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On The Benefits of Behind-the-Meter Rooftop Solar and Energy Storage: The Importance of Retail Rate Design

Richard Boampong
University of Alberta

David P. Brown
University of Alberta

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by

Richard Boampong[†] and David P. Brown[‡]

Abstract

We investigate the impact of retail rate design on the investment incentives, avoided utility costs, and cost-shifting concerns associated with rooftop solar and rooftop solar plus battery storage systems that are located behind-the-meter. We consider recently proposed changes to California's time-of-use pricing policy for commercial and industrial consumers which shifts on-peak prices from midday hours to the network constrained evening hours. We find that the shift in on-peak hours decreases investment in rooftop solar and has an ambiguous effect on storage investment. We demonstrate that storage reduces utility network costs, but the magnitude of this effect varies critically with the prevailing retail rate structure. Importantly, we show that a shift in the on-peak period to the constrained evening hours does not always elevate the avoided network cost associated with a battery system when demand charges are imposed on a consumer's private maximum demand. We illustrate that this issue can be alleviated by imposing demand charges on consumption that arises in system-constrained hours. We find that cost-shifting concerns are substantially reduced under the proposed rates and tariffs that have a heavy reliance on demand charges. We illustrate that while storage reduces the utility's costs, it can also increase cost-shifting concerns. These findings demonstrate the potential trade-offs between maximizing avoided costs and minimizing cost-shifting concerns under commonly employed retail rate structures.

Keywords: Retail Rates, Electricity, Regulation, Storage, Solar PV
JEL Codes: L40, L51, L94, Q48, Q58

† Department of Economics, University of Alberta, Edmonton, Alberta Canada (boampong@ualberta.ca).

‡ Department of Economics, University of Alberta, Edmonton, Alberta Canada (dpbrown@ualberta.ca).

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1 Introduction

Solar power has become an increasingly important source of energy in electricity markets worldwide due to declining costs, favorable policies, and concerns over greenhouse gas emissions. In particular, there has been increased interest in the deployment of rooftop solar panels located near the point of consumption. As of 2017, there is an estimated 16,224 MWs of rooftop solar in the United States (EIA, 2018). While solar power has numerous benefits, the rapid deployment of solar generation capacity has introduced several important complications.

First, solar output is high in the midday hours, but declines quickly as the sun sets. The resulting demand for electricity from the utility network exhibits low midday levels, followed by a steep ramp upward in the evening hours. In jurisdictions such as California with a high penetration of solar capacity, these dynamics have led to suppressed costs of providing energy services in the midday hours, but elevated cost in the constrained evening hours as natural gas peaker plants are called upon to meet demand (Bushnell and Novan, 2018).[1,2] Second, solar output is intermittent. This can have a large impact on the potential value of solar capacity (Gowrisankaran et al., 2016).

Third, as solar capacity grows, it is becoming increasingly common that solar generates more electricity than is needed during the day. This overgeneration leads regulators to curtail solar power to maintain an exact balance between supply and demand on the electricity network (CAISO, 2018). Fourth, there are growing concerns that utility revenues are declining faster than avoided costs decrease as rooftop solar is deployed (CPUC, 2013; Wolak, 2018). The primary driver for this concern arises from the design of regulated retail rates which consist largely of volumetric (per-unit) charges that recover both fixed and variable costs of utility operations.[3] As demand for electricity declines (e.g., due to the adoption of rooftop solar), volumetric prices increase in order to offset the lower utility revenues and ensure fixed-cost recovery. This issue raises concerns that costs will be shifted to non-rooftop solar consumers (hereon, referred to as cost-shifting).

In this paper, we investigate the interaction of two potential solutions to these challenges that involve redesigning retail rate tariffs and the deployment of distributed battery storage located near the point of consumption (behind-the-meter). Battery storage can be utilized to store energy during low demand hours or when there is overgeneration and discharge stored energy in system constrained hours or to bridge intermittency gaps. There has been increased interest in battery technologies due in large part to declining cost.[4] Several states have introduced ambitious targets to procure energy storage including California, New York, and New Jersey who aim to procure 1,300 MWs, 1,500 MWs, and 2,000 MWs of energy storage capacity respectively before 2030 (CPUC, 2013b; NYPSC, 2018; New Jersey Legislature, 2018). California's target includes 200 MWs of

[1] Recent research suggests that this net demand profile will develop in other jurisdictions (e.g., in Ontario Canada (IESO, 2017); New England (ISONE, 2018); and Texas and New York (Seel et al., 2018)).

[2] The growth in electric vehicles is expected to magnify the challenges caused by this demand profile (CEC, 2018).

[3] For example, in the United States, fixed costs reflect 40 - 65% of a residential consumers total monthly bill and the majority of these costs are recovered via volumetric charges (Wood et al., 2016).

[4] The cost of lithium-ion batteries declined by an average of 23% per year from 2010 to 2015 (Ardani et al., 2017).

behind-the-meter storage and subsidies allocated to distributed storage (CSE, 2017).

We empirically investigate the interaction between retail rate structures and avoided electricity network costs, cost-shifting concerns, and investment incentives in rooftop solar and distributed battery storage systems. Our analysis focuses on proposed changes to Southern California Edison's (SCE's) commercial and industrial (C&I) retail tariffs that include time-of-use (TOU) pricing, fixed charges, and maximum demand charges (MDCs) that charge consumers for their maximum amount of electricity purchased from the utility during a specified time period.[5] Existing tariffs include midday on-peak hours (12 PM - 6 PM), while the proposed tariffs shift the on-peak hours to the evening (4 PM - 9 PM) to better reflect the electricity network constraints and costs as the sun sets. Under both tariffs, demand charges are designed to target a consumers private maximum demands regardless of whether or not the electricity network is constrained in these hours. We also consider counterfactual tariffs that shift demand charges to reflect coincidental peak MDCs that charge consumers for their maximum demands in hours where the system is the most constrained.

We utilize smart meter consumption data from representative C&I consumers in Los Angeles California and an optimization algorithm called the Distributed Energy Resources Consumer Adoption Model (DER-CAM) to simulate the optimal operational decisions of behind-the-meter battery systems and investment decisions in rooftop solar and battery storage under various tariff structures. We utilize California's Avoided Cost Model (ACM) to measure the avoided costs associated with reduced consumption from the utility decomposed into avoided energy and capacity-related costs. The ACM captures hourly variation in the costs of providing electricity (E3, 2018).

We find large bill savings when consumers invest in rooftop solar under existing tariffs. The consumers' private value of rooftop solar declines substantially under the proposed tariffs when on-peak hours are shifted to the evening when solar output is relatively low. Consequently, solar investment declines under the proposed tariffs. Under both existing and proposed tariffs, the financial value of battery storage is driven largely by the incentive to avoid MDCs. We find that solar capacity investment can decrease when a consumer is able to also invest in battery storage because both technologies reduce MDCs in the early evening hours. While this is privately optimal from the consumers perspective, the level of avoided utility costs decrease.

We illustrate that changes in the tariffs have important impacts on battery charge and discharge decisions. Under the proposed tariffs, the shift in the on-peak period results in the battery being discharged later in the evening. However, the precise timing of the discharge decision depends critically on the features of the retail tariffs. When the retail tariffs consist primarily of volumetric charges, the battery is discharged to arbitrage on the peak to off-peak price differentials resulting in the battery being discharged in the early evening hours where the network is constrained. Alter-

[5] We focus on C&I consumers for two key reasons. First, it has been shown that battery systems are often profitable for C&I consumers and rooftop solar plus storage deployment is expected to quickly increase in this sector (Neubauer and Simpson, 2015). Second, C&I consumers face more complex retail tariffs that include fixed charges, time-varying volumetric rates, and MDCs. These rate design features are being debated as possible mandatory retail tariff components for all consumer groups (Hledik, 2014; NCCETC, 2017).

natively, when the retail tariff places a heavy weight on MDCs, on high demand days, consumers have an incentive to discharge the battery to avoid their private MDCs. This results in the battery being discharged in the late evening hours when the network is less constrained reducing avoided costs. The mismatch is alleviated when coincidental peak MDCs are imposed.

The avoided costs associated with rooftop solar arises primarily from reductions in energy-related costs. Adding energy storage elevates capacity-related avoided costs substantially, but this effect varies with the prevailing rate design. Somewhat surprisingly, avoided costs associated with a battery system can decrease under the proposed retail rates. When retail tariffs place a heavy weight on MDCs, the battery is used to avoid private peaks in demand. The shift in on-peak hours can reduce the avoided cost as the battery is discharged late in the evening to avoid private on-peak MDCs. Alternatively, when the tariff consists primarily of volumetric charges, the shift in the on-peak period better aligns storage discharge with system constraints. Imposing coincidental peak MDCs elevates avoided cost because the battery is discharged in network constrained hours. These findings demonstrate that a shift in the on-peak hour definition to better reflect system constraints may not strictly increase avoided costs associated with a rooftop solar and battery system when certain retail rate design features are adopted.

We find that the addition of rooftop solar has a minimal impact on a consumers' private maximum demand but can reduce its maximum demand during system constrained hours in the summer months that arise early in the evening. When coincidental peak MDCs are imposed, the addition of energy storage has a large impact on reducing consumers demands in system constrained hours. Otherwise, the battery is targeted to reduce private peaks in demand. This has important implications on the costs of operating the network as a large portion of capital investments remain idle for the vast majority of hours, only operating for a few hours a year to meet peak demand.[6]

We illustrate that existing tariffs yield substantial cost-shifting concerns that arise when the bill savings of a rooftop solar or a rooftop solar plus storage system exceeds the associated avoided cost. This effect is largest in retail tariffs with high volumetric rates paid to solar output, while it is mitigated when tariffs rely more heavily on MDCs for fixed-cost recovery. The shift in on-peak hours under the proposed tariffs alleviates these concerns substantially. While the presence of energy storage increases avoided costs, it also yields a higher cost-shifting measure. These findings demonstrate the potential trade-offs between maximizing avoided cost and minimizing cost-shifting concerns when regulators are restricted in their ability to set more granular time-varying retail prices that better approximate the costs of providing utility services.[7]

This paper proceeds as follows. Section 2 summarizes the related literature. Section 3 details the data used in our analysis. The empirical methodology is described in Section 4. Section 5

[6] For example, in Australia one distribution utility estimated that $11 billion in network capacity is utilized 4 or 5 days a year, while another estimated that nearly 20% of its capacity is utilized for 23 hours per year (ENA, 2014).

[7] It is generally believed that retail tariffs with increased time and location granularity can alleviate the mismatch between retail rates and avoided cost (MIT Energy, 2016; Biggar and Reeves, 2016). However, these tariffs have not received wide adoption in part due to the complexity of designing such cost-reflective tariffs (CPUC, 2017b).

presents our primary findings. Section 6 accounts for endogenous investment. Section 7 concludes.

2 Related Literature

Our research contributes to three recent strands of literature that investigates the interaction of retail rate design and the growing penetration of rooftop solar and distributed battery storage which are often referred to as Distributed Energy Resources (DERs). The first relates to a growing body of literature that establishes theoretical models to investigate retail rate design and DER compensation policies (Brown and Sappington, 2017a, 2017b, 2018; Gautier et al., 2018). This literature emphasizes the potential distortions that can arise due to inefficient retail rate design in the presence of DER investments. Further, this literature demonstrates that different retail rate design features can have important impacts on DER investment and the network value provided by DERs (e.g., Brown and Sappington (2017a) and Gautier et al. (2018)). This work complements recent analyses that call for increased time-varying and cost-reflective retail prices in the presence of growing DER penetration (e.g., MIT Energy, 2016; Jenkins and Perez-Arriaga, 2017).

A second literature analyzes the impacts of retail rate features on the profitability of investing in rooftop solar (e.g., McLaren et al., 2015; Darghouth et al., 2016; Borenstein, 2017). These studies demonstrate that the private economics of rooftop solar is highly sensitive to retail rate design. Several articles demonstrate the profitability of solar photovoltaics (PV) plus storage systems for C&I consumers and how the financial prospects of these systems are impacted by rate design (e.g., Neubauer and Simpson, 2015; Hanna et al., 2017; McLaren et al., 2018). The complementarity between variable solar output and controllable energy storage allows consumers to manage peak demand, lowering their MDCs which can reflect 30% - 70% of a consumer's bill (NREL, 2017).

A third literature empirically investigates the costs and benefits associated with rooftop solar. Cohen et al. (2016) and Cohen and Callaway (2016) demonstrate that the value of rooftop solar can vary considerably by location. There is a large array of articles that estimate the value of rooftop solar PV across the United States.[8] Several studies evaluate the potential for rooftop solar to induce cost-shifting to non-DER consumers due to inefficiently high solar compensation. This literature finds evidence of cost-shifting, but the magnitudes vary across studies (CPUC, 2013a; Barbose, 2017; Rhodium Group, 2017). In a recent study, Wolak (2018) provides evidence that increases in distribution network costs can be largely attributed to the growth in rooftop solar.

To the best of our knowledge, there are no studies that simultaneously model the link between retail rate design and: (i) their impact on investment and operational decisions of solar PV and battery storage systems; (ii) the resulting avoided electricity network costs; and (iii) the associated cost-shifting concerns. In particular, there has been limited research that illustrates the important linkages between retail rate design features, the operational decisions of battery systems, and its implications on avoided costs. We begin to fill this gap in the literature.

Finally, our analysis contributes to the ongoing policy debates surrounding retail rate design in

[8]See Denholm et al. (2014) and Taylor et al. (2015) for a review of this literature.

the presence of growing DER penetration. In the United States, nearly every state is undertaking actions to adjust their retail rate designs and DER compensation policies (NCCETC, 2017). Many of these proceedings involve discussions on mandatory time-of-use pricing, mitigating cost-shifting concerns, and/or imposing MDCs with numerous potential features on both residential and C&I consumers (CPUC, 2017a,b; NCCETC, 2017; Linvill et al., 2017). While there is substantial debate over the design of retail rates, there is limited formal modeling that simultaneously investigates the impacts of these proposed rates on the financial value, avoided costs, and cost-shifting concerns associated with behind-the-meter solar PV plus storage systems. We address each of these components in our analysis.

3 Data

We leverage several data sets to carry out our empirical analysis. First, in order to establish representative load data, we use hourly smart meter demand data of commercial and industrial consumers in EnerNOC's (2013) GreenButton Database.[9] This database includes 98 facilities throughout the United States in numerous industries with different load profiles. We focus on 22 facilities located in the Southern California Edison utility territory in order to capture climatic and industrial characteristics of our region of interest. These facilities are in a range of sectors including Banking/Financial Services (1), Commercial Real Estate (1), Grocery/Retail (17), and Food Processing (3). Second, we use hourly solar radiation and weather data from the National Solar Radiation Data Base geo-located to each of the 22 consumer sites (NSRDB, 2018). This allows us to compute site-specific hourly solar PV output and panel efficiencies.

Third, we utilize the CPUC's Avoided Cost Model (ACM) to establish a measure of the marginal cost of providing energy services and proxy for the value of generation from behind-the-meter solar PV and energy storage.[10] The ACM separates California into 16 Climate Zones and computes hourly avoided costs of providing energy services separated into 8 categories: energy, losses, ancillary services, environmental emission compliance costs, renewable portfolio standard costs, and generation, transmission, and distribution capacity costs (CPUC, 2016; E3, 2018).

