selected from the general population and the other from a pre-existing

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[8] The corresponding constant elasticity of substitution (CES) is 0.1131. This is a measure of the sensitivity to relative prices across periods. Across all customers overall, the CES is 0.04433.

[9] Given the estimated average monthly bill, a 1.1% welfare gain amounts to $79, and over the six summer months, totals $475.

[10] Own-price elasticities for the peak period ranged from -0.054 to -0.079 during the winter, and -0.004 to -0.007 in the spring/autumn, and no estimated response in the summer.

[11] These include PG&E, SCE, and San Diego Gas & Electric (SDG&E).

[12] The study presents estimates on the TOU rates, but due to the small sample size and variation in model coefficients across the individual years, the authors instead focus on the CPP models.

smart thermostat pilot. Whereas the latter group had both central air conditioning and smart thermostats, most customers in the former group had central air conditioning and roughly half opted for smart thermostats. For the general population customers, energy use fell by roughly 6% (peak demands less than 20 kW) and 9% (peak demands between 20 and 200 kW), on these critical weekdays in 2004. Meanwhile, customers that also had enabling technology—the smart thermostat pilot group—were able to achieve a 14% reduction.

George et al. (2013) evaluated California's CPP program for C&I customers in 2011. Under the rate design guidelines for time varying pricing set by the California Public Utilities Commission in 2009, the three IOUs offered CPP as the default tariff with bill protection in the first year; if customers chose to opt-out, they fell into another time varying rate (meaning there was no flat rate option). The default CPP price reflected the marginal cost plus the capacity cost of meeting peak loads. Other details such as which customers were subject to the default tariff, the timing of implementation, opt-out rules, event hours, notification, and rates varied by utility. George et al. (2013) find peak demand amongst 6,000 customers of the three IOUs fell on average by nearly 6% on CPP event days compared to baseline loads. The largest aggregate load impacts came from three categories of industry groups—agricultural, mining, and construction; wholesale, transport and other utilities; and manufacturing—which together were responsible for 60-90% of the program impact.[13]

Similarly, Jang et al. (2015) find industrial businesses to be more price responsive than commercial businesses. They estimated hourly customer base loads for 802 customers across 34 C&I business categories in a CPP pricing pilot program conducted in Korea during the winter of 2013. They found that commercial customers reduced their peak load by 8% on average, and industrial customers by 16%. Their firm-level analysis revealed large differences in demand response both across and within business categories. For instance, within the industrial sector, metals, chemicals, rubber and plastics, wood, paper, and waste treatment – are highly responsive while ore mining, electronic equipment, other transport equipment, and water supply had little to no response. The magnitude of demand response is also positively correlated with share of total expenditures spent on electricity. Lastly, the authors find that several business categories in the industrial sector – manufacturing and sewage – experienced a "learning" effect, where demand response increased with the number of CPP events.

Jessoe and Rapson (2015) find negligible changes in overall and peak usage as a result of a mandatory TOU program for 1,785 C&I customers in Connecticut between January 2009 and August 2011. The price differentials were however much lower in comparison to other studies, and reinforce the importance of peak to off-peak price ratios in inducing peak load reductions (Faruqui and George, 2005; Aigner and Hirschberg, 1985). The program implemented an on- and off-peak energy charge coupled with a lower, yet still time-invariant, demand charge. While these two effects in theory could counteract one another, the energy charge tended to dominate the overall bill. However, the finding that there was an overall

[13] This is based on results from SCE and PG&E which has roughly 3,000 customers and 12 event days, and 1,750 customers and 9 event days, respectively. SDG&E experienced 2 event days and find in aggregate, offices, hotels, finance and services comprised 30% of the program impact, in line with that of wholesale, transport, and other utilities.

reduction in the average electricity bill by 2% was largely driven by the lower demand charge rather than measurable behavioral change.

2.2 RTP

As documented in the majority of the TOU literature, customers indeed respond to RTP signals, but only some respond substantially. These customers tend to drive the magnitude and significance of the average responses (Zarnikau, 1990; Heriges et al., 1993; Patrick and Wolack, 2001; Schwarz et al., 2002; Taylor et al., 2005; Braithwait and O'Sheasy, 2002; Hopper et al., 2006ab; Choi et al., 2011). Industries and businesses with more flexible production processes and/or the ability to self-generate are more responsive (Zarnikau, 1990; Patrick and Wolack, 2001; Braithwait and O'Sheasy, 2002; Schwarz et al., 2002; Taylor et al., 2005; Hopper et al., 2006ab). Similar to the TOU literature, studies find that the price differential between times of the day has to be substantially large to induce behavioral change (Braithwait and O'Sheasy, 2002; Schwarz et al., 2002; Boisvert et al., 2004). In addition, studies suggest that there is a learning effect over time. Schwartz et al. (2002) and Taylor et al. (2005) find that the magnitude of customer response increases with experience.

Early work by Zarnikau (1990) examined customer responsiveness of 16 large industrial customers in Texas who opted into Houston Lighting and Power Company's RTP rate in 1986. These firms purchased some of their energy under the traditional firm rate and then notified the utility of the quantity they wished to purchase at the hourly marginal cost a day prior. Customers reduced electricity usage the most between 4 – 8pm, when prices were highest. Zarnikau also finds that on average customers reduced their hourly consumption by 0.09% for every 1% increase in that hour's price.[14] The author suggests that customer response to hourly prices may have been limited by both small price differentials between periods and insufficient price signals, as hourly prices were not known until the end of each month when rates were computed based on model simulations of system operations.

Herriges et al. (1993) was the first of several studies to estimate price responsiveness of industrial customers of Niagara Mohawk Power Corporation (NMPC) in New York. In the RTP experiment, customers were charged the marginal cost of generation in each hour plus a fixed charge independent of sales volume. In response, some firms shifted their usage patterns, particularly at the hour of system peak. These results were driven by two customer types—stone/glass/clay products and transportation equipment. They find that a 1% increase in the relative price between hours lead to a change in consumption of 0.09%.[15]

Patrick and Wolack (2001) have similar findings for customer responsiveness to half-hourly RTP for C&I customers in the England and Wales between 1991 to 1995.[16] Across the 5 British Industrial Classification (BIC) industries selected—water supply, steel tubes, copper/brass/other copper alloys, ceramic goods, and hand tools/finished metal goods—water supply was the most price-responsive industry, where a 1% increase in the hourly price

[14] The average own-price elasticity was -0.09.
[15] Using a nested CES function, they obtain intraday and interday elasticities of 0.093 and 0.163, respectively, across the eight test months.
[16] Customers also pay a demand charge (referred to as a triad charge) for the half-hours coinciding with the three highest system peak loads for each fiscal year.

of electricity leads up to a 0.27% reduction in water usage during that hour (outside of the 2:30 – 6pm peak period). Steel tubes had the smallest response, which was an expected result given the production processes in these industries.[17]

Hopper et al. (2006ab) and Boisvert et al. (2007) later examined the price response of 119 customers with peak demand greater than 2 MW during the summers of 2000 and 2004 under NMPC's default RTP program. Hourly day-ahead prices were tied to the New York Independent System Operator's (NYISO) locational marginal prices which reflect the value of energy (including ancillary services and the use of transmission system) by geographic location. They find that for every 1% increase in relative hourly prices, there is a 0.11% shift away in relative load.[18] Manufacturing had the highest sensitivity to relative price changes, followed by the government/education sector.[19] Other sectors—commercial/retail, health care and public works—were about half as price sensitive.[20]

Evidence from Georgia Power's RTP program[21] also shows how responsiveness to prices varies among customers and across a range of price levels. In Georgia Power's two-part tariff, hourly prices—announced on a day-ahead or hour-ahead basis—are applied to variations between actual consumption and customer baseline loads (CBLs). Braithwait and O'Sheasy (2002) find that large industrial customers facing hour-ahead RTP prices were the most price-responsive, with own-price elasticities ranging from 0.18 (at the lowest price level) to 0.27 (at the highest price level). Of the remaining customers on day-ahead prices, customers with on-site generation and industrial customers that were previously on an interruptible tariff were the next most responsive groups, with own-price elasticities ranging from 0.06 to 0.13. In contrast, C&I customers on non-interruptible tariffs were the least price-responsive, and at prices below $0.25/kWh, had an own-price elasticity in the range of 0.01 to 0.03.

Schwarz et al. (2002) focus on 110 Duke Energy industrial customers in 20 industries during the summers of 1994-1999. They find customers that self-generate or have discrete (batch) production processes are the most responsive to price signals. Overall, summer peak demand fell by 8% as a result of RTP.[22] Schwarz et al. (2002) find evidence of a threshold effect, where customers only respond significantly above a certain price level. Based on the same sample of industrial customers under Duke Energy's optional RTP rates, Taylor et al. (2005) find customers with generators and arc furnaces are highly responsive.[23]

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[17] Whereas water supply has the ability to shift their pumping schedule (typically carried out once or twice a day) to low-cost hours with short notice, steel tubes production is a continuous process due to the start-up costs of running machinery and required labor (Patrick and Wolack, 2001).

[18] The load-weighted average substitution elasticity under hourly prices was 0.11.

[19] Manufacturing's substitution elasticity was 0.16 and government/education was 0.10.

[20] They all had substitution elasticities under 0.06.

[21] Georgia Power is the most widely referenced RTP program, which began as an optional pilot program in 1993 (Braithwait and O'Sheasy, 2002; Braithwait and Eaki, 2002).

[22] In aggregate, they estimate an hourly substitution elasticity of 0.04.

[23] Aggregate own-price elasticities are highest during the system peak (2 – 9pm) in the summer, reaching as high as -0.26 at 2pm. Overall, adjacent hours have negative cross-price elasticities indicating complementarity while more distant hours are positive, and therefore regarded as substitutes. This finding dismisses concern over a shifting peak under day-ahead RTP as loads around high-priced hours also fall.

Boisvert et al. (2004) likewise find customer response amongst 54 customers on Central and Southwest Service's (Oklahoma) optional RTP tariff in the summer of 1998 to 2001 varied by class and to price. The two-part revenue-neutral RTP tariff was applied to the difference between a customer's CBL and actual usage, akin to that of Georgia Power. They find that, on average, a 1% increase in relative hourly prices lead to a 0.1- 0.18% decrease in the relative electricity load during those hours. However, sensitivity to prices varied with the level of relative prices as well as the duration of high-priced hours. This is also true for customers who opted for RTP with load reduction (received option payment annually for pledged load reduction and the utility could exercise a $0.38 RTP price under certain conditions). In terms of load-shifting behavior versus conservation, Boisvert et al. (2004) find over three-fourths of customer response was attributable to load shifting from peak to off-peak periods rather than conservation.

Lastly, in Ontario, Canada, Choi et al. (2011) find for industrial customers in the wholesale market for the summers of 2005 – 2008 that, on average, customers shift loads between hours by 0.02 to 0.07% in response to a 1% increase in the relative price of those hours.

2.3 Welfare Impacts

Overall, studies suggest that the net benefit of time varying pricing—that is, bill savings from demand during times of high cost supply—can outweigh the additional metering, communication, and administrative costs (Taylor et al., 2005; Borenstein, 2005b). With advanced infrastructure, the efficiency gains of RTP over flat rates and TOU are well-documented within empirical and simulation models (Taylor et al., 2005; Borenstein, 2005b). Taylor et al. (2005) find RTP yields a net benefit of nearly $14 million compared to Duke Energy's TOU rate for industrial customers. This translates to roughly $14,000 per customer per month, or 4% of monthly bills. Using hourly data from the California Independent System Operator from 1999 to 2003 in combination with a range of assumptions around customer price sensitivity, Borenstein (2005b) also finds TOU pricing captures at most 20% of the efficiency gains of RTP. RTP, even with very low price response (an own-price elasticity of -0.025), yields a surplus on the order of $100 million per year. This is in contrast to the $35 million allocated as a one-time cost to install RTP meters for its largest users (comprising nearly one-third of total demand) in California in 2001.