4 Empirical Methodology

We utilize the optimization algorithm Distributed Energy Resources Customer Adoption Model (DER-CAM) to understand the relationship between solar PV and solar PV plus energy storage systems and the value of DERs, and how this relationship varies by the prevailing retail rate design.[11] In particular, for a given retail tariff structure, we utilize DER-CAM to simulate both the optimal hourly storage charge and discharge profiles and the optimal solar PV and solar

[9]This includes demand data for a continuous period of 12 months from January 1, 2012 to December 31, 2012. The facilities did not have any rooftop solar PV or energy storage systems (Neubauer and Simpson, 2015).

[10]The ACM has been in development since 2004 to value hourly energy production from DERs. The ACM has been used extensively in CPUC analyses (e.g., see CPUC (2013a, 2016)).

[11]DER-CAM was developed by Lawrence Berkeley National Laboratory to determine the optimal capacity and operation of DERs (LBNL, 2018).

PV plus storage investment decisions. DER-CAM allows us to account for key factors such as hourly consumer demands, electricity tariffs, site-specific solar radiation and temperature, and DER technology costs, efficiency, and performance characteristics. We then utilize hourly avoided costs from the CPUC's ACM and assumptions on solar and storage capital costs to understand their private financial and overall network value.

4.1 Optimization Program

For each tariff structure, we consider two settings. First, solar PV and energy storage capacities are exogenous. This allows us to cleanly isolate the impact of adjusting the tariff structure on the financial and economic impacts of a behind-the-meter DER system. Second, we endogenously solve for the optimal solar PV and solar PV plus energy storage capacity decisions. We outline the characteristics of the fully endogenous model in DER-CAM.[12] In the fully endogenous model, the choice variables reflect the level of solar capacity, battery capacity, and optimal charge and discharge decisions of the battery. In the exogenous capacity setting, the optimization program chooses the optimal charge and discharge decisions for a given battery storage system.

The optimization problem is deterministic and solved using a representative year based on hourly demand profiles.[13] For numerical tractability, DER-CAM utilizes three representative day-types with 24 hourly time periods to construct the demand profiles for each month: (a) weekdays, (b) weekends, and (c) a peak day (an outlier day with high demand). The optimization problem reflects a mixed-integer linear programming (MILP) problem.

For each month m, day d, and hour h, total cost reflects the summation of three retail rate components (Fixed, Maximum Demand Charges [MDC], and Variable Energy Charges), technology costs (capital expenditures [CAPEX] and operating expenditures [OPEX]), and revenues earned from exporting energy (e.g., from solar panels) to the network:

$$C = \sum_{m} (Fixed + MDC) + \sum_{m} \sum_{d} \sum_{h} VariableEnergy + CAPEX + OPEX - ExportRev. \quad (1)$$

The algorithm operates under several key constraints. First, the Behind-the-Meter Energy Balance constraint ensures that hourly supply from on-site solar PV, net supply from energy storage (discharged - charged energy), and electricity supplied by the utility must equal on-site demand. Second, the Solar PV Output Constraint maps hourly solar radiation to solar PV output based on panel efficiency and the maximum capacity of the solar PV system. Third, there are several energy storage charge and discharge constraints: (i) the current state-of-charge equals the net charged energy this period (charged - discharged energy) plus the state-of-charge last period times energy losses due to decay; (ii) the current state-of-charge has to exceed the minimum state-

[12] A detailed description of the model is provided in the Appendix. See Cardoso et al. (2017) for additional details.

[13] The addition of stochastic demand and solar output would reduce the facility's ability to utilize energy storage to offset MDCs. We anticipate that this would reduce the financial value of a battery system in tariff structures with a higher reliance on MDCs. The stochastic extension of our analysis is left for future research.

of-charge required, but cannot exceed maximum battery capacity; and (iv) hourly charge and discharge quantities cannot exceed the maximum hourly charge and discharge rates, respectively.

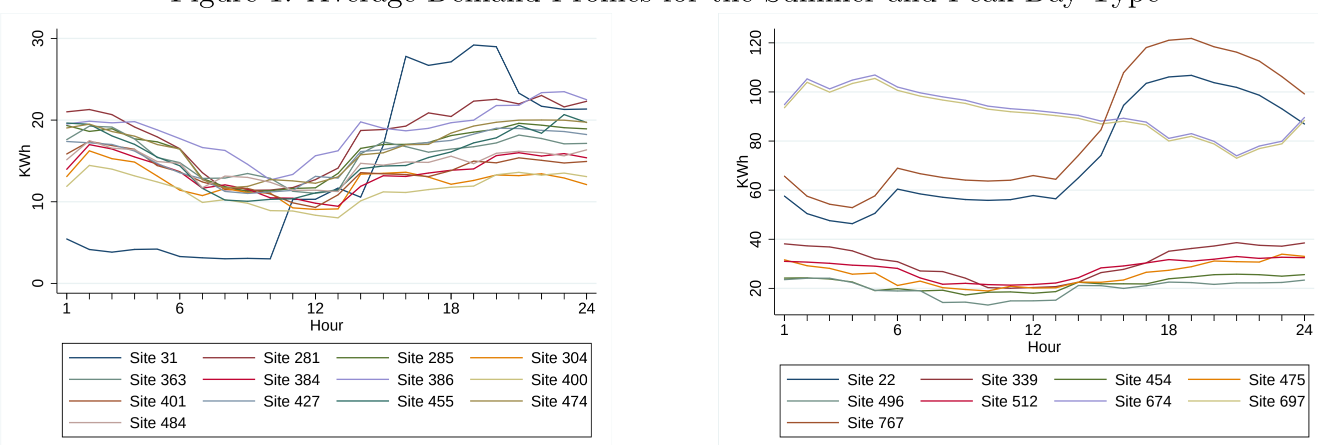
The optimal storage schedules aim to minimize the consumer's electric costs for a given baseline consumption profile, time-varying electricity prices, monthly maximum demand charges, solar capacity, and storage capacity, accounting for operational characteristics and constraints.

4.2 Demand Profiles and DER Technologies

The hourly loads in our sample reflect 22 representative large commercial and industrial facilities utilizing 12-month smart meter data from EnerNOC's (2013) Green Button database. For numerical tractability, the DER-CAM program establishes monthly consumption profiles for three representative day types: weekend, weekday, and a peak (high demand) day.[14] These demand days are scaled up to reflect a representative month of hourly demands.

For each of our 22 sites, we establish the monthly representative day types by constructing an average weekend and weekday demand profile. The representative peak day is constructed by selecting the highest demand day within a given month.[15] We regress observed weekday and weekend hourly demands by our hourly weekday and weekend profiles to investigate if our representative demand profiles capture observed variation in demands throughout the month. Our representative demand days capture observed hourly demand variation well with average R-squared values of 0.892 and 0.918 for our weekday and weekend day types, respectively.

Figure 1: Average Demand Profiles for the Summer and Peak Day Type



(a) Small Facilities

(b) Medium and Large Facilities

Figure 1 illustrates representative hourly demand profiles for summer months for the peak day

[14]MDCs can be imposed on peak demands averaged over various degrees of granularity: 5, 15, 30, or 60 minutes. For numerical tractability, demands are aggregated to 60 minute intervals where MDCs are imposed on peak demands in this interval. While increased granularity will better approximate within hour demand variation, we anticipate that our qualitative conclusions will persist when MDCs are imposed on shorter averaging intervals.

[15]We selected the representative monthly peak demand day by either the highest total electricity consumption within a given day or the highest hourly consumption hour within a given day. Both approaches systematically result in the same day being selected as the representative peak demand day.

type.[16] There are three distinct categories of demands: Small, Medium, and Large consumers. Within and across these categories, our sample includes a diverse distribution of demand profiles. This variation provides different opportunities and incentives for demand reduction via energy storage that are likely to arise in the broader population of commercial and industrial consumers.

In our baseline analysis, we assume that the demand profiles are unchanged as we vary the retail tariffs. Recent research finds limited peak to off-peak load shifting for C&I consumers (less than 3%) when facing changes in time-of-use tariffs (Jesseo and Rapson, 2015; Faruqui et al., 2016). We carry out comparative statics on the baseline demand profiles to ensure that our results are robust to behavioral changes in consumption. See the Technical Appendix for details.

In order to carry out our analysis, we need to establish assumptions regarding the capital and operation costs, as well as operational efficiencies of the storage technology. There is a broad range of capital costs for commercial and industrial rooftop solar PV and battery storage. For solar PV, capital costs range from $900/KW to $3750/KW (Cardoso et al., 2017; Lazard, 2017a; Hanna et al., 2017; Fu et al., 2017; Mclaren et al., 2018). We take the midpoint of this range $2,325/KW which falls closely to estimates in Lazard (2017a), Hanna et al. (2017), and Fu et al. (2017). We follow McLaren et al. (2018) and assume operating and maintenance costs of $0.66/KW-month. We follow the referenced literature and assume solar PV has a lifetime of 20 years.

We focus on Li-ion battery storage capital costs. There is a broad range of capital cost ranging from $350/KWh to $1260/KWh (Hanna et al., 2017; Cordoso et al., 2017; Lazard 2017b; IRENA, 2017). We assume capital costs equal to $560/KWh which closely reflect estimates from Cordoso et al. (2017) and the midpoint estimate in IRENA (2017). In addition, the CPUC provides subsidies for batteries ranging from $300-$500/KWh (CSE, 2017). We use the lower bound of this range resulting in a net capital cost assumption of $260/KWh.[17] We follow the referenced literature and assume the battery has a lifetime of 5 years, 30% of total capacity that can be charged and discharged per hour, and a charge and discharge efficiency of 0.90 (i.e., a loss of 20% of energy round-trip). Lastly, we assume that the cost of capital is 7% reflecting corporate bond rates.[18]

4.3 Avoided Cost and DER Value

We use the Avoided Cost Model (ACM) which has been utilized in CPUC's Distributed Energy Resource Avoided Cost Proceedings to capture the potential value of solar PV (CPUC, 2013a; E3, 2018). The ACM computes a forward-looking estimate of the cost of providing an additional unit of energy services for every hour of the year.[19] The detailed ACM allows us to proxy for the avoided cost associated with a unit of output from a DER. DER output either induces a reduction in demand from the utility or a direct exporting of energy to the grid to be supplied to another

[16] Alternative day types and months generate similar demand profiles. These figures are available upon request.
[17] IRENA (2017) estimate unsubsidized capital costs of Li-ion batteries will decrease below $250/KWh by 2030.
[18] As we note below, our qualitative conclusions are robust to alternative capital costs and discount rate assumptions.
[19] It is important to note that utilities in California utilize a methodology similar to the ACM to defend their proposed retail tariffs (e.g., see CPUC (2017d)).

consumer with positive net demand, offsetting provision of energy services from the utility.

The ACM is calculated for 16 Climate Zones in California and separates the marginal avoided cost into 8 components: energy, losses, ancillary services, emissions costs, renewable portfolio standard, and generation, transmission, and distribution costs. Energy and losses estimate the hourly marginal cost of providing a unit of energy from the wholesale market to end-users (adjusted for line losses). Ancillary services estimate the marginal cost of providing reliability services for grid reliability. Emissions costs compute the marginal cost of CO2 emissions associated with the marginal generation technology based on projections of California's cap-and-trade policy. The renewable portfolio standard (RPS) reflects the avoided costs associated with reducing the need to procure additional renewable output to meet RPS requirements. Lastly, there are three capacity-related cost components. Generation capacity reflects the avoided costs due to avoiding the procurement of additional production capacity to meet peak demand. Similarly, Transmission and Distribution (T&D) capacity reflects the costs of expanding T&D capacity to meet system peak demand.[20]

We utilize the ACM to compute 20-year levelized avoided cost for each Climate Zone in SCE's utility territory with 2017 as the base year.[21] We geo-locate each facility in our sample to each Climate Zone to match the facility with the appropriate avoided cost values.[22] We separate the avoided cost associated with DER output into two categories. First is the marginal avoided energy, line losses, ancillary services, and environmental compliance costs due to reduced consumption of variable electricity services from the utility (i.e., energy costs). Second is the avoided capacity costs associated with generation, distribution, and transmission capacity (i.e., capacity costs).

Figure 2 presents the marginal avoided cost for Climate Zone 6 averaged by hour and month in aggregate, and for our two subcategories.[23] Figure 2a demonstrates that there is a sizable amount of variation in the total marginal avoided costs throughout the year and within a given month. In the spring months, hydro production is high resulting in low marginal avoided costs. However, in the summer months, the marginal avoided costs increase substantially. This is particularly acute in the midday and evening hours. Figure 2b demonstrates that energy-related avoided costs are elevated in these hours. However, as shown in Figure 2c, the key driver of the elevated marginal avoided costs arises because of network capacity constraints. The network capacity marginal avoided costs are highly concentrated in the summer months when demand is at its peak in Southern California.

Figure 2 demonstrates that the precise timing of solar PV and solar PV plus storage output is critical in determining the value that they provide to the network. Figure 3 overlays the average hourly solar capacity utilization across all facilities in our sample and hourly marginal avoided

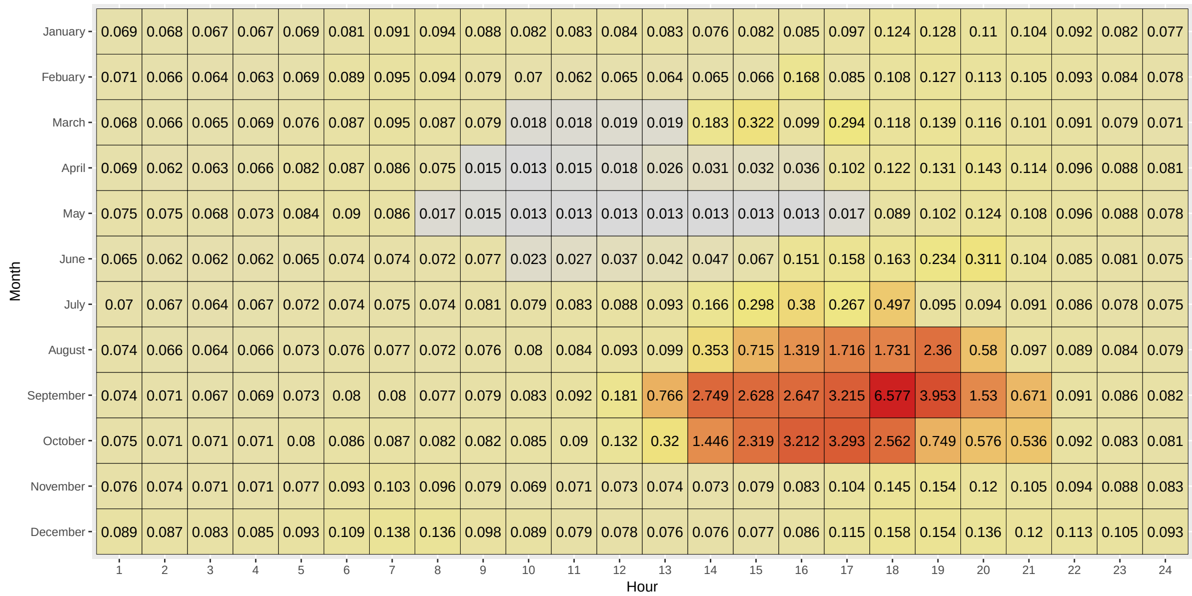
[20] See CPUC (2013a) and E3 (2018) for a detailed treatment of each marginal avoided cost component.