However, while increasing the number of customers on RTP likewise increases overall efficiency, the expansion of RTP to the remaining smaller customers leads to declining marginal surplus gains for existing RTP customers (Borenstein, 2005b; Borenstein and Holland, 2005). When only the largest customers are enrolled in RTP, the resulting net gains are more than twice that of when all customers face RTP (Borenstein and Holland, 2005). Moreover, installing meters for the remaining two-thirds of smaller customers may not necessarily pencil out from a benefit-cost standpoint.

The distributional effects of moving to either a mandatory or voluntary RTP largely remain a political barrier to implementation. Under flat rates, customers who consume large quantities of electricity during the system peak are subsidized by others who consume less at these high-priced hours. RTP dissolves this cross-subsidization. Borenstein (2007a) measures the potential wealth transfers under RTP using hourly customer-level usage data for 1,142 large

C&I customers of PG&E between 2000 and 2003. Assuming existing usage patterns are constant (i.e. customers do not respond to prices), RTP increases customer bills by 4 to 8% (75th percentile) compared to a flat rate, depending on the assumed scenario – around "very volatile," "less volatile," and actual wholesale prices. This translates to an increase of $107,000 to $151,000 dollars per customer over the 4 years. Borenstein (2007a) notes however that the magnitude is likely smaller given that most large customers are already on TOU rates. Therefore, when switching from a TOU tariff (with small price differentials between periods) to RTP under "very volatile" and "less volatile" wholesale prices, total wealth transfers are 36% to 45% smaller, respectively, compared to moving from a flat rate to RTP. For the average customer that switches from TOU to RTP, their bill would increase by roughly $81,000 to $134,000 over 4 years.

Even when accounting for price responsiveness, however, the adoption of time varying pricing will mean that some customers will endure a net loss even if there is an aggregate gain. Borenstein (2007a) notes that price responsiveness does not fully address the lost cross-subsidy for customers with more costly demand profiles and demonstrates a "two-part" RTP program—similar to that of Georgia Power's—that allows customers to purchase a baseline quantity at the regulated TOU rate. He finds it can reduce wealth transfers by 58%. In a separate study, Borenstein (2007b) further addresses the issue of bill volatility and find that forward price contracts for fixed quantities, which are already embedded in some RTP programs, can reduce up to 80% of the bill volatility under RTP.

3. C&I Rates in Hawaii

This section reviews for illustration current rate schedules for HECO C&I customers on Oahu. C&I customers fall under Schedule G (small power users), Schedule J (medium power users), Schedule P (large power users), and Schedule DS (large power users served directly by a substation). Most C&I customers fall under the first three, while Schedule DS is limited to the military, University of Hawaii at Manoa, and other large users that are served directly by a substation. Table 1 below illustrates the most current (2011 rate case) flat rate schedules in effect for Oahu.[24] There are three main components: a customer charge, demand charge and energy charge. The demand and customer charges vary by customer class and are in principle intended to capture the fixed costs of operating and maintaining the grid, though clearly in practice there is mixing into the retail volumetric rate. The demand charge, assessed on all kW for customers on Schedule J, P, and DS is based on the greater of the peak demand for the current month or the average of the peak demand for the current month and the highest peak demand for the last eleven months. This rate structure implies that a customer's demand charge can increase more rapidly than it can fall. If the prior month's peak usage is highest, for example, the demand charge will immediately rise. However, it may take nearly a year to "erase" that month's usage from the calculation of the demand charge, assuming no new peak is set.

[24] A final decision and order on HECO's 2016 rate case was issued on June 22, 2018. Final tariff sheets are to be submitted for review and approval (PUC, 2018b).

The energy charge varies across the four schedules and is adjusted monthly according to fuel costs through the energy cost adjustment clause (ECAC). Amongst the three primary schedules for C&I customers, Schedule G has the highest energy charge but does not incur a demand charge, while Schedule P has the lowest energy charge but faces the highest demand charge.

Table 1. Oahu C&I Flat Rate Monthly Bill Components

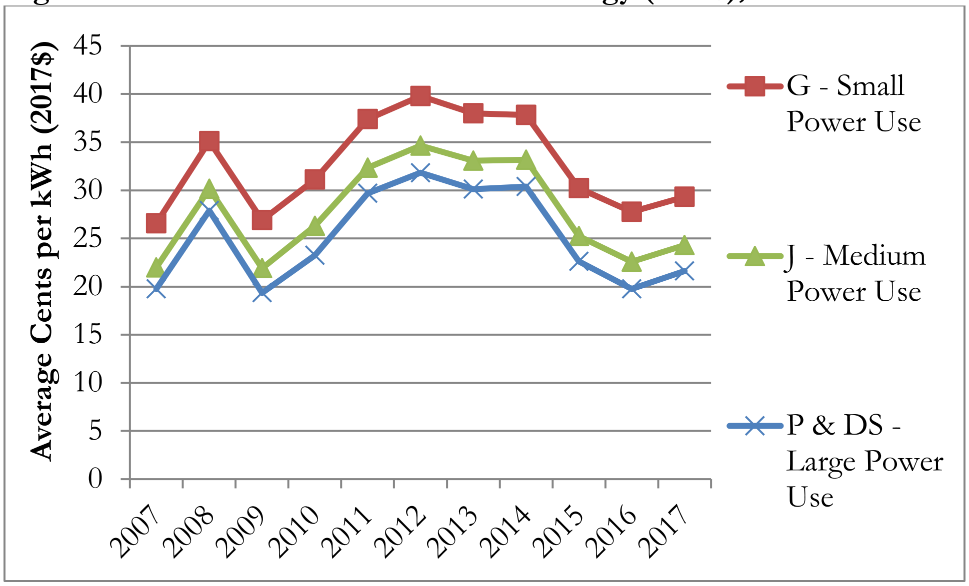
	G *General Service Non-Demand*	**J** *General Service Demand*	**P** *Large Power Service*	**DS** *Large Power Directly Served Service*
	< 5000 kWh/mo & < 25 kW/mo	*>5000 kWh/mo or 300>kW/mo >25*	*>300 kW/mo*	*>300 kW/mo*
Customer Charge ($)				
Single-Phase	$33	$60	-	-
Three-Phase	$61	$82	$350	$400
Demand Charge ($/kW)	-	$11.69	$24.34	$21.00
Energy Charge (¢/kWh)	$21.3317	$16.9734	$14.9013	$13.9223
	Adjustments			
ECAC (¢/kWh)	Updated monthly and the same for all customer classes			
PPAC (¢/kWh)	Updated monthly and varies across customer classes			
RBA Rate Adjustment (¢/kWh)[a]	$1.0350			
	Surcharges and Fees			
PBF Surcharge (¢/kWh)[b]	$0.2243			
Green Infrastructure Fee ($/month)[c]	$1.31	$23.03	$442.94	$442.94

[a] Effective January 1, 2018.
[b] Effective July 1, 2018 to June 30, 2019.
[c] Effective July 1, 2018 to December 31, 2018.
Source: HECO, 2018b.

The final bills paid by customers reflect adjustments, surcharges and fees that vary either monthly, semiannually, or annually. The ECAC passes through monthly variations in fuel and purchased power cost from the energy charge. The Power Purchase Adjustment Clause (PPAC) which similarly varies monthly, recovers capacity, operation and maintenance, and other non-energy costs. The Revenue Balancing Account (RBA) rate adjustment is related to "decoupling," a rate-making method which delinks electricity sales from utility revenue. The Public Benefits Fund (PBF) surcharge supports energy efficiency programs administered by a third-party (Hawaii Energy). Finally, the Green Infrastructure Fee (GIF) supports the Green Energy Market Securitization (GEMS) program which was developed to provide loans to facilitate access to clean energy technology adoption by underserved customers.

Summing the final rates for the three main bill components approved in the 2011 rate case plus adjustments presented in Table 1, Figure 1 below shows the historical cost of final delivered energy for Schedules G, J, and P (HECO, 2018c).[25] The average rate paid by the largest customers (Schedule P and DS) is lower than that paid by smaller and medium customers.

Figure 1. Oahu Cost of Final Delivered Energy (2017$), 2007-2017

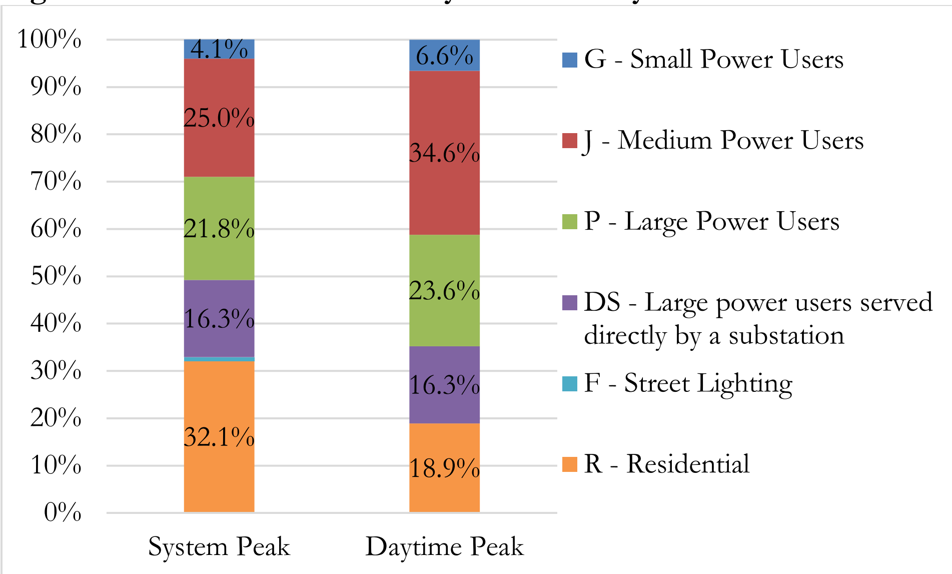


Source: HECO, 2018c.

Of these four C&I schedules, Schedule J contributes the most to the system peak and daytime peak based on the instantaneous peak in HECO's 2012-2013 Class Load Study (HECO, 2017). Collectively, the C&I schedules account for 67% and 81% of the system and daytime peak, respectively. Notably, residential customers are the largest contributor to system peak.

[25] Note, the cost of final delivered energy also includes Integrated Resource Planning (IRP) and demand-side management (DSM) cost recovery provision which allows the utility to recover its long-term planning process costs as well as certain DSM programs and the Renewable Energy Infrastructure Cost Recovery Provision (REIP), which allows the utility to recover the cost of certain projects that further renewable energy integration. Both of these surcharges are currently set at zero (HECO, 2018b).

Figure 2. Class Contribution to System and Daytime Peak



Source: HECO, 2017.

HECO also offers TOU rates for each of the three commercial customer classes (HECO, 2018b). Similar to experiences elsewhere, uptake is low. In 2016, 26 out of approximately 33,300 C&I customers on Oahu were enrolled in TOU rates (EIA, 2017b; DBEDT, 2017). Table 2 shows the TOU rate offerings for C&I customers. Demand charges for TOU-J and U vary by period and are assessed on the all kW in each block.

Table 2. Oahu C&I TOU Primary Bill Components

	TOU-G *Small Commercial TOU*	**TOU-J** *Commercial TOU*	**U** *TOU service*
	< 5000 kWh/mo & < 25 kW/mo	*>5000 kWh/mo or >25 kW/mo*	*>300 kW/mo*
Customer Charge ($)			
Single-Phase	$33	$60	-
Three-Phase	$61	$82	$350
Demand Charge ($/kW)			
Priority Peak (M-F: 5-9pm)	-	$18.69	$28.34
Mid-Peak (M-F: 7am-5pm, Sat-Sun: 7am-9pm)	-	$11.69	$25.34
Energy Charge (¢/kWh)			
Priority Peak (M-F: 5-9pm)	$26.3317	$21.9734	-
Mid- Peak (M-F: 7am-5pm, Sat-Sun: 7am-9pm)	$23.3317	$18.9734	-
On-Peak (7am-9pm, daily)	-	-	$16.9013
Off-Peak (9pm-7am, daily)	$18.3317	$16.0000	$16.0000

Source: HECO, 2018b.