[21] This reflects the 20-year time horizon considered in our analysis. We also utilize the ACM to compute levelized cost on a one-year basis. This generates lower avoided cost values, but the qualitative conclusions remain.

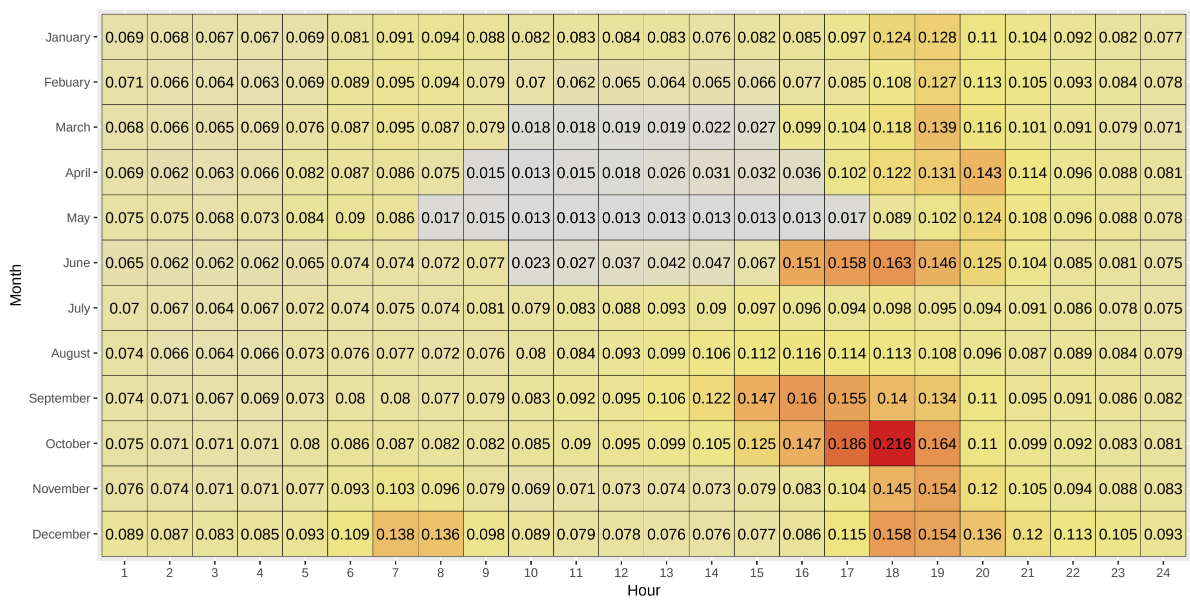
[22] While the precise quantitative results are sensitive to the assumptions underlying the ACM, we believe that it provides a proxy for the time-varying network costs and constraints of providing energy services. This allows us to capture the interaction between retail rate design and the value and implications of increased DERs.

[23] The avoided costs in other Climate Zones generate similar results. The differences across Climate Zones arise in the timing and magnitude of the capacity-related marginal avoided costs reflecting variation in network constraints.

Figure 2: Average Avoided Costs for Climate Zone 6 by Month and Hour



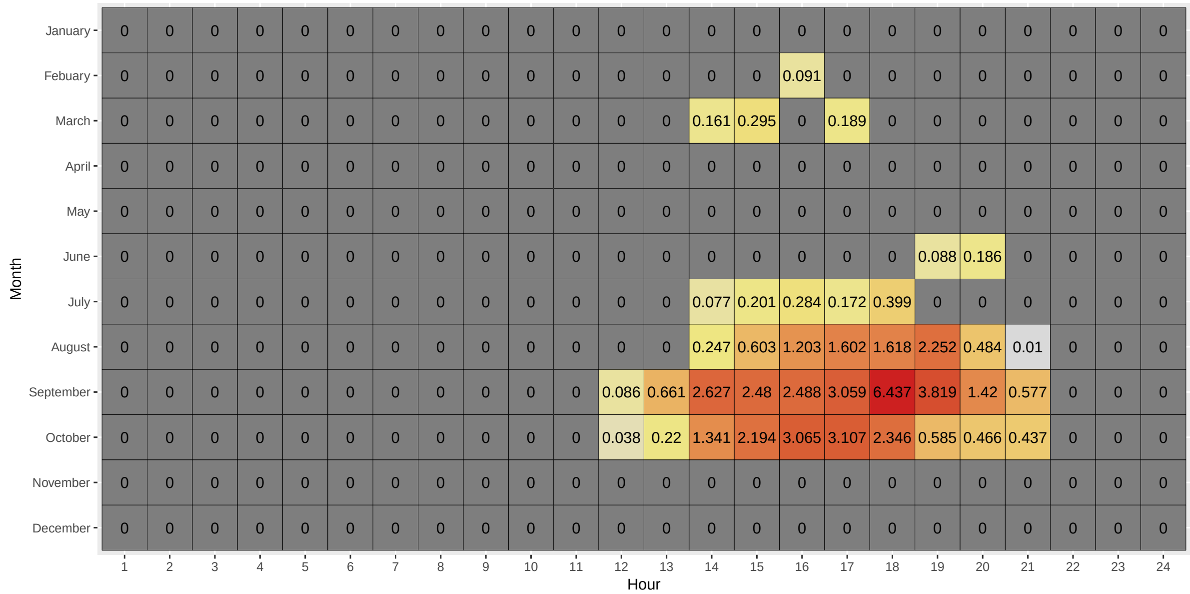
(a) Total Marginal Avoided Cost ($/KWh)



(b) Energy, Losses, RPS, Ancillary, and Emission Marginal Avoided Costs ($/KWh)

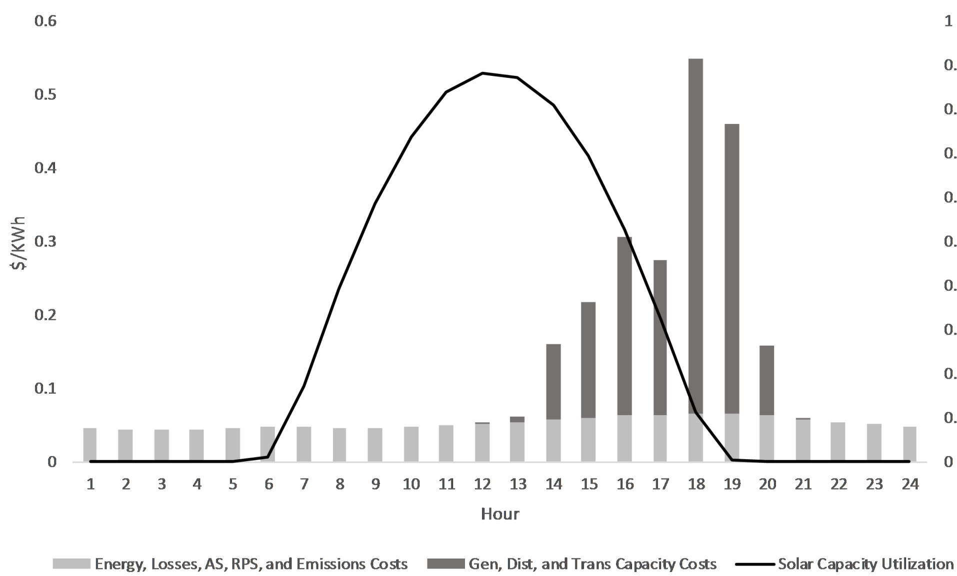
cost for the peak (high demand) day type by avoided cost category for the summer months (June - September). Figure 3 illustrates that solar PV output tends to be highest in hours with lower marginal avoided costs.[24] The addition of energy storage to a solar PV system can alleviate the mismatch between solar PV output and marginal avoided cost. As we demonstrate below, the retail rate design impacts the effectiveness of storage to offset the mismatch in timing.

[24]Similar results hold for other day types and months of the year. However, the marginal avoided cost magnitudes



(c) Generation, Transmission, and Distribution Capacity Marginal Avoided Costs ($/KWh)

Figure 3: Average Avoided Cost and Solar Capacity Utilization for the Summer Peak Day Type



The ACM provides an avoided cost measure for each hour of the year. However, as noted above, for numerical tractability we establish three representative load profiles by day type (weekday, weekend, peak) for each facility and month. As a result, we cannot simply overlay the ACM hourly data to our representative load profiles. Similar to the demand profiles, we establish monthly representative avoided cost profiles by constructing average weekend and weekday 24 hour avoided cost profiles. We regress observed weekday and weekend avoided costs by our representative hourly

are lower as capacity-related avoided costs are magnified in the summer months (recall Figure 2c).

weekday and weekend avoided cost profiles. While there is a sizable amount of variation in total avoided costs across days, the aggregated avoided cost profiles broadly capture observed hourly avoided cost variation well with average R-squared values of 0.61 and 0.695 for our weekday and weekend avoided cost profiles, respectively.

The monthly peak day avoided cost profile is chosen by selecting the day with the highest average avoided cost.[25] As we discuss in more detail below, the peak avoided cost day profile allows us to investigate several scenarios where facilities' peak consumption day types do or do not overlap with high network constrained days where avoided costs are elevated (which is captured by our representative avoided cost peak day profile).

4.4 Retail Rate Designs

We consider Southern California Edison's existing and proposed TOU tariffs for commercial and industrial consumers, TOU-GS-2 options B and R (existing and proposed rates). Option B reflects a standard TOU C&I rate class, while Option R is designed to target consumers who install or own eligible behind-the-meter DER technologies. The existing tariffs reflect the prevailing 2018 TOU schedule. Alternatively, in compliance with CPUC's (2015) mandate, the proposed rates shift the on-peak hour from 12:00 - 6:00 PM to 4:00 - 9:00 PM to better reflect system constraints. In addition, SCE's tariffs are subject to a net energy metering (NEM) where consumers are only charged for their net consumption (e.g., consumption of electricity minus on-site solar output). Consequently, through the NEM credit, solar output is effectively compensated at the prevailing retail rate. Under TOU pricing, the retail rate and the associated NEM varies across the day.[26,27]

Figure 4 illustrates the TOU option B (TOUB) and option R (TOUR) rates for the existing and proposed weekday rate classes for the summer months. The TOUB and TOUR rate classes differ only in how they are designed to recover the utility's costs, with TOUB designed to recover costs primarily via MDCs and TOUR recovers these costs through TOU volumetric charges (SCE, 2017). MDCs charge consumers for their peak consumption over a specified length of time (e.g., 1 hour, 30 minutes, 15 minutes) in a given month. MDCs can come in the form of non-coincidental MDCs which are imposed on a consumer's private maximum consumption across any hour of the day or time-specific MDCs which charge consumers for their private maximum consumption in certain hours (e.g, on-peak, mid-peak, or off-peak). TOUB imposes both non-coincidental and time-specific MDCs, whereas TOUR only imposes a smaller non-coincidental MDC.

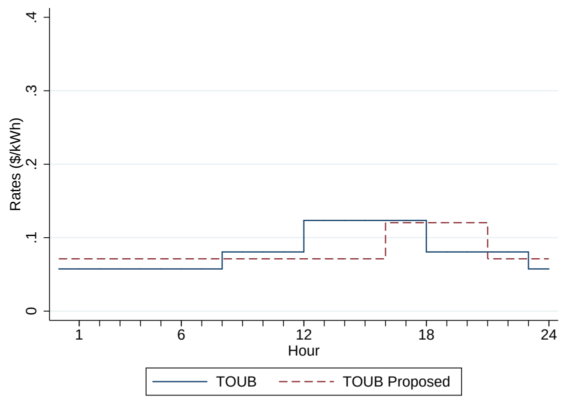
MDCs can also take the form of coincidental peak MDCs that charge consumers for their maximum consumption during hours where the system is constrained. We consider a variation on the existing and proposed rates where we shift all existing MDCs across non-coincidental and time-specific MDCs into a single coincidental peak MDC (Coin. MDC). We utilize the avoided cost

[25] We also investigated selecting the representative peak day avoided cost profile by selecting the day with the highest aggregate avoided cost. Both approaches systematically result in the same day being selected.

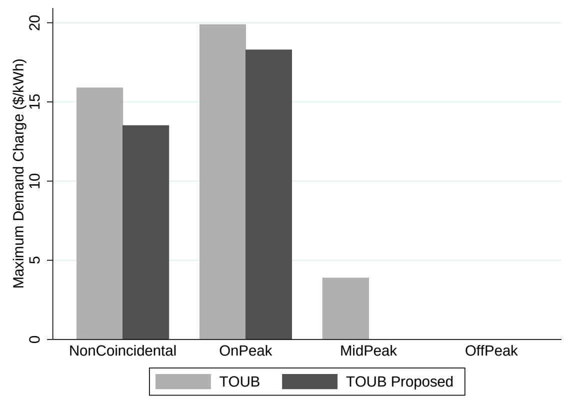
[26] See SCE (2017, 2018) for additional details.

[27] The precise details of NEM can vary widely by jurisdiction. For additional details, see Revesz and Unel (2017).

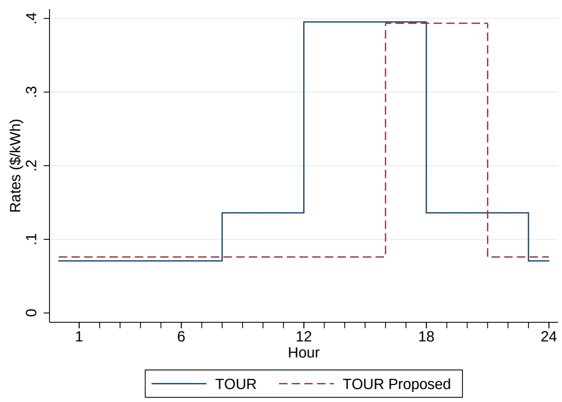
Figure 4: SCE's Existing and Proposed TOUB and TOUR Summer Weekday Rates



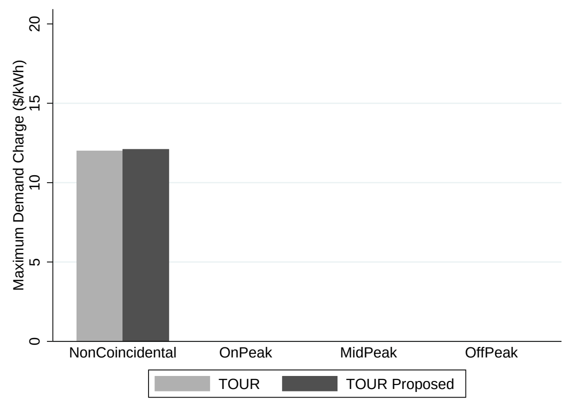
(a) TOUB and TOUB Proposed Volumetric Rates



(b) TOUB and TOUB Proposed MDCs



(c) TOUR and TOUR Proposed Volumetric Rates



(d) TOUR and TOUR Proposed MDCs

model detailed above to pre-specify a month-specific hour which reflects the hour with the highest average avoided cost.[28] The coincidental peak hours vary across months and Climate Zones with the majority of the hours concentrated between 5 - 8 PM, and a few arising in earlier evening hours (2 - 5 PM) in the summer months for certain Climate Zones. Thus, we consider eight retail tariffs in our analysis broken down into Option B or R, existing or proposed on-peak hour definitions, and if all MDCs are shifted to be coincidental peak MDCs: (i) four TOUB rate class tariffs (TOUB, TOUB Proposed, TOUB Coin. MDC, and TOUB Proposed Coin. MDC) and (ii) four TOUR rate class tariffs (TOUR, TOUR Proposed, TOUR Coin. MDC, and TOUR Proposed Coin. MDC).