Within the TOU rate schedules, weekday energy charge differentials between the on and off-peak are $0.03/kWh, about an approximate 10% change. Within the estimates of load-shifting in other studies, applying an own-price elasticity parameter of 0.2 that is on the higher end of sensitivity estimates reviewed, a 10% increase in on-peak prices would lead to a 2% reduction in on-peak demand. Though these price differentials are likely not large enough to create a substantial amount of load-shifting, this is likely a second order problem next to customer adoption of time varying programs.

In addition to TOU rates, there are several existing "rider" options for that have time varying elements. These riders are for medium to large users and are paired with flat rate schedules. Rider I is an interruptible service contract that allows the utility to disconnect 100 kW or more under specified conditions for no less than 5 years. In exchange, customers incur a lower demand charge. Though originally designed to address emergency events and system reliability (Capers et al., 2010), interruptible tariffs function as a "crude" form of RTP (Borenstein, 2005a). Though Rider I was closed to new customers in 2011, there may be existing customers still on this schedule (HECO, 2018b).

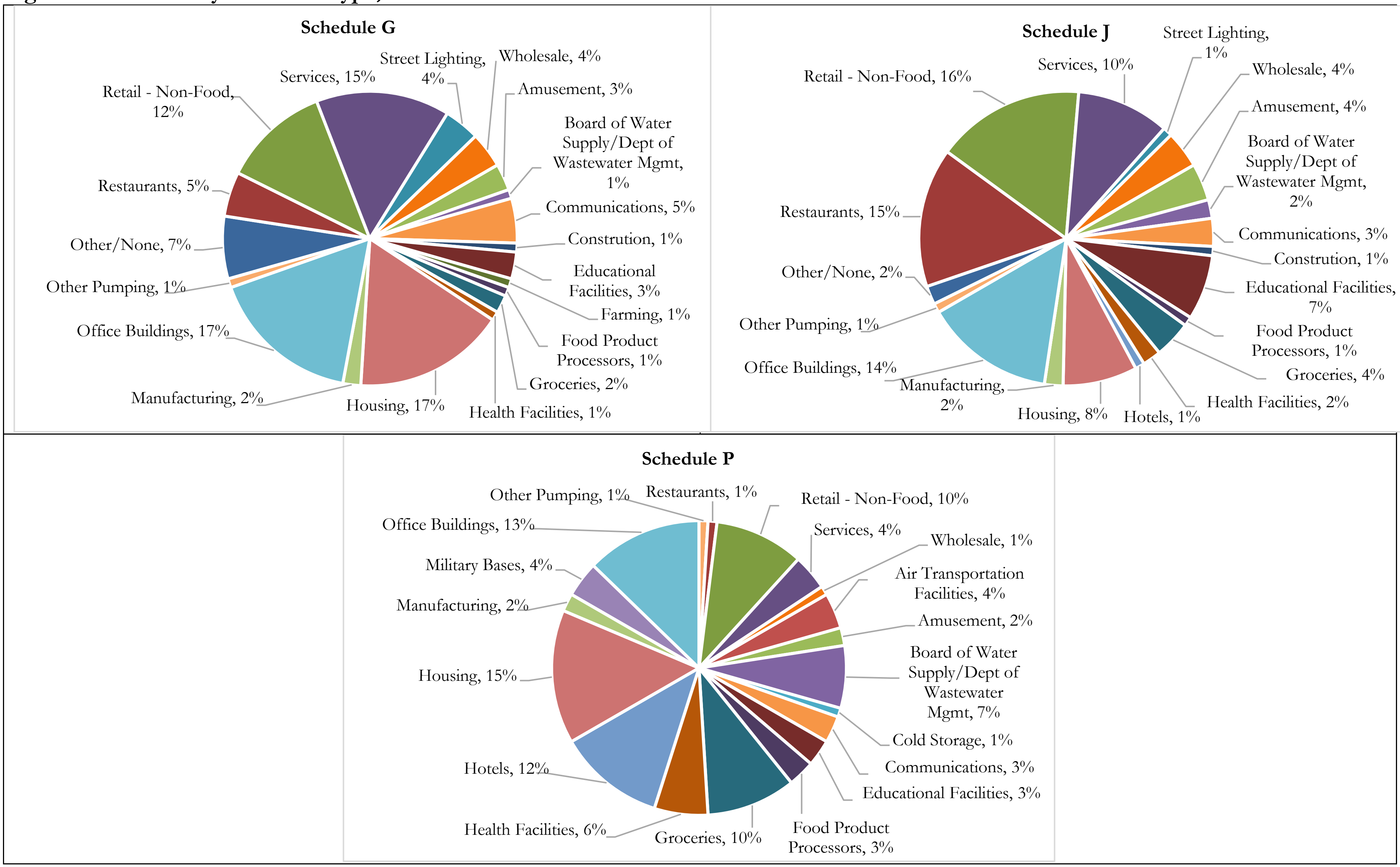
Rider M offers customers one of two options. Under the first, demand during the off-peak period, in this case between 9pm and 7am, does not contribute to establishing the demand charge. This construction of on- and off-peak is a dated representation of the generation, as now midday hours should likely be considered off-peak as well due to high penetration of solar PV. However, there is still a charge based on off-peak usage if the maximum off-peak demand exceeds the maximum on-peak demand. A $2/kW charge is then added to the regular rate. Thus, even though the nighttime consumption of electricity does not set the overall demand charge level, it can still influence it. Under the second option, customers specify the load they are willing to curtail during periods established by HECO, where the actual amount curtailed is estimated based on the difference between the maximum kW demand in times outside of the curtailment period and within the curtailment period. The bill then adjusts for the amount curtailed by the customer, by a range of 40-75% of the value of the amount curtailed.

Lastly, Rider T (time-of-day rider) adjusts the energy charge for rate schedule J, P, and DS upwards during the daytime peak period (7am to 9pm) by 2 cents/kWh, and downwards by 3 cents/kWh during all other hours. Again, this no longer reflects the current temporal dynamic of current system costs.

To provide some perspective on the distribution and types of customers on each rate schedule, Figure 3 illustrates the composition of end-use customers based on the number of accounts on Schedules G, J, and P.[26] The data comes from HECO's 2008 Class Load Study, submitted in their rate case for the 2011 test year (HECO, 2011). Though there is an updated 2012-2013 Class Load Study filed as part of HECO's rate case for the 2017 test year, a similar breakout of business types on each rate schedule is not provided.

[26] Figure excludes business types that are reported as 0% under each schedule.

Figure 3. Accounts by Business Type, 2008[27]



Source: HECO, 2011.

[27] May not sum to 100% due to rounding.

Figure 3 shows that some business types fall under all three C&I rates schedules, and others are concentrated on a particular rate schedule. While retail, housing (multi-family), and office buildings are the leading business types in terms of the number of customer accounts on each of the three rate schedules, military bases[28] and hotels predominantly fall under rate schedule for the largest users (Schedule P). Note that, as presented in the Class Load Study, with the exception of business segments that fall under a single rate schedule, the overall density of business types cannot necessarily be inferred as the share of each business type is relative to the number of accounts on each rate schedule.

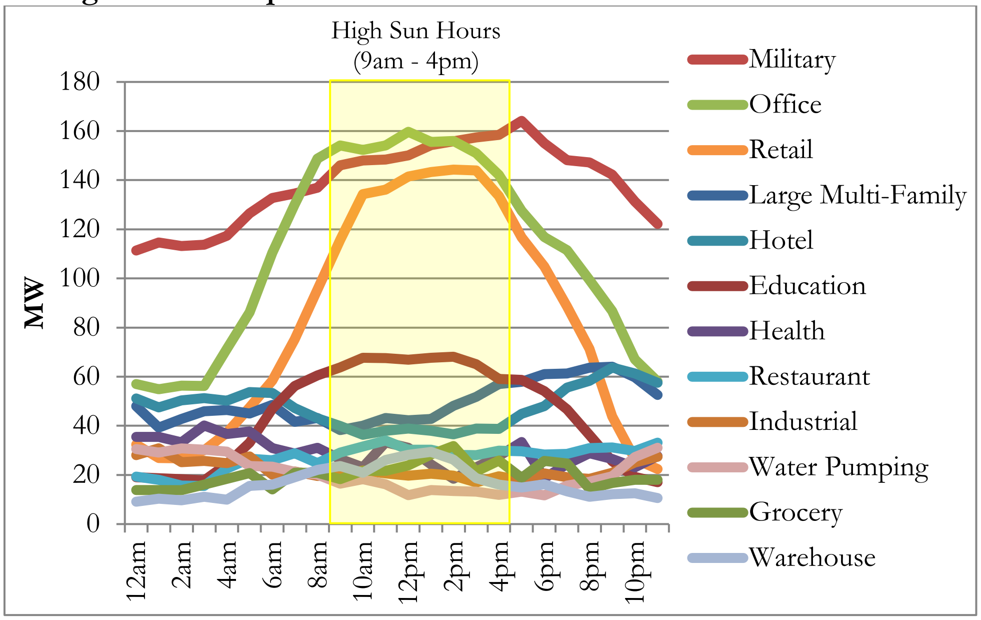
4. Hawaii C&I Load Curves by End-Use

We present baseline electricity demand profiles for twelve C&I customer types on Oahu to show trends for a variety of economic sectors and provide discussion on the potential impacts to the sectors (in the aggregate) of time varying pricing. This data is publicly available within a study published by Navigant Consulting (2015) and filed electronically within the demand response regulatory proceeding. To extract the data at the sector level, we used a software program, Graphclick, to estimate values based on published figures. [29] This allows us to more explicitly extract the shape of gross load curves by sector, which are provided for four representative months to show seasonality (February, May, August and November) in 2014. The gross load profiles are summarized in Figure 4, ordered from the largest to smallest users. The three largest consumers of electricity on Oahu are military, office, and retail. Other notably large consumers are hotels and education. For illustrative purposes, high sun hours are also marked within Figure 4. The temporal availability of high wind resources is clearly more difficult to identify, though equally important as a renewable energy resource that might be more effectively integrated with RTP.

[28] The military is included under "P" in the 2008 CLS as Schedule "DS" became effective June 20, 2008 (HECO, 2011).

[29] Therefore, values used in our analysis are subject to estimation error. However, their overall shapes are captured for the purpose of qualitative analysis.

Figure 4. Hawaii C&I End-Use Sector Gross Load Profiles
Average of Four Representative Months in 2014



Source: Navigant Consulting, 2015 and Graphclick.

The military is by far the largest consumer of electricity on Oahu. Its typical pattern of usage reflects that many of the activities are residential in nature, having lower load during the nighttime, early morning hours, and a peak around 6pm. Nonetheless this is inclusive of many different kinds of military activities other than residential housing. Because a substantial amount of the aggregate military sector's load is during the mid-day, largely because they are simply a large user, it is conceivable that they could be made better-off through pricing mechanisms that reflect the large availability of solar resources. However, military bases have themselves been proactive in pursuing solar resources. The impact of their peak usage, which coincides with system peak, largely depends on their ability to shift load with storage technologies.