For additional details on the retail rates for the TOUB and TOUR existing and proposed retail rate structures, see Tables B.1 and B.2 in the Appendix.

[28]In practice, coincidental MDCs can be more extreme charging consumers for their consumption in a single interval that reflects the most constrained time interval in a month. This approach has been criticized because of the inability of consumers to know which time-interval reflects the system constrained period (Biggar and Reeves, 2016). We consider the case where the regulator pre-specifies the hours in a month in which the system is expected to be highly constrained. The MDC is imposed on a consumers' maximum consumption in the pre-specified hour.

4.5 Exogenous Capacity

Our baseline analysis assumes that there is an exogenous amount of solar PV or solar PV plus storage capacity. The size of the PV capacity that is typically installed by homeowners or businesses depends on factors such as their 12-month prior electricity usage, desired bill offset, and available roof space. While some customers may size the system to offset their entire annual consumption, other customers install systems that offset their consumption during hours in which they are exposed to the highest billing tier (in an increasing block pricing schedule) or on-peak TOU pricing periods. Consequently, there is no simple rule-of-thumb in sizing a PV system.

We assume that the C&I sites in our data install a PV system with a capacity large enough to offset 50% of their consumption during their average annual peak (high demand) day.[29] More specifically, we select the peak day for each month to estimate the average daily peak day electricity usage in the year. We use solar irradiation data from the National Solar Radiation Database to measure expected solar PV output for the Los Angeles region. We translate the solar irradiance data to PV power generated by scaling the data to average daily hours of full sun equivalent and use a derating factor that accounts for environmental factors such as shade, dirt, and energy losses. We use NREL PV Watts's default derate factor 0.77. The power output is divided by the derate factor to obtain the PV capacity size necessary to achieve our 50% target.[30]

The size of the storage capacity to install depends on the reason for installing storage (e.g., avoiding solar exports or demand charge mitigation). Under current net energy metering rules, SCE pays solar exports the prevailing retail rate creating a strong incentive for a facility to export excessive solar output at the higher on-peak rates (SCE, 2018). Thus, avoiding solar exports is not a primary driver for installing storage. The prevailing literature has identified maximum demand charge reduction as a primary driver for C&I consumers to install energy storage (e.g., McLaren et al., 2018). Consequently, we assume that the main reason for battery storage is to reduce maximum consumption in the period where the household is not exporting solar power to the grid.

We define the exogenous storage capacity as the amount of energy storage required to flatten the facility's load profile in hours where there is no solar export to the grid.[31] We estimate the average solar generation during each hour given the exogenous solar PV capacity detailed above. We focus on hours where there is positive net consumption from the grid (i.e., demand exceeds solar output). Define L_{it} to be facility i's net load in hour t with zero solar exports. The storage capacity denoted as E_{max} is the sum of the positive deviations from facility i's average net load $\bar{L}_i$. This capacity measure reflects the energy storage that yields maximum demand charge reduction.

[29]Neubauer and Simpson (2015) utilize a similar methodology to scale solar PV capacity such that its generation equals 50% of their representative peak facility demand.

[30]For example, suppose a hypothetical commercial site in Los Angeles has an average peak day consumption of 1600 kWh and 6 hours of full sun equivalent. Then the PV power output required to meet 50% of the daily consumption equals $\frac{800KWh}{6h} = 133.33KW$. Using NREL PV Wattss derate factor of 0.77, the PV system size is given by $\frac{PowerOutput}{derateFactor} = \frac{133.33KW}{0.77} = 173.16KW$.

[31]Neubauer and Simpson (2015), however, defines the maximum storage capacity as the amount of storage required to perfectly flatten the load, without restricting the time to hours with no solar exports.

This approach generates exogenous solar PV capacity numbers that range from 26.35 to 198.58 KWs, with an average of 58.11 KWs and standard deviation of 45.08 KWs. This results in annual solar PV output equal to 74.5% of annual consumption on average. The energy storage capacities range from 6.67 to 93.2 KWhs, with an average of 24.8 KWhs and standard deviation of 29.05 KWhs. The ratio of storage to solar PV capacity ranges from 0.218 to 0.65, with an average of 0.28 and standard deviation of 0.093.

We abstract from roof area constraints and different solar panel tilts.[32] Our primary objective is to capture the variation in solar PV output over the day and year, and to understand how retail rate structures impact the financial and economic value of solar PV and battery storage systems as well as the optimal charge and discharge incentives of behind-the-meter storage.

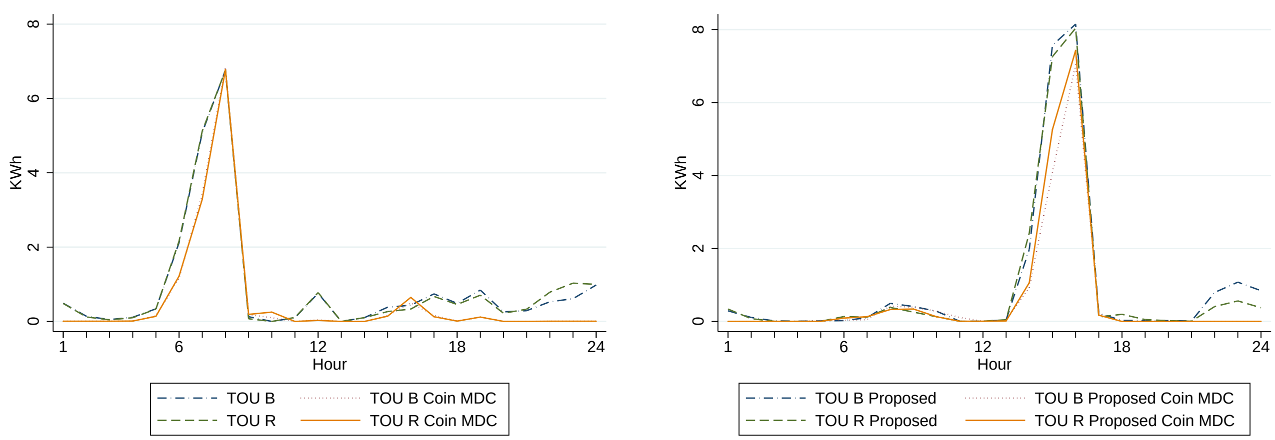
5 Primary Findings

We focus on the exogenous capacity setting in order to isolate the impacts of retail rate design details on the private and avoided network costs associated with solar PV and solar plus storage systems. Section 6 extends our analysis to include endogenous capacity investment.

5.1 Charge and Discharge Decisions

Solar PV output is exogenous to the prevailing rate structure and depends on several factors including panel efficiency, solar radiation, and weather. Alternatively, we demonstrate that the rate structure has important impacts on the charge and discharge decisions of the battery system.

Figure 5: Average Peak Day Charge Decisions by Tariff Structure



(a) Existing Tariffs (b) Proposed Tariffs

Figure 5 presents the average hourly charge decisions by tariff structure for the peak day type across all facilities and months.[33] Under the existing tariffs, the battery is charged in the off-peak

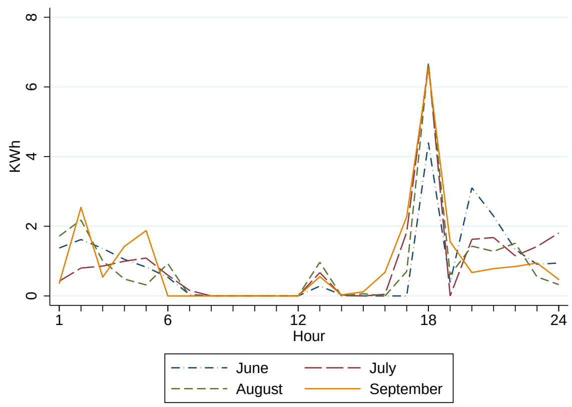
[32] Davidson et al. (2015) estimate usable roof area based on a detailed analysis of rooftop PV suitability of medium and large buildings and concluded that one-story buildings such as schools, industrial facilities, grocery stores, small offices, and strip malls can generate 50% or more of their annual energy use with rooftop solar.

[33] The charge decisions demonstrate similar patterns when decomposed by weekend, weekday, and across months.

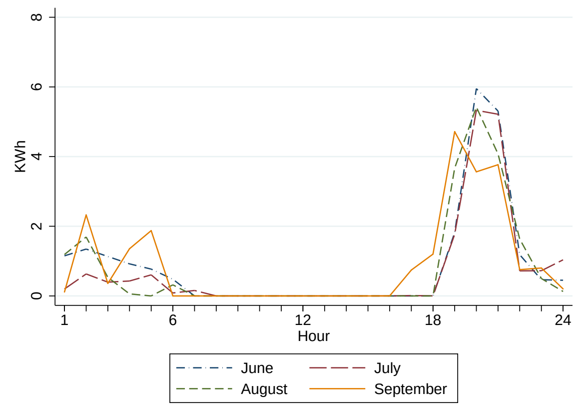
early morning hours by extracting more electricity from the grid. Under the new proposed tariffs, the battery is charged in the off-peak period in the middle of the day when on-site solar PV output is high. The different charging incentives are driven largely by the definition of the on-peak period. The on-peak period begins in Hour Ending (HE) 17 (4 PM – 5 PM) under the proposed tariffs, while on-peak begins in HE 13 (12 PM – 1 PM) in the existing tariff structure.[34]

Next, we analyze the battery discharge (supply) decisions for each tariff structure. We investigate discharge decisions by season and day type. The seasonal variation in incentives is driven by the change in the tariff structure from the winter to summer seasons (see Tables B.1 and B.2). The differences by day type are driven by the fact that during peak demand days, the battery discharge decisions are driven in part by the incentive to avoid maximum demand charges.

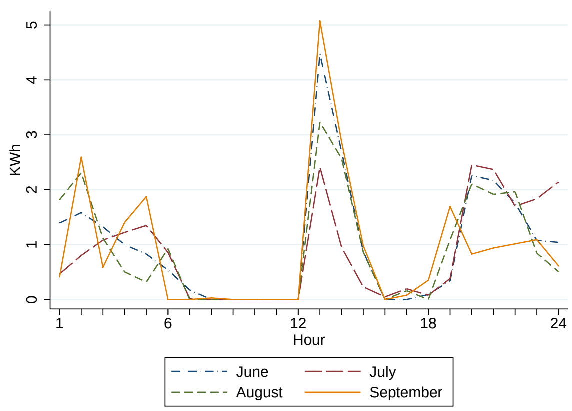
Figure 6: Battery Discharge Decisions by Tariff Structure for the Summer Peak Day Type



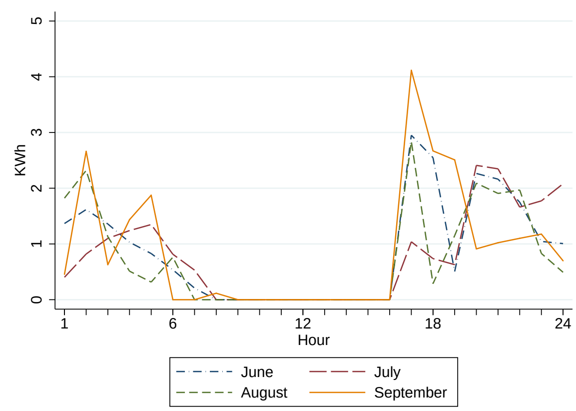
(a) TOUB



(b) TOUB Proposed



(c) TOUR



(d) TOUR Proposed

Figure 6 presents the average battery discharge decisions by tariff structure for the peak demand day type in the summer. Under TOUB and TOUB Proposed, storage is discharged to avoid the facility-specific on-peak MDCs. This induces facilities to consistently discharge the battery in HE

[34]In both cases, the battery is charged in the final off-peak hours. This occurs because there is a (small) loss of stored energy overtime. As a result, there is an incentive to charge the battery in the final off-peak hours.

18 (5 PM - 6 PM) under TOUB and between HE 18 - 21 (5 PM - 9 PM) under TOUB Proposed. This discharging profile arises because a facility's maximum consumption systematically arises in HE 18 in the existing on-peak hours HE 13 - 18 (12 PM - 6 PM). Alternatively, under the proposed on-peak hours HE 17 - 21 (4 PM - 9 PM), a facility's maximum consumption systematically arises in HE 18 - 21. In contrast, under TOUR and TOUR Proposed where MDCs are low, the battery is discharged to arbitrage on the high peak to off-peak volumetric price differential. This induces the facility to discharge the battery in the first few hours exposed to the on-peak rate which arises in HE 13 - 14 and HE 17 - 18 under the existing and proposed tariffs, respectively.

The shift in the on-peak hour definition results in a shift in discharge decisions to be later in the evening under both the TOUB and TOUR tariff structures. However, the precise incentive for discharging the battery differs under each tariff structure. Under the TOUB tariff class, the battery is discharged to avoid a facility's private on-peak MDCs, whereas the battery is discharged to arbitrage on the peak to off-peak volumetric price differential under the TOUR tariff class. Under all four tariffs, storage is also discharged infrequently in the late evening and early morning where a few facilities' non-coincidental MDCs are imposed on their overall peak demands.

Table 1 presents a summary of the discharge decisions across all eight tariff structures by season for the peak day type. There are four primary reasons to discharge the battery: (i) to avoid non-coincidental MDCs (Non-Coin. MDC); (ii) to reduce on-peak MDCs (On-Peak MDC); (iii) to arbitrage on the peak to off-peak volumetric rate (On-Peak Marginal Rate); and (iv) to avoid coincidental MDCs (Coin. Peak MDC). Table 1 presents several additional findings. Under the TOUB and TOUR tariffs classes, in the winter months the battery is discharged primarily to avoid non-coincidental MDCs. In any season, the battery is primarily discharged to avoid coincidental peak MDCs when they are imposed.[35] In the presence of coincidental MDCs, there is also an incentive to utilize the battery to arbitrage on the peak to off-peak price differential.

The discharge incentives differ for the weekday day type where MDCs are less likely to be imposed on consumption. In this setting, the primary discharge incentive is to arbitrage on the peak to off-peak retail price differential. The shift from the existing to proposed tariffs results in a shift in battery discharging from HE 13 - 14 to HE 17 - 18 due to the new on-peak hours definition. Table B.3 and Figure B.1 in the Appendix provide additional details on the weekday discharging decisions. The battery is discharged infrequently on the weekend day type when the MDC is rarely imposed and the volumetric tariff is largely flat across the hours of the day.

5.2 Changes in Maximum Demand

We investigate the impact of solar PV and solar PV plus storage systems on changes in facility-specific maximum consumption withdrawn from the utility compared to the baseline demand profile. Table 2 presents the percentage change in maximum demand by month across all hours and within coincidental peak hours where the network is constrained. The percentage change is

[35] Figure B.2 in the Appendix illustrates the discharge incentives in the summer peak day with coincidental MDCs.

Table 1: Comparison of Discharge Incentives by Tariff and Season for the Peak Day Type

Season	Tariff	Non-Coin. MDC	On-Peak MDC	On-Peak Marginal Rate	Coin. Peak MDC
Summer	TOUB	HE: 1-6, 19 - 24	HE: **<u>18</u>**		
	TOUB Prop	HE: 1-6, 19 - 24	HE: 19, **<u>20, 21</u>**		
	TOUR	HE: 1-6, 19 - 24		HE: **<u>13</u>**, 14	
	TOUR Prop	HE: 1-6, 19 - 24		HE: **<u>17</u>**, 18	
	TOUB Coin. MDC			HE: **<u>13</u>**, 14	HE: **<u>18</u>**, 19, 20
	TOUB Prop Coin. MDC			HE: 17, **<u>18</u>**	HE: **<u>18, 19</u>**, 20
	TOUR Coin. MDC			HE: **<u>13</u>**, 14	HE: **<u>18</u>**, 19, 20
	TOUR Prop Coin. MDC			HE: **<u>17, 18</u>**	HE: **<u>18</u>**, 19, 20
Winter	TOUB	HE: 1-6, **<u>19</u>** - 24			
	TOUB Prop	HE: 1-6, **<u>19</u>** - 24			
	TOUR	HE: 1-6, **<u>19</u>** - 24			
	TOUR Prop	HE: 1-6, **<u>19</u>** - 24			
	TOUB Coin. MDC				HE: 16, **<u>18 - 20</u>**
	TOUB Prop Coin. MDC			HE: 17, **<u>18</u>**	HE: 16, **<u>18 - 20</u>**
	TOUR Coin. MDC				HE: 16, **<u>18 - 20</u>**
	TOUR Prop Coin. MDC			HE: 17, **<u>18</u>**	HE: 16, **<u>18 - 20</u>**

Notes. HE denotes the hour endings where the battery discharge occurred. The underlined and bolded hours represent the hours with the highest amount of discharged energy. There are four discharge incentives to: (i) avoid Non-Coincidental MDCs (Non-Coin MDC); (ii) avoid an On-Peak MDCs (On-Peak MDC); (iii) arbitrage on the peak to off-peak rate differential (On-Peak Marginal Rate); and (iv) avoid a coincidental MDCs (Coin. Peak MDC).

constant across tariffs when only solar PV is installed because solar output is exogenous to the tariff structure. As shown above, changes in the tariff structure impact battery charge and discharge decisions. This can have important implications on changes in facility-specific maximum demands.

Table 2 Panel A illustrates that solar PV has minimal impacts on a facility's private maximum demand across all months. This occurs because the facilities' peak consumption often arises in the evening hours with minimal solar output. For the existing and proposed TOUB and TOUR tariffs, the addition of energy storage results in a sizable reduction in private maximum demand. This arises because these rate structures have MDCs that motivates the use of the battery to reduce facility-specific maximum demands. However, the reduction in private maximum demands declines substantially when coincidental MDCs are imposed. In this setting, the batteries are dispatched to

Table 2: Average Percentage Change in Facility-Specific Maximum Demand by Month and Tariff

Panel A: Average Percentage Change in Private Maximum Demand Across All Hours

Technology	Solar	Solar PV Plus Storage							
Tariff		TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
January	0.0	-14.9	-14.8	0.1	0.0	-14.7	-14.6	0.0	0.0
February	0.0	-16.5	-16.4	-1.0	-1.0	-16.5	-16.3	-1.0	-1.0
March	-0.1	-19.9	-19.8	-1.6	-1.8	-20.3	-19.0	-1.8	-1.8
April	-0.5	-14.7	-14.5	-0.7	-0.7	-14.6	-14.5	0.1	-0.7
May	-3.0	-21.8	-21.9	-3.7	-3.7	-22.1	-20.8	-3.4	-3.7
June	-0.6	-13.1	-12.3	1.0	-0.6	-14.4	-14.3	1.0	-0.6
July	-1.1	-11.6	-10.3	-0.3	-1.1	-13.3	-13.1	-0.3	-1.2
August	0.0	-10.0	-9.4	2.0	-0.3	-11.7	-11.6	2.0	-0.3
September	-0.2	-11.7	-10.9	-0.1	-0.2	-12.3	-12.4	-0.1	-1.6
October	0.0	-11.2	-11.2	2.4	0.0	-11.2	-11.2	2.4	0.0
November	-0.2	-10.1	-10.0	2.1	-0.2	-10.1	-10.1	2.1	-0.2
December	0.0	-12.4	-12.1	5.5	-1.2	-12.4	-12.2	5.5	-1.2

Panel B: Average Percentage Change in Maximum Demand in Coincidental Peak Hours

Technology	Solar	Solar PV Plus Storage							
Tariff		TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
January	0.0	-0.9	-1.6	-19.9	-19.9	-0.9	-1.6	-19.9	-19.9
February	0.0	-9.1	-9.4	-21.1	-21.1	-9.0	-9.3	-21.1	-21.1
March	0.0	-7.5	-9.8	-19.7	-19.7	-6.7	-8.1	-19.7	-19.7
April	0.0	-7.3	-7.5	-23.4	-23.4	-7.3	-7.1	-23.4	-23.4
May	0.0	-9.1	-10.5	-17.8	-17.8	-9.3	-8.9	-17.8	-17.8
June	-32.4	-32.7	-37.5	-49.9	-49.9	-28.3	-33.5	-49.9	-49.9
July	-62.6	-73.2	-62.5	-75.0	-75.0	-62.9	-62.7	-75.0	-75.0
August	-19.4	-22.3	-25.3	-36.6	-36.6	-19.2	-21.6	-36.6	-36.6
September	-11.5	-30.5	-14.9	-30.9	-30.9	-12.4	-19.2	-30.9	-31.0
October	-18.7	-19.5	-18.9	-35.9	-35.9	-19.4	-13.6	-35.9	-35.9
November	0.0	-2.7	-7.5	-19.8	-19.9	-2.7	-2.9	-19.8	-19.8
December	0.0	-5.2	-6.5	-25.3	-25.4	-5.5	-6.1	-25.3	-25.3

reduce consumption during coincidental peak hours and the facilities in our sample have maximum demands that often occur in non-coincidental peak hours.

Table 2 Panel B demonstrates that solar PV has a sizable effect on a facility's maximum demand in coincidental peak hours during the summer months because these hours arise in the late afternoon hours with positive solar PV output. Under existing tariffs TOUB and TOUR, the addition of storage systematically elevates the reduction in maximum demand during coincidental peak hours by several percentage points as the battery is discharged to either arbitrage on the peak to off-peak differential or avoid on-peak MDCs. The move from the existing to proposed tariff structures often magnifies this effect, but it can also mitigate the reduction in coincidental peak consumption. For example, as shown in Figure 6, in the summer months under TOUB Proposed, a facility often dispatches the battery to avoid on-peak MDCs on its private maximum demand that occurs late in the evening when the electricity network is relatively unconstrained. In this setting, shifting the on-peak hours to later in the evening can actually mitigate the coincidental peak demand reduction. Alternatively, when MDCs are shifted to reflect coincidental peak hours, Table 2 Panel B demonstrates that there is a systematic and large reduction in a facility's coincidental peak consumption as the battery targets demand reductions in these system constrained hours.

5.3 Private Financial Value

We now investigate the private facility-specific financial value of a solar PV and solar PV plus storage system, and how this varies by the prevailing tariff structure. We take the existing TOUB and TOUR rate structures as the baseline level of electricity charges. We consider a movement from these baseline electricity tariffs to one of the eight possible tariff combinations with the addition of either a solar PV or solar PV plus energy storage system.

When we change the retail rate structure, the total electricity costs would have changed even in the absence of any addition DER technologies. As a result, we compute the change in the total electricity cost from moving from the baseline to an alternative tariff with a DER system, net of the change that would have already occurred by changing the tariff structure in the absence of a DER system.[36] Total electricity costs reflect charges from fixed, volumetric, and maximum demand charges, net of export revenues earned from the supply of electricity to the network from solar PV when on-site supply exceeds on-site demand under a common net metering policy.

Table 3: Percentage Change in Total Electricity Costs by Technology

Panel A: Average Percentage Change in Total Electricity Costs with Solar PV

Baseline	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
TOUB	-44.10	-33.86	-46.77	-38.88	-68.20	-39.41	-70.23	-41.46
	(4.07)	(3.16)	(5.55)	(4.60)	(7.21)	(4.12)	(7.58)	(4.53)
TOUR	-41.09	-31.55	-43.55	-36.21	-63.51	-36.71	-65.40	-38.61
	(3.16)	(2.40)	(4.41)	(3.66)	(5.53)	(3.19)	(5.83)	(3.53)

Panel B: Average Additional Savings from Adding Energy Storage to Solar PV System (%)

TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
10.32	12.31	11.72	13.39	4.85	9.36	5.51	10.61
(5.78)	(7.85)	(7.99)	(8.85)	(3.27)	(6.15)	(3.60)	(6.84)

Notes. Standard deviations are presented in parentheses.

[36] More formally, for baseline tariff $j \in$ {TOUB, TOUR} and tariff $k \in$ {TOUB, TOUB Prop., TOUB Coin. MDC, TOUB Prop. Coin. MDC, TOUR, TOUR Prop., TOUR Coin. MDC, TOUR Prop. Coin. MDC}, we compute the percentage change in total electricity costs (TEC) of moving from baseline tariff j to the new tariff k with technology $i \in$ {Solar, Solar+Storage} by: $\frac{(TEC_k^i - TEC_j^{Base}) - (TEC_k^{Base} - TEC_j^{Base})}{TEC_j^{Base}}$.

Table 3 Panel A presents the average change in a facility's total electricity costs as we move from the existing baseline tariffs to one of the eight alternative tariffs with the addition of a solar PV system. Installing solar results in an approximately 31% to 70% average reduction in a facility's total electricity costs. This reduction is magnified under the TOUR rate class because solar PV output is compensated at a substantially higher marginal rate in on-peak hours (recall Figure 4).

The change in the total electricity costs is substantially smaller as we move from the existing to proposed tariffs. This arises because the on-peak period (and the higher on-peak prices) is shifted to the evening hours where solar PV output is substantially lower. This nearly eliminates the higher potential savings associated with the TOUR tariffs compared to the TOUB rate class. The addition of coincidental peak MDCs elevates the savings from adding a solar PV system. This arises because facilities are able to avoid a portion of the (large) coincidental MDCs in the summer months when coincidental peak hours occur in the afternoon hours with positive solar output.[37]

Table 3 Panel B presents the additional average bill savings that arise by adding energy storage to the solar PV system. The addition of energy storage elevates the bill savings by an additional 4.85% to 13.39% percentage points beyond the savings that accrued with a solar PV system. The additional savings are larger under TOUB and TOUB Proposed rate class because of the higher reliance on MDCs. The battery can be utilized to target reductions in MDCs. A move from existing to proposed rates elevates the additional savings associated with energy storage because of the increase in the number of hours with a peak to off-peak retail price differential (which can be arbitraged by the battery). Lastly, within a rate class, a move to coincidental peak MDCs elevates the additional savings of an energy storage system because the battery can carefully target coincidental peak hours to avoid the large MDCs.

Next, we investigate the Net Present Value (NPV) of the exogenous solar PV and solar PV plus storage systems. While the precise quantitative conclusions will depend critically on the assumed capital costs of each technology and the discount rate, the qualitative conclusions are robust to the consideration of alternative capital cost assumptions. We utilize a 20 year time horizon in our NPV calculation reflecting the assumed asset life of the solar PV array.[38]

Table 4 presents the average NPV of the exogenous solar PV and solar PV plus storage systems by tariff structure. The existing tariff structures yield positive NPVs, with the TOUR tariff generating large positive returns. This is driven by the large marginal retail rate under TOUR that yields a high rate of compensation for solar PV output. A move to the proposed rate structures reduces the profitability of both the solar PV and solar plus storage systems. Under TOUB Proposed, the NPV is negative for all facilities and technology configurations. In each rate class, coincidental MDCs increase the NPV of the solar PV and solar plus storage systems substantially as output from these technologies can offset a portion of these coincidental peak MDCs.

[37] The facilities in our sample systematically have private maximum demands that arise in the evening with low solar output. When coincidental MDCs are not imposed, the reduction in MDCs due to solar PV capacity decreases.

[38] The facilities must reinvest in the battery system every five years, incurring the associated capital costs. See Section 4.2 for additional details on the capital cost and technology assumptions.

Table 4: Net Present Value by Tariff and Technology

Panel A: Net Present Value with Solar PV

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Mean	19,232	-18,639	28,270	-226	106,263	1,939	113,947	9,687
	(16,039)	(15,960)	(24,804)	(5,925)	(85,423)	(3,518)	(92,671)	(10,126)
# > 0	22	0	22	9	22	15	22	22

Panel B: Net Present Value with Solar PV and Storage

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Mean	19,778	-19,517	32,589	2,953	101,494	-1,058	111,542	9,616
	(16,478)	(16,026)	(28,831)	(6,503)	(80,963)	(3,562)	(90,642)	(10,600)
# > 0	22	0	22	12	22	6	22	22

Notes. Standard deviations are presented in parentheses. # > 0 counts the number of facilities with positive NPVs.

The average NPV systematically decreases under the TOUR rate class when storage is added to a PV system. This arises because storage is primarily utilized to arbitrage on the peak to off-peak marginal rate under TOUR rates. The revenues are not sufficient to offset the storage capital costs. Alternatively, under TOUB the addition of storage increases the average NPV for each tariff (except TOUB Proposed). This arises because of the profitability of utilizing the storage system to avoid MDCs. The effect is magnified when coincidental peak MDCs are imposed because the MDCs are concentrated in a handful of hours that can readily be targeted.

5.4 Avoided Costs

We utilize the Avoided Cost Model (ACM) to estimate the network value of the solar PV and solar PV plus storage systems. In particular, we compute the avoided cost associated with DER output that reduces the consumers' withdraws of energy from the network or directly exports energy to the grid reducing centralized production.

As noted above, we establish monthly representative avoided cost weekend, weekday, and peak days by Climate Zone matched to our facilities' locations based on California's Climate Zones. We consider two cases based on whether a facility's peak day load profile overlaps with the representative peak avoided cost day (which corresponds to day where the network is highly constrained). Case 1 assumes that a consumer's peak day never overlaps with the monthly system peak and instead overlaps with the avoided cost profile of an average weekday. Case 2 assumes that a consumer's peak day perfectly overlaps with the high avoided cost peak day type. This approach provides us with an upper and lower bound on the avoided cost that arise from a DER system.[39]

Panel A in Table 5 illustrates the average avoided cost for total, capacity, and energy-related avoided costs by technology and tariff structure. The avoided costs associated with a solar PV

[39] As shown above, consumers have a strong incentive to discharge the battery system on their monthly peak demand day type to avoid MDCs. We demonstrate that the avoided costs of a solar plus storage system is magnified if the peak demand day perfectly overlaps with the representative peak avoided cost day type.