The second largest consumer of electricity is "office," which has a bell-shaped pattern where electricity usage quickly rises in the morning, starting around 8am, and starts to decline in the afternoon hours. Though there is a high ramp and decline around workday hours, there is also a large amount of electricity consumed during the nighttime (hovering at about 60MW). Retail follows a similar bell-shaped pattern as office, though its peak usage hours are narrower and more directly relate to high-sun hours larger due to a later morning ramp-up. Interestingly, aggregate retail load is shown to decrease even in the evening and reaches its lowest levels (around 20MW) by 11pm. Education also follows a bell-shaped curve though it is substantially "flatter." Education ramps up usage around 7am with the opening of school and begins to decline after 4pm. Because the office, retail and education sectors all have their peak usage, at least in the aggregate, during high sun hours, it is conceivable that these sectors could be made better-off with time-varying pricing structures – without shifting any load. The actual rate structure would of course make this determination, but the shape of the load curve with a "hump" during sun hours makes this assertion plausible.

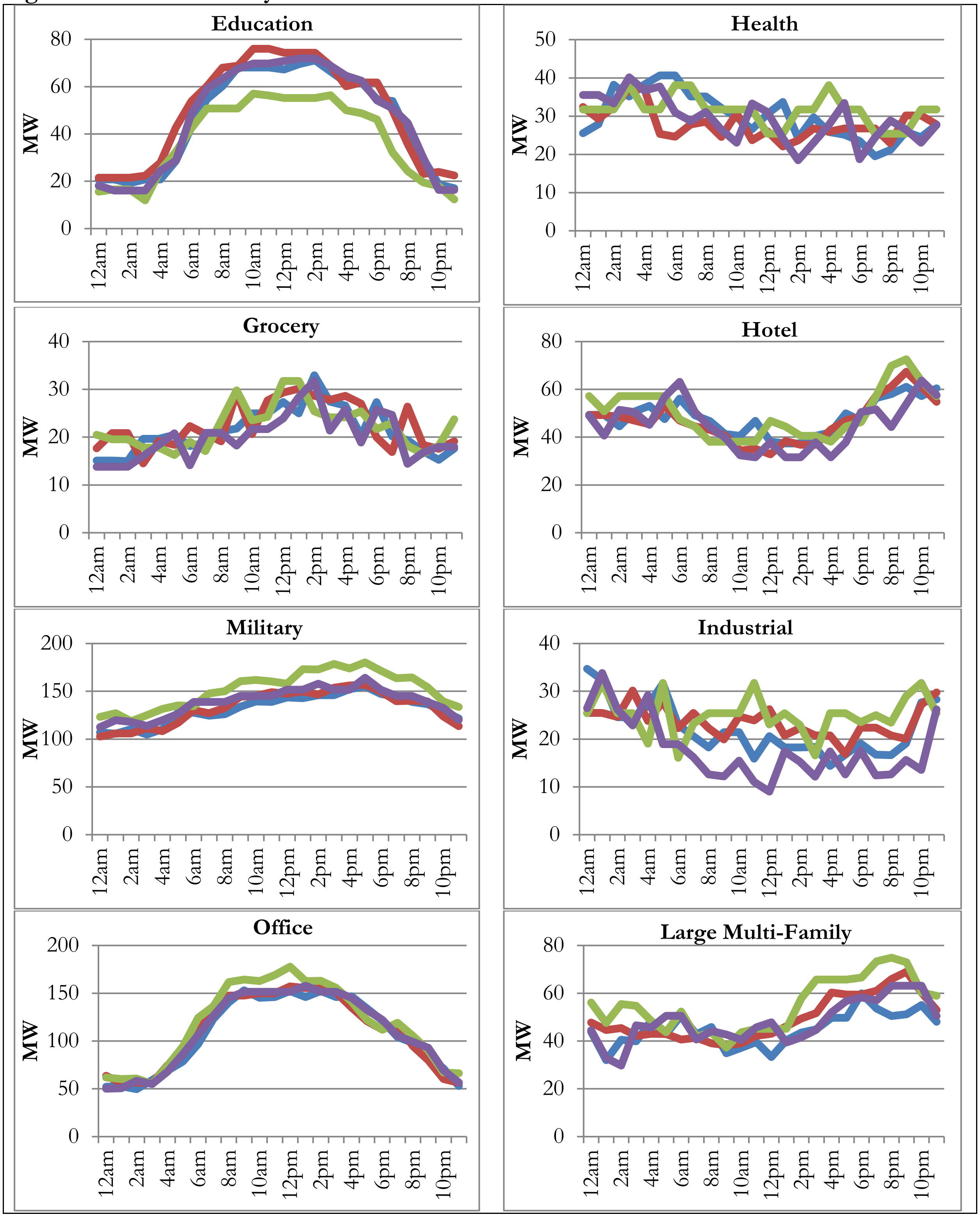
The hotel sector, on the other hand, experiences their lowest usage during high sun hours. Their peak is during the evening and usage stays high during the nighttime hours. This in many ways mimics residential usage patterns, except that nighttime consumption remains high. This is presumably due to activities like laundry services. It is unclear how the hotel industry would necessarily fare under time varying rates. To the extent that a significant share of its load in the peak could be pushed toward the day or even a substitution from nighttime to daytime load (e.g. laundry services), depending on relative rates, it is conceivable for the hotel industry to leverage benefits from a time varying rate structure. However as with other customer-facing sectors like retail, some of its load is based on consumer usage patterns for which they have limited influence.

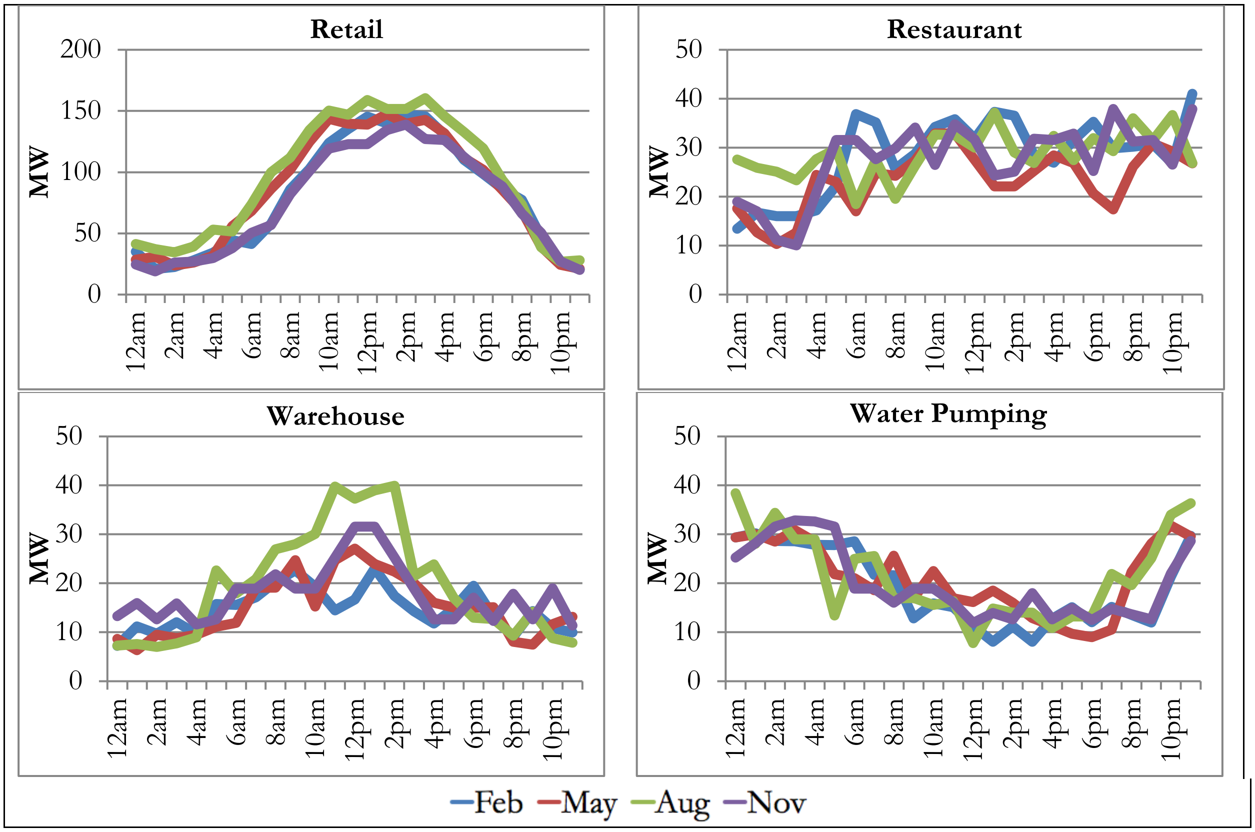
The health sector has a load that is relatively flat throughout the day and hovers between 30 and 40MW. Hopper et al. (2006ab) and Boisvert et al. (2007) unsurprisingly find that electricity consumption within healthcare is relatively unresponsive to price effects, with an average substitution elasticity of 0.04. Because healthcare is a critical service, however, hospitals and other critical units have substantial backup and self-generation power. As an example, Queens Hospital in Honolulu has on-site generation capacity of 9MW, which allows the hospital to operate for about a week (The Queen's Connection, 2010).

Water pumping is an interesting sector because it may be relatively more responsive than others, even though still inelastic. For instance, Patrick and Wolack (2001) estimated water supply to have an own-price elasticity as high as -0.27. Currently, the load from water pumping on Oahu is lowest between 12pm – 5pm. The size of existing water tanks and their rate of pumping are the main constraints to how much the water pumping sector can currently shift its load. For example, if all water tanks could store enough water for the peak day and fill their tanks in one hour, then every day, they could choose to fill their tanks to capacity during the hour of lowest electricity rates.

Though Hawaii is a tropical region, we still observe differing patterns of electricity usage based on the seasons. Trends in seasonality across the eleven C&I sectors documented by Navigant (2015) are shown in Figure 5. Because they have been captured in Graphclick, small fluctuations are likely subject to measurement error and should be interpreted with caution. However, overall trends should hold. The figures are separated by the large mid-day users on the left, and those with relatively flatter daily profiles on the right. Note that the scale of usage (in MW) is considerably different by sector.

Figure 5. Load Curves by End-Use for Four Months in 2014





Source: Navigant Consulting, 2015, and Graphclick.

With the sectors broken out individually, and by season, it is easier to identify trends in daily consumption patterns. Education, for example, has a lower consumption during August because school is not always in session. Other sectors, particularly office, retail and warehousing, tend to have higher loads in the summer, likely attributable to increased air conditioning use.

5. Conclusion

This study reviews literature on time-of-use and real-time electricity pricing programs and its effect on electricity usage within the commercial sector. Studies find mixed effects of the move from time invariant to time varying pricing programs. In general, customers are found to be price responsive though "inelastic," meaning that it takes a relatively large price change to get a relatively small amount of load-shifting. In addition, the literature emphasizes that price responsiveness varies at the individual level and only a few sectors are highly responsive. Even with inelastic price response in the aggregate, however, several studies concluded that the investment in additional metering technology within C&I customers was merited – that for large users, the additional metering cost is dwarfed in comparison to system benefits from load-shifting.

Within Oahu, our presentation of aggregate load curves for C&I sectors suggest that several industries are well poised to benefit from time varying rates – those with existing bell-shaped curves during high sun hours (education, office and retail sectors). C&I sectors on Oahu that can more flexibly shift their loads towards times of large electricity generation from either wind or solar energy, and those that can cost-effectively self-generate are also likely to benefit from a time varying rate structure. Moreover, by definition, the studies reviewed are considering time-of-day price differentials likely to be lower than those faced in Hawaii. Hawaii has the highest electricity rates within the U.S. as well as aggressive goals to integrate renewable energy – meaning that the differences between high and low-cost electricity provision is likely greater in Hawaii than other localities. This means that the opportunity for price responsiveness is also likely greater than the studies reviewed suggest. This leaves considerable room for optimism in the role of new pricing structures supported by AMI efforts to incent the integration of renewable energy resources.

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