Table 5: Average Avoided Cost by Cost Category, Technology, and Tariff - Case 1

Panel A: Average Avoided Cost by Category and Tariff ($)

Technology	Solar	Solar PV Plus Storage							
		TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Total	10,668	10,843	10,800	10,863	10,938	10,684	11,175	10,860	11,259
	(8,596)	(8,896)	(8,790)	(8,872)	(8,952)	(8,678)	(9,104)	(8,875)	(9,184)
Energy	8,205	8,166	8,246	8,184	8,256	8,164	8,202	8,181	8,217
	(6,465)	(6,422)	(6,498)	(6,434)	(6,503)	(6,423)	(6,468)	(6,434)	(6,473)
Capacity	2,463	2,677	2,554	2,679	2,683	2,520	2,973	2,679	3,042
	(2,372)	(2,667)	(2,491)	(2,638)	(2,632)	(2,485)	(2,840)	(2,641)	(2,902)

Panel B: Average Additional Avoided Cost Due to Energy Storage (%)

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Total	1.15	0.90	1.55	2.08	0.12	3.80	1.51	4.54
	(1.03)	(1.10)	(1.01)	(1.31)	(0.54)	(4.86)	(1.04)	(4.86)
Energy	-0.38	0.42	-0.16	0.57	-0.43	-0.05	-0.18	0.16
	(0.33)	(0.53)	(0.29)	(0.42)	(0.25)	(0.11)	(0.38)	(0.08)
Capacity	9.08	5.94	14.16	15.45	1.03	26.62	13.92	32.38
	(8.62)	(8.38)	(16.87)	(19.68)	(2.68)	(29.65)	(16.64)	(34.12)

Notes. Standard deviations are presented in parentheses. Percentages reflect the percentage change in avoided costs from the Solar PV only setting. Energy avoided costs includes wholesale energy, line losses, ancillary services, and environmental compliance costs. Capacity avoided costs include capital costs of generation, transmission, and distribution infrastructure.

system is exogenous to the prevailing retail tariff because solar output is exogenous. The average annual avoided cost of a solar PV system is $10,668 with the majority of these savings (76.9%) arising from energy-related avoided costs. Alternatively, the average avoided costs vary by the prevailing tariff structure in the setting with a solar PV plus energy storage system. This is driven by the different charge and discharge incentives that arise under the various tariffs.

Panel B in Table 5 isolates the percentage change in avoided cost with the addition of an energy storage system by cost category across the various tariffs.[40] Total and capacity-related avoided costs strictly increase with the addition of an energy storage system. While the change in average total avoided costs are modest, storage can have a substantial impact on capacity-related avoided costs. Further, this effect varies by the prevailing retail tariff structure. Alternatively, average energy avoided costs can decrease (i.e., energy-related costs increase) when a battery system is added under certain tariffs based on the relative differences in energy-related costs when the battery is charged and discharged.

[40]It is important to note that the the results in Panel B differ from simply taking the percentage change in average avoided cost presented in Panel A. This arises because the average percentage change in avoided cost due to the addition of storage does not equal the percentage change in the average avoided cost of adding energy storage.

Comparing existing and proposed tariffs, the change in average total avoided costs due to the addition of a storage system decreases (increase) as we move from existing to proposed tariffs under the TOUB (TOUR) rate class. This is driven primarily by the relative changes in capacity-related value due to a battery system. Recall, under both TOUB rate structures the battery is discharged primarily to avoid the on-peak MDCs. In the consumer load profiles in our sample, for the existing on-peak hours (12 – 6 PM) the facilities' private on-peak maximum demands systematically occur in hours 5 – 6 PM. In the proposed on-peak window (4 – 9 PM), the facility's maximum demands occur between 7 – 9 PM. The move from TOUB to TOUB Proposed results in the battery being discharged in 7 – 9 PM instead of 5 – 6 PM to avoid on-peak MDCs. This results in a sizable reduction in capacity-related avoided costs because these costs are systematically higher between 5 – 6 PM where the battery was originally discharged under TOUB (see Figure 2c).

Under the TOUR and TOUR Proposed tariffs, the battery is discharged in the first on-peak hours to arbitrage on the on-peak to off-peak retail price differential. The shift in the on-peak hour from starting at 12 PM to 4 PM results in a sizable increase in the avoided capacity-related costs that are substantially higher in these early evening hours than they are midday. Alternatively, the increase in avoided cost associated with the addition of storage is minimal under TOUR because the battery is discharged systematically between 12 – 2 PM when avoided costs are relatively low.

Panel B in Table 5 demonstrates that the capacity-related avoided costs increase substantially when coincidental MDCs are imposed because the battery discharge incentives are aligned with the system constraints. This effect is particularly pronounced under the existing TOUR tariff because facilities have limited incentives to discharge the battery in the evening hours when the system is constrained. Rather, the battery is discharged to arbitrage on the peak to off-peak retail price differential in the afternoon hours (12 - 2 PM) when the network is largely unconstrained.

These results demonstrate several important findings. First, a shift in the on-peak hour may not strictly increase the avoided costs associated with a DER system even when the on-peak period timing better reflects system constraints. Instead, when facility-specific MDCs are imposed, a facility may discharge the battery to avoid its own private MDCs that are imposed in hours where the system is less constrained. Second, the adoption of coincidental peak MDCs can better align the incentive to reduce consumption during network stress periods via discharging battery systems. Third, when limited weight is placed on MDCs (as in the TOUR rate class) and TOU prices are adjusted to better reflect the prevailing network costs, we observe a substantial increase in the capacity-related avoided costs due to the addition of an energy storage system. Consequently, in our analysis, we find that the TOUR Proposed tariffs generate the largest avoided cost measure and additional avoided costs when energy storage is added behind-the-meter.

Table B.4 in the Appendix presents the result for Case 2 where we assume that a consumer's peak day overlaps with the high avoided cost peak day type in each month of our sample. The qualitative results demonstrated above for Case 1 persist, but the avoided cost values are elevated. In particular, the additional avoided costs associated with energy storage is magnified because the battery discharge decisions alleviate large capacity-related network constraints. Finally, we have considered average avoided costs. This abstracts from variation in the avoided cost across the 22 sites in our sample. Table B.5 in the Appendix demonstrates that the aggregate avoided costs across all sites in our sample exhibit analogous conclusions as the average avoided cost measures.

5.5 Cost-Shifting

For each facility, we compute a cost-shifting measure that calculates the difference between the change in a facility's total electricity charges and the avoided costs due to the addition of behind-the-meter solar PV or solar PV plus storage system. If the reduction in electricity charges exceeds the associated reduction in avoided costs (i.e., the cost-shifting measure is positive), then there are concerns that these costs will be passed to consumers who do not to install a DER system in order to ensure the utility's revenue requirement is satisfied to ensure its costs are recovered.[41]

Similar to the avoided cost analysis above, we consider two cases based on whether a facility's peak day load profile overlaps with the representative peak avoided cost day. Table 6 presents the results for Case 1 where a consumer's peak day never overlaps with the monthly system peak day and instead overlaps with the avoided cost profile of an average weekday.[42] The cost-shifting measure is presented in terms of annual $'s, and normalized by each facility's solar PV capacity (in KWs) and annual solar output (in KWhs).

Panel A in Table 6 focuses on the solar PV only setting. When only Solar PV is installed, the variation in the cost-shifting measure captures variation in bill savings because avoided cost is constant across all tariff structures. The existing tariffs TOUB and TOUR systematically generate positive values on the cost-shifting measure. In particular, the TOUR tariff yields large values reflecting the favorable bill savings associated with this tariff structure (recall Table 3). The move to the proposed tariff structures substantially reduces the cost-shifting measure. In fact, for a sizable portion of our facilities, the cost-shifting measure is negative under the proposed tariffs. This is driven by the substantial reduction in bill savings under the new proposed tariff structures. For each tariff, the use of coincidental MDCs increases the average cost-shifting measure because of the increase in bill savings (and avoided costs remain unchanged in the solar PV only case).

The story becomes more complex when solar PV plus storage is adopted because both avoided costs and bill savings vary across tariffs. Panel B in Table 6 presents the results with solar PV plus storage. Somewhat surprisingly, for each tariff structure, the move to adding energy storage to an existing solar array increases the cost-shifting measure. While we have demonstrated that the addition of storage systematically increases the average total avoided cost of the DER system, the

[41] There has been substantial controversy whether rooftop solar PV systems can provide capacity-related value. We also estimated the cost-shifting measure that only accounts for energy-related avoided costs. As expected, this systematically elevates the cost-shifting measure as avoided costs decline. However, the qualitative conclusions are analogous to the case where we consider total avoided costs. Detailed results are available upon request.

[42] Table B.6 in the Appendix demonstrates analogous qualitative conclusions for Case 2 which assumes that a consumer's peak day perfectly overlaps with the high avoided cost peak day type for each month.

Table 6: Cost-Shifting by Technology and Tariff - Case 1

Panel A: Average Cost-Shifting Measure with Solar PV

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
$	1,614	-1,280	2,304	127	8,265	292	8,852	884
	(1,859)	(1,695)	(2,091)	(972)	(6,696)	(1,344)	(7,216)	(1,420)
$/KW	26.19	-22.65	38.56	1.00	140.52	3.56	150.13	13.26
	(24.98)	(23.82)	(16.19)	(16.77)	(24.29)	(24.07)	(21.05)	(20.86)
$/KWh	0.011	-0.009	0.016	0.000	0.058	0.001	0.062	0.005
	(0.010)	(0.010)	(0.007)	(0.007)	(0.010)	(0.010)	(0.008)	(0.008)
# > 0	19	6	22	11	22	11	22	14

Panel B: Average Cost-Shifting Measure with Solar PV Plus Storage

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
$	2,897	-63	3,856	1,516	9,301	973	9,893	1,705
	(3,066)	(1,733)	(3,729)	(2,134)	(7,650)	(1,629)	(8,169)	(2,030)
$/KW	46.00	-4.16	61.65	21.98	156.22	14.41	165.84	26.16
	(32.32)	(28.97)	(27.19)	(25.30)	(28.81)	(25.60)	(26.99)	(23.65)
$/KWh	0.019	-0.002	0.025	0.009	0.064	0.006	0.068	0.011
	(0.013)	(0.012)	(0.011)	(0.011)	(0.012)	(0.010)	(0.011)	(0.010)
# > 0	22	9	22	18	22	14	22	22

Notes. Standard deviations are presented in parentheses. # > 0 counts the number of facilities with positive NPVs. $/KW and $/KWh measures the cost-shifting measure in terms of $ per KW and per KWh of solar PV capacity and solar PV output, respectively.

electricity bill savings from adding the battery system exceeds the associated increase in avoided costs.[43] However, there is variation in the degree of this effect across the various tariff structures.

While we observed a substantial reduction in the cost-shifting measure under the TOUB Proposed and TOUR Proposed tariffs with solar PV, this effect decreases under the Proposed tariffs with a solar PV plus storage system (although on average the cost-shifting measure remains negative for TOUB Proposed). The increase in the cost-shifting measure is larger for the TOUB Proposed rates than the TOUR Proposed rates. Under the TOUB rate class, the addition of battery storage results in a sizable increase in bill savings because the battery can be discharged to avoid MDCs. However, as we illustrated in Table 5, under the TOUB Proposed tariff the additional avoided costs of adding the battery system are mitigated by the fact that facilities have an incentive to discharge the battery to avoid private peaks in demand that occur late in the evening when avoided costs are relatively low. Alternatively, the additional bill savings from adding storage

[43] This result is likely driven by the combination of two forces. First, while the utility's rates are designed to reflect the costs, SCE is restricted to reflect these costs in broad seasonal TOU prices and time-differentiated MDCs. As a result, the rate structures do not perfectly align prices with avoided costs which can vary considerably by hour, day type, and across months. In addition, in settings where the MDCs are not targeted specifically in system constrained hours, the private battery discharge incentives can result in the battery being discharged in hours where the network is relatively unconstrained generating sizable bill savings, but relatively low avoided costs. Second, the avoided costs from the ACM may differ from those utilized in SCE's retail rate design. To mitigate the potential biases induced by this approach, we utilized the ACM for the Climate Zones in SCE's territory.

are (relatively) lower under the TOUR rate class. Further, the increase in avoided cost due to the battery system is larger under the TOUR Proposed tariff as the battery is utilized to arbitrage on the peak to off-peak retail rate differential which results in the battery being discharged in the early evening hours when the system is constrained (recall Section 5.1 and Table 5).

Finally, the average cost-shifting measure is larger when coincidental MDCs are imposed. While the avoided cost analysis above illustrated that coincidental peak MDCs can elevate the total avoided costs, the current analysis raises caution that the bill savings by discharging the battery to avoid the coincidental MDCs can outstrip the elevated avoided costs. This result illustrates that rates should not be designed solely to elevate avoided costs. In this setting, our results demonstrate that cost-shifting concerns can increase when the regulator is restricted in its ability to reflect hourly variation in the costs of providing electricity services in retail rates.[44]

6 Endogenous Capacity Investment

Throughout the analysis, we have held solar PV and solar PV plus storage capacity as exogenous in order to isolate the impacts of changes in tariffs on the private and network value of DERs. In this section, we demonstrate that changes in the tariffs have important effects on investment. This impacts the avoided cost and cost-shifting concerns associated with the DER systems.

Table 7 provides the average endogenous capacity investment by technology and tariff structure. For reference, the average solar PV and storage capacities were 58.11 KWs and 24.8 KWhs in the exogenous capacity setting, respectively. We impose the constraint that annual solar PV output cannot exceed annual on-site consumption.[45] In the solar PV only setting, this constraint is binding for each site for the existing tariffs and coincidental MDC counterfactuals (i.e., TOUB, TOUB Coin. MDC, TOUR, TOUR Coin. MDC). This reflects the high profitability of investing in solar under the existing tariff structures. As we shift from the existing to proposed tariffs, investment incentives in solar PV decrease dramatically. This effect is most pronounced under TOUB Proposed, but we observe substantial reductions under TOUR Proposed as well. This is driven by the shift in the higher on-peak rates to the evening hours when solar PV output is low.

Table 7 illustrates that storage investment varies substantially by the prevailing tariff structure. The ability to invest in storage (weakly) decreases average solar PV capacity. The reduction in solar PV investment arises because batteries are utilized to reduce MDCs which were partially offset by solar output in the evening hours. Broadly, there are stronger investment incentives under the TOUB rate class where MDCs are prominent. Under TOUB and TOUB Proposed, there is relatively limited storage investment (i.e., below the exogenous capacity levels). This is driven in part by the large dispersion in MDCs across various components (i.e., on-peak, non-coincidental, and mid-peak MDCs) reducing a consumer's ability to effectively target a small subset of hours

[44]Table B.5 in the Appendix demonstrates that the aggregate cost-shifting measures across all sites in our sample exhibit analogous conclusions as the average cost-shifting measures.

[45]This reflects common regulatory constraints that restrict expected rooftop solar output to be below a consumer's previous twelve months of electricity consumption (e.g., see pg. 27 in CPUC (2017c)).

Table 7: Average Solar PV and Storage Capacity by Tariff - Endogenous Investment

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Solar PV Only	77.32	0.14	77.32	3.14	77.32	28.55	77.32	59.86
	(57.32)	(0.64)	(57.32)	(8.17)	(57.32)	(25.15)	(57.32)	(65.99)
Solar PV	77.32	0.04	77.32	0.59	77.32	27.68	77.32	40.59
	(57.32)	(1.33)	(57.32)	(1.59)	(57.32)	(25.18)	(57.32)	(52.98)
Storage	12.5	7.14	71.55	93.55	0	4.73	0	42.45
	(15.15)	(6.86)	(88.63)	(93.94)	–	(5.6)	–	(51.67)

Notes. Standard deviations are presented in parentheses. Solar PV and storage capacities are in KWs and KWhs, respectively.

with a battery to reduce MDCs. Coincidental peak MDCs elevate storage investment because the battery can target a relatively limited number of hours and induce large bill reductions.

Under the TOUR rate class, there are limited incentives to invest in storage. The TOUR Proposed Coin. MDC rate class is the exception. This key difference arises for two reasons. First, under the TOUR Proposed tariff, there is larger within-day retail rate price differentials elevating the value of energy storage. Second, the shift to coincidental peak MDCs elevates the value of storage which can be utilized to offset the evening coincidental peak MDCs. Individually, these two incentives are not sufficient to drive investment in storage, but together this drives a sizable amount of investment under TOUR Proposed MDC (above the exogenous storage capacity levels).

Table 8: Average Percentage Change in Total Electricity Costs - Endogenous Investment

Solar PV

Baseline	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
TOUB	-59.17	-0.05	-61.91	-4.05	-91.76	-20.75	-94.18	-37.30
	(5.59)	(0.23)	(6.62)	(10.44)	(9.46)	(7.00)	(9.84)	(16.88)
TOUR	-55.10	-0.05	-57.64	-3.70	-85.42	-19.15	-87.67	-34.97
	(4.09)	(0.23)	(4.98)	(9.55)	(6.91)	(6.31)	(7.25)	(16.03)

Solar PV and Storage

Baseline	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
TOUB	-61.90	-1.95	-71.53	-24.80	-91.76	-21.07	-94.18	-39.30
	(5.41)	(1.19)	(12.96)	(5.53)	(9.46)	(7.19)	(9.84)	(11.93)
TOUR	-57.69	-1.85	-66.75	-23.09	-85.42	-19.44	-87.67	-36.04
	(4.31)	(1.26)	(12.00)	(5.13)	(6.91)	(6.46)	(7.25)	(11.61)

Notes. Standard deviations are presented in parentheses.

Table 8 presents the average percentage change in total electricity costs as we move from a baseline tariff (i.e., TOUB or TOUR) to one of our eight potential tariffs with endogenous DER investment, net of the change that would have occurred absent investment in DER capacity (recall Table 3). In the solar PV only case, we observe the largest bill savings under the existing tariff structures. The bill savings are magnified in the endogenous setting because we observe an increase in PV investment compared to our exogenous benchmark. Similar to the exogenous capacity setting, the shift to proposed tariffs results in a reduction in bill savings. However, in the endogenous capacity investment case, this reduction is magnified because of the limited solar PV investment. In the solar PV and storage setting, bill savings (weakly) increase. The increase is most acute in the TOUB tariff with coincidental peak MDCs which observes a sizable amount of storage investment driven by the incentive to reduce MDCs. The existing tariffs continue to generate large bill savings, while the proposed tariffs generate limited bill savings due to the reduction in solar PV capacity investment and solar output compensation under the new on-peak hours definition.[46]

Next, we investigate the avoided costs by tariff structure and technology. In the endogenous setting, analyzing avoided costs and cost-shifting concerns is complicated by the fact that changes in the tariff structure impacts both the battery charge and discharge decisions, as well as the solar PV and storage capacity investment decisions. While storage investment now varies across tariffs, the storage charge and discharge behavior is identical to the behavior outlined in Section 5.1.

Table 9: Average Avoided Cost ($) - Case 1 with Endogenous Investment

Solar PV	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Total	14,211	0	14,208	666	14,211	5,293	14,211	10,903
	(10,692)	–	(10,694)	(1,737)	(10,692)	(4,791)	(10,692)	(12,175)
Energy	10,935	0	10,933	443	10,935	4,038	10,935	8,458
	(8,053)	–	(8,054)	(1,155)	(8,053)	(3,553)	(8,053)	(9,282)
Capacity	3,276	0	3,275	223	3,276	1,255	3,276	2,445
	(2,990)	–	(2,990)	(583)	(2,990)	(1,348)	(2,990)	(3,127)
Solar PV and Storage	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Total	14,297	103	15,439	1,545	14,211	5,228	14,211	8,270
	(10,846)	(277)	(10,458)	(1,794)	(10,692)	(4,819)	(10,692)	(9,412)
Energy	10,936	82	9,963	304	10,935	3,908	10,935	5,785
	(8,054)	(219)	(6,989)	(298)	(8,053)	(3,560)	(8,053)	(7,377)
Capacity	3,361	22	4,476	1,242	3,276	1,320	3,276	2,485
	(3,118)	(62)	(3,857)	(1,613)	(2,990)	(1,355)	(2,990)	(2,311)

Notes. Standard deviations are presented in parentheses. Energy avoided costs includes wholesale energy, line losses, ancillary services, and environmental compliance costs. Capacity avoided costs include capital costs of generation, transmission, and distribution infrastructure.

Table 9 illustrates the average avoided costs by tariff and technology with endogenous investment for Case 1.[47] Unlike the exogenous setting, there is now variation in the average avoided costs

[46]Table B.7 in the Appendix presents the Net Present Value (NPV) calculations by Tariff and Technology. The NPVs are large and positive under the existing tariffs structures. The TOUR tariff generates the largest NPVs. Alternatively, the move to proposed tariffs results in a sizable reduction in the NPVs.

[47]While Case 2 elevates the avoided cost values, the qualitative conclusions are analogous to Case 1 presented below.

in the solar PV only setting due to the presence of variation in solar PV capacity across tariffs. The average avoided costs are approximately equal under the existing tariffs because solar capacity is identical across these cases. A shift to the proposed rates results in a substantial reduction in average avoided costs because we observe a large decline in solar PV investment. In fact, we observe approximately zero avoided cost in the TOUB Proposed rate class because of the limited solar investment. The addition of coincidental peak MDCs restores a portion of the avoided costs under the proposed rates because of the higher amount of solar capacity investment.

The results with endogenous solar PV and storage systems continue to illustrate that the existing tariffs result in the largest average avoided costs. A shift to the proposed tariffs decreases average avoided costs because capacity investment decreases. This effect continues to be most pronounced under the TOUB Proposed tariff. The increase in avoided capacity-related costs is largest in the presence of coincidental peak MDCs because storage capacity investment increases and the battery is discharged in system constrained hours. The addition of coincidental peak MDCs in the proposed tariffs elevates avoided costs due to increased investment in solar and storage, but it remains lower than the existing tariffs due to the overall reduction in solar PV capacity.

Somewhat surprisingly, Panel B illustrates that the addition of storage capacity can reduce the average avoided total cost level under the TOUR Proposed rates. The ability to invest in storage capacity (weakly) reduces solar PV capacity because the battery is utilized to offset MDCs which was a driver for solar PV investment when storage was unavailable. The reduced investment in solar results in a sizable reduction in avoided energy costs. While the addition of storage capacity elevates avoided capacity-related costs, this increase is not sufficient to offset the reduction in avoided energy costs. A key objective in the shift in on-peak hours to later in the evening was to better reflect system constraints in retail prices. However, the endogenous capacity investment results demonstrate that the level of avoided costs can decrease in the proposed tariffs because of the reduced investment incentives in solar PV capacity. This effect dominates potential improvements in the charge and discharge incentives of battery storage that can arise due to the better alignment of on-peak prices and system constraints (recall Section 5.4 and Table 5).

Finally, we compare the avoided costs to the bill savings to investigate variation in the cost-shifting measure by retail tariff. In the endogenous setting, two sources of variation drive differences in the cost-shifting measure. First, as demonstrated in the exogenous capacity setting, each tariff structure motivates different battery charge and discharge incentives and total bill savings. Second, as shown in Table 7, investment incentives differ substantially by the tariff structure.

Table 10 Panel A demonstrates that the cost-shifting measure is systematically positive under the existing tariffs (TOUB and TOUR) in the solar PV only setting. Similar to the exogenous case, cost-shifting concerns are highest under TOUR tariff with high midday volumetric prices. The shift to proposed tariffs substantially reduces the cost-shifting measure. This is driven primarily by a reduction in solar PV investment. When coincidental peak MDCs are imposed, cost-shifting concerns are elevated due to increased solar investment, but the average cost-shifting measure

Table 10: Cost-Shifting by Technology and Tariff - Case 1 with Endogenous Investment

Panel A: Average Cost-Shifting Measure with Solar PV

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
$	2,087	0	2,834	47	11,014	87	11,719	1,049
	(2,378)	–	(2,660)	(124)	(8,400)	(678)	(9,018)	(1,782)
$/KW	25.61	0	35.28	15.05	141.11	4.21	149.65	14.42
	(24.62)	–	(18.13)	(1.25)	(24.68)	(25.06)	(22.46)	(20.29)
$/KWh	0.010	0	0.014	0.006	0.058	0.002	0.061	0.006
	(0.010)	–	(0.007)	(0.001)	(0.010)	(0.010)	(0.009)	(0.008)
# > 0	19	0	22	3	22	10	22	15

Panel B: Average Cost-Shifting Measure with Solar PV Plus Storage

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
$	2,914	483	6,402	5,484	11,014	263	11,720	2,519
	(3,144)	(471)	(6,046)	(5,204)	(8,400)	(755)	(9,019)	(2,711)
$/KW	34.84	–	77.29	146.64	141.11	12.31	149.66	54.08
	(26.84)	–	(38.94)	(15.32)	(24.68)	(28.97)	(22.46)	(44.92)
$/KWh	0.014	–	0.032	0.060	0.058	0.005	0.061	0.022
	(0.011)	–	(0.016)	(0.007)	(0.010)	(0.012)	(0.009)	(0.018)
# > 0	20	22	22	22	22	11	22	19

Notes. Standard deviations are presented in parentheses. # > 0 counts the number of facilities with positive NPVs. $/KW and $/KWh measures the cost-shifting measure in terms of $ per KW and per KWh of solar PV capacity and solar PV output, respectively.

continues to be modest under the proposed tariffs.

Table 10 Panel B demonstrates that the cost-shifting measure (weakly) increases in the presence of storage capacity investment. However, the cost-shifting measure continues to decrease substantially as we move from existing to the proposed tariffs. Similar to the solar PV only setting, this is driven primarily by reduced solar PV investment. The cost-shifting measure continues to increase in the coincidental peak MDC counterfactual tariffs. While these tariffs motivate more storage capacity investment and can increase avoided cost, they also result in larger cost-shifting concerns because the bill savings exceed the increased avoided costs under the existing and proposed tariff structures. This finding parallels the results presented in the exogenous capacity setting.[48]

7 Conclusion

We examine the impact of proposed changes to C&I consumers' retail tariffs in Southern California on investment incentives, avoided electricity network costs, and cost-shifting concerns associated with behind-the-meter solar PV and solar PV plus energy storage systems. In particular, the proposed time-of-use retail rates shift on-peak hours from midday to the evening in an attempt to better align retail prices with network constraints and the costs of providing electricity services.

[48] Table B.8 in the Appendix presents the aggregate cost-shifting measure across all 22 sites in our sample. These results parallel the findings reflected in the average avoided cost measures.

We find that solar PV capacity reduces a consumer's electricity bill substantially under existing tariffs. However, a shift in the on-peak hour definition results in a sizable reduction in the private financial prospects of solar PV systems because higher on-peak prices now arise in the evening hours when solar output is relatively low (or zero). Consequently, investment incentives in solar PV systems decline substantially under the proposed tariffs.

We illustrate that the retail tariff design and on-peak period timing has important impacts on the battery charge and discharge decisions. In particular, we find that the shift in the on-peak period in the proposed tariffs creates incentives to discharge the battery later in the evening hours when the system is more constrained. This elevates the avoided capacity-related costs associated with a battery system under the proposed retail tariff that relies more heavily on volumetric time-of-use prices. However, when a retail tariff places a heavy weight on maximum demand charges (MDCs), the battery discharge decisions are targeted to reduce a facility's private maximum demands. This can lead to the battery being discharged in hours where the overall network is relatively less constrained in the late evening hours reducing the avoided network costs associated with energy storage. We illustrate that a move to impose coincidental peak MDCs that charge for a consumer's maximum demand in system constrained hours can alleviate this mismatch, inducing consumers to discharge the battery in highly network constrained hours.

We find that the incentive to invest in storage is driven primarily by the incentive to reduce MDCs and is limited when retail tariffs place a heavy weight on volumetric rates. Somewhat surprisingly, in the setting with endogenous investment, solar PV capacity investment can decrease when we allow a consumer to also invest in storage capacity under the proposed retail tariffs. This arises because part of the financial driver for investment in solar PV was to reduce MDCs imposed in the early evening hours. The battery now discharges energy to reduce these MDCs. While this is optimal from the consumer's perspective, this can reduce the avoided cost of the DER system.

We also investigated concerns associated with cost-shifting that arises when bill savings exceed the avoided costs of a solar PV or solar PV and battery system. We find that cost-shifting concerns are substantial under existing retail tariffs. This effect is particularly pronounced in retail tariffs with high volumetric retail rates. Alternatively, the cost-shifting measure is considerably lower under the proposed retail tariffs that shift the on-peak period to the evening hours and under retail tariffs with a heavier weight placed on MDCs (and lower volumetric prices). While storage systematically increases avoided costs, it can also elevate cost-shifting concerns.

Our analysis demonstrates that a shift in on-peak hours to better align time-of-use prices with system constraints in the proposed tariffs may not necessarily increase the absolute level of avoided costs associated with a solar PV or solar PV plus storage for two reasons. First, the retail rate design components can lead to the battery being discharged to avoid a consumer's private peaks in consumption to avoid MDCs. Second, we illustrate that investment incentives in solar PV decline considerably under the new proposed tariffs because of the reduction in midday retail prices. However, we find that the proposed tariffs reduce cost-shifting concerns that arise because of high solar PV compensation in the midday hours. This lessens concerns that utilities will be unable to recover their fixed costs of providing network services in the face of growing DER penetration.

Our analysis highlights the nuances that can arise when designing regulated retail rates in the presence of solar PV and storage systems. Tariffs with a heavier weight on MDCs and lower volumetric rates can reduce cost-shifting concerns and motivate investment in behind-the-meter energy storage. However, the imposition of MDCs can reduce solar PV investment and induce consumers to target private maximum demands limiting avoided costs and the reduction in a facility's peak demand during system constrained hours. Imposing coincidental peak MDCs can motivate consumers to target battery discharge decisions in system constrained hours. These findings contribute to the ongoing debates over whether or not to make MDCs a mandatory feature of retail tariffs (e.g., see Hledik (2014); NCCETC (2017)).[49] More broadly, our analysis highlights the trade-offs between elevating avoided costs and reducing cost-shifting concerns when the regulator is restricted in its ability to set more granular retail rates to align price signals with the underlying costs of providing utility services in the face of growing DER penetration.

Our analysis suggests several directions for future research. First, we focused on variation in avoided costs by California's Climate Zones. However, recent research demonstrates that there is substantial variation in the value and costs of integrating DERs at a more granular local level.[50] Future research should investigate the interaction of retail rate design and the operation of DERs utilizing more location-specific avoided cost data. Second, C&I consumers may respond to adjustments in time-of-use rates by changing their consumption behavior. Future research should investigate how consumers responded to the change in California's time-of-use tariffs.[51]

Third, we focused on a fixed solar PV technology in our analysis. Future research should push our methodology further by considering alternative solar PV and battery technologies and configurations (e.g., west-facing solar panels). Fourth, we focused on existing and proposed time-of-use tariffs, as well as counterfactual tariffs that imposed coincidental peak MDCs. While more granular time- and location-specific tariffs have yet to receive wide adoption in practice, a detailed analysis of the interactions between the investment and operation of DERs, avoided costs, and cost-shifting concerns under these alternative tariffs warrants formal investigation.[52] Fifth, future research should consider the interaction between retail rate design and environmental emissions in the presence of behind-the-meter solar PV and battery storage investment.

[49] The importance the design of MDCs was emphasized in the CPUC's DER Action Plan (CPUC, 2017a).

[50] Cohen and Callaway (2016) and Cohen et al. (2016) utilizing detailed data in California to demonstrate the presence of substantial location-specific avoided costs associated with rooftop solar.

[51] We carry out comparative statics that includes peak to off-peak load shifting of up to 6% from baseline consumption levels. We find that our conclusions are robust to these behavioral changes in consumption. See the Technical Appendix for details.

[52] Numerous jurisdictions are advocating for increased temporal and spatial variation in retail tariffs for DER consumers (Biggar and Reeves, 2016; CPUC, 2017a). However, ongoing debates illustrate the complexity associated with moving towards these more cost-reflective tariff structures (e.g., see CPUC (2017b).

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Appendix

A Optimization Program

We describe the central features of the optimization program. We define the fully endogenous model in DER-CAM. The choice variables reflect the level of solar capacity, battery capacity, and optimal charge and discharge decisions of the battery. In the exogenous capacity setting, the optimization program chooses the optimal charge and discharge decisions for a given energy storage system. For a detailed treatment of the optimization program, see Cardoso et al. (2017).
Notation:

- General Notation:
  - h: hour $\{1, 2, ..., 24\}$;
  - m: month $\{1, 2, ..., 12\}$;
  - d: day type $\{1, 2, 3\}$
  - s: season {winter, summer}
  - p: period of the day (on-peak, mid-peak, off-peak);
  - NonCoin: Non-coincidential hours of the day;
  - Coin: Coincidental hour(s) of the day;
  - PV: denotes the Solar PV Technology;
  - ES: denotes Energy Storage Technology;
  - j: denotes all technologies (PV $\cup$ ES);
- Demand Parameters
  - $load_{m,d,h}$: consumer demand at time m, d, h [KW];
  - $UL_{m,d,h}$: electricity purchased from utility at time m, d, h [KW]
- Retail Rate Structure
  - $TE_{m,d,h}$: tariff for electricity consumption at time m, d, h [$/KWh];
  - $TEx_{m,d,h}$: tariff for electricity export at time m, d, h [$/KWh];
  - $MDC_{m,p}$: maximum demand charge for month m and period p [$/KW];
  - $MDCCoin_m$: Coincidential Maximum Demand Charge for month m [$/KW];
  - $MDCNonCoin_m$: Non-Coincidential Maximum Demand Charge for month m [$/KW];
  - TF_m: Fixed Charges for month m [$];
- Technology-Specific Parameters:
  - FCC_j: fixed capital cost of technology j [$];

- VCC_j: variable capital cost of technology j [$/KW];
- $VCSC_{ES}$: variable capital cost of Energy Storage [$/KWh] ;
- OMF_j: fixed annual Operation and Maintenance Cost of technology j [$/KW];
- Lt_j: Lifetime of technology j;

- Other Parameters:
  - An_j: annuity factor for investment in technology j;
  - $GS_{PV,m,d,h}$: PV electricity exported in time m, d, h [KW];
  - $GU_{PV,m,d,h}$: PV electricity generated to be used on-site in time m, d, h [KW];
  - SCE_{ES}: Charging efficiency of storage [%];
  - SDE_{ES}: Discharging efficiency of storage [%];
  - SPE_{PV}: peak solar conversion efficiency [%];
  - $SRE_{PV,m,h}$: solar radiation conversion efficiency in month m and hour h [%];
  - $SI_{m,d,h}$: solar insolation at time m, d, h [KW/m^2];
  - ϕ_{ES}: losses due to decay/self-discharge in ES [%];
  - MSC_{ES}: minimum state of charge [%];
  - IR: interest rate on investments [%];

- Decision Variables:
  - CAP_j: rated output of generation technology j; [KW]
  - $ECAP_{ES}$: energy capacity of energy storage; [KWh]
  - Pur_j: binary purchase decision of technology j; [{0,1}]
  - $SIn_{ES,m,d,h}$: energy input to storage at time m,d,h [KW];
  - $SOut_{ES,m,d,h}$: energy supplied by storage at time m,d,h [KW];
  - $SOC_{ES,m,d,h}$: state of charge of storage at time m, d, h [KWh];

Objective Function. Minimize Total Cost choosing the level of solar capacity, battery capacity, and optimal charge and discharge decisions of the battery.

$$C = \sum_m TF_m + \sum_m \sum_d \sum_h UL_{m,d,h} \cdot TE_{m,d,h} + \sum_m \sum_p MDC_{m,p} \cdot max\left(UL_{m,(d,h)\in p}\right)$$

$$+ \sum_m MDCNonCoin_m \cdot max\left(UL_{m,d,(h)\in NonCoin}\right) + \sum_m MDCCoin_m \cdot max\left(UL_{m,d,(h)\in Coin}\right)$$

$$+ \sum_j \left\{ [FCC_j \cdot Pur_j + VCC_j \cdot CAP_j] \cdot An_j + CAP_j \cdot OMF_j \right\} + VCSC_{ES} \cdot ECAP_{ES} \cdot An_{ES}$$

$$-\sum_m \sum_d \sum_h GS_{PV,m,d,h} \cdot TEx_{m,d,h}. \tag{2}$$

Key Constraints

1. Energy Balance (Supply = Demand).

$$load_{m,d,h} + \frac{SIn_{ES,m,d,h}}{SCE_{ES}} \;=\; SOut_{ES,m,d,h} \cdot SDE_{ES} + GU_{PV,m,d,h} + UL_{m,d,h} \;\; \forall \;\; m,d,h. \tag{3}$$

2. PV output constraint.

$$GU_{PV,m,d,h} + GS_{PV,m,d,h} \leq CAP_{PV} \cdot \frac{SRE_{PV,m,h}}{SPE_{PV}} \cdot SI_{m,d,h} \quad \forall \quad m,d,h. \tag{4}$$

3. Storage charge and discharge operational constraints.

$$SOC_{ES,m,d,h} = SIn_{ES,m,d,h} - SOut_{ES,m,d,h} + SOC_{ES,m,d,h-1} \cdot (1-\phi_{ES}) \quad \forall \quad m,d,h \neq 1; \tag{5}$$

$$SOC_{ES,m,d,h} \geq ECAP_{ES} \cdot MSC_{ES} \quad \forall \quad m,d,h; \tag{6}$$

$$SOC_{ES,m,d,h} \leq ECAP_{ES} \quad \forall \quad m,d,h; \tag{7}$$

$$SIn_{ES,m,d,h} \leq CAP_{ES} \quad \forall \quad m,d,h; \tag{8}$$

$$SOut_{ES,m,d,h} \leq CAP_{ES} \quad \forall \quad m,d,h. \tag{9}$$

4. Annuity factor.

$$An_j = \frac{IR}{\left(1 - \frac{1}{(1+IR)^{Lt_j}}\right)}. \tag{10}$$

B Additional Results and Tables

Table B.1: Southern California Edison's TOU-GS-2 Options B and R (Existing and Proposed)

	TOUB		TOUR	
	(Existing)	(Proposed)	(Existing)	(Proposed)
Energy charge (per kWh)				
Summer on-peak	0.12347	0.12038	0.39519	0.39341
Summer mid-peak	0.08055	0.1136	0.13602	0.13983
Summer off-peak	0.05747	0.07123	0.07077	0.07606
Winter mid-peak	0.07666	0.10381	0.08996	0.1786
Winter off-peak	0.06499	0.07471	0.07829	0.07954
Winter super off-peak		0.05555		0.05655
Non-Coincidental Demand Charge (per kW)	15.89		12	12.1
Time-Specific Demand Charge (per kW)				
Summer on-peak	19.89	18.29		
Summer mid-peak	3.88	0		
Winter mid-peak		3.61		
Total Monthly Fixed Charge[a]	287.44	115.16	287.44	115.16

[a] Total monthly charge is the sum of customer charge, TOU rate meter charge, and single phase service charge.

Table B.2: Southern California Edison's TOU-GS-2 Options B and R Time Periods

	Existing	**Proposed**
Summer months		
Summer on-peak	Weekdays: 12:00 pm to 6:00 pm	Weekdays: 4:00 pm to 9:00 pm
Summer mid-peak	Weekdays: 8:00 am to 12:00 pm; 6:00 pm to 11:00 pm	Weekends: 4:00 pm to 9:00 pm
Summer off-peak	Weekdays: 11:00 pm to 8:00 am Weekends: All hours	Weekdays and Weekends: All hours except 4:00 pm to 9:00 pm
Winter months		
Winter on-peak	N/A	N/A
Winter mid-peak	Weekdays: 8:00 am to 9:00 pm	Weekdays and Weekends 4:00 pm to 9:00 pm
Winter off peak	Weekdays: 9:00 pm to 8:00 am Weekends: All hours	Weekdays and Weekends: 9:00 pm to 8:00 am
Winter super off-peak	N/A	Weekdays and Weekends: 8:00 am to 4:00 pm

Notes. Summer months: June 1st - September 30th. Winter months: October 1st - May 31st.

Table B.3: Comparison of Discharge Incentives by Tariff and Season for the Weekday Day Type

Seasons	Tariff	Non-Coin MDC	On-Peak MDC	On-Peak Marginal Rate	Coincidental Peak MDC
Summer	TOUB		HE: 18	HE: **13**, 14	
	TOUB Proposed		HE: 19, 20, 21	HE: **17**, 18	
	TOUR			HE: **13**, 14	
	TOUR Proposed			HE: **17**, 18	
	TOUB Coin. MDC			HE: **13**, 14	HE: 18, 19
	TOUB Proposed Coin. MDC			HE: **17**, 18	HE: 18, 19
	TOUR Coin. MDC			HE: **13**, 14	HE: 18, 19
	TOUR Proposed Coin. MDC			HE: **17**, 18	HE: 18, 19
Winter	TOUB				
	TOUB Proposed			HE: **17**, 18	
	TOUR				
	TOUR Proposed			HE: **17**, 18	
	TOUB Coin. MDC				HE: **19**, 20
	TOUB Proposed Coin. MDC			HE: **17**, 18	HE: 19, 20
	TOUR Coin. MDC				HE: **19**, 20
	TOUR Proposed Coin. MDC			HE: **17**, 18	HE: 19, 20

Notes. HE denotes the hour endings where the battery discharge occurred. The underlined and bolded hours represent the hours with the highest amount of discharged energy. There are four discharge incentives to: (i) avoid Non-Coincidental MDCs (Non-Coin MDC); (ii) avoid an On-Peak MDCs (On-Peak MDC); (iii) arbitrage on the peak to off-peak rate differential (On-Peak Marginal Rate); and (iv) avoid a coincidental MDCs (Coin. Peak MDC).

Table B.4: Average Avoided Cost by Cost Category, Technology, and Tariff - Case 2

Panel A: Average Avoided Cost by Category and Tariff ($)

Technology	Solar	Solar PV Plus Storage							
		TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Total	11,374	11,658	11,509	11,680	11,729	11,397	11,906	11,673	12,098
	(9,269)	(9,688)	(9,451)	(9,657)	(9,701)	(9,379)	(9,801)	(9,657)	(9,991)
Energy	8,264	8,226	8,303	8,245	8,315	8,223	8,259	8,242	8,276
	(6,506)	(6,464)	(6,537)	(6,476)	(6,544)	(6,464)	(6,507)	(6,476)	(6,514)
Capacity	3,110	3,432	3,206	3,436	3,414	3,174	3,648	3,431	3,822
	(3,027)	(3,443)	(3,128)	(3,398)	(3,357)	(3,166)	(3,548)	(3,398)	(3,722)

Panel B: Average Additional Avoided Cost Due to Energy Storage (%)

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Total	1.76	0.85	2.24	2.55	0.11	3.68	2.17	5.16
	(1.60)	(1.62)	(1.19)	(1.79)	(0.68)	(5.62)	(1.14)	(6.15)
Energy	-0.37	0.39	-0.14	0.57	-0.43	-0.08	-0.16	0.15
	(0.33)	(0.52)	(0.29)	(0.42)	(0.25)	(0.12)	(0.38)	(0.08)
Capacity	10.71	6.59	16.56	17.38	1.14	23.67	16.26	32.41
	(9.77)	(10.98)	(18.04)	(21.58)	(3.06)	(29.00)	(17.85)	(35.58)

Notes. Standard deviations are presented in parentheses. Percentages reflect the percentage change in avoided costs from the Solar PV only setting. Energy avoided costs includes wholesale energy, line losses, ancillary services, and environmental compliance costs. Capacity avoided costs include capital costs of generation, transmission, and distribution infrastructure.

Table B.5: Aggregate Avoided Cost and Cost-Shifting Measure - Case 1

Panel A: Aggregate Avoided Cost ($)

Tech.	Solar	Solar PV Plus Storage							
		TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Total	234,689	238,542	237,610	238,979	240,642	235,046	245,846	238,920	247,694
Energy	180,505	179,654	181,414	180,038	181,622	179,607	180,437	179,989	180,766
Capacity	54,184	58,888	56,196	58,941	59,020	55,439	65,409	58,931	66,928

Panel B: Aggregate Cost-Shifting Measure ($)

Technology	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Solar PV	35,502	-28,170	50,697	2,788	181,824	6,428	194,743	19,454
Solar PV and Storage	63,737	-1,396	84,838	33,349	204,620	21,403	217,639	37,500

Notes. Numbers reflect total annual avoided costs across the 22 sites. Energy avoided costs includes wholesale energy, line losses, ancillary services, and environmental compliance costs. Capacity avoided costs include capital costs of generation, transmission, and distribution infrastructure.

Table B.6: Cost-Shifting by Technology and Tariff - Case 2

Panel A: Average Cost-Shifting Measure with Solar PV

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
$	907	-1,987	1,598	-580	7,558	-414	8,145	178
	(1,746)	(2,342)	(1,683)	(1,287)	(6,127)	(1,620)	(6,630)	(1,421)
$/KW	14.70	-34.15	27.07	-10.49	129.02	-7.93	138.64	1.76
	(30.57)	(29.57)	(21.72)	(22.48)	(30.04)	(29.76)	(26.83)	(26.57)
$/KWh	0.006	-0.014	0.011	-0.004	0.053	-0.003	0.057	0.001
	(0.012)	(0.012)	(0.009)	(0.009)	(0.012)	(0.012)	(0.011)	(0.011)
# > 0	11	6	21	8	22	8	22	9

Panel B: Average Cost-Shifting Measure with Solar PV Plus Storage

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
$	2,082	-772	3,039	726	8,588	241	9,079	865
	(2,641)	(1,989)	(3,144)	(1,845)	(7,059)	(1,649)	(7,470)	(1,741)
$/KW	33.17	-15.52	48.68	9.41	144.68	2.78	152.92	13.00
	(36.36)	(32.94)	(30.50)	(28.79)	(33.97)	(30.86)	(31.56)	(28.88)
$/KWh	0.014	-0.006	0.020	0.004	0.059	0.001	0.063	0.005
	(0.015)	(0.013)	(0.013)	(0.012)	(0.014)	(0.013)	(0.013)	(0.012)
# > 0	18	8	21	10	22	9	22	10

Notes. Standard deviations are presented in parentheses. # > 0 counts the number of facilities with positive NPVs. $/KW and $/KWh measures the cost-shifting measure in terms of $ per KW and per KWh of solar PV capacity and solar PV output, respectively.

Table B.7: Net Present Value by Tariff and Technology - Endogenous Investment

Panel A: Net Present Value with Solar PV

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Mean	25,401	208	35,134	1,717	142,209	1,050	151,437	10,948
	(19,874)	–	(29,391)	(4,512)	(106,763)	(2,102)	(115,332)	(13,346)

Panel B: Net Present Value with Solar PV and Storage

	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Mean	27,997	2,002	43,239	14,352	142,209	1,164	151,437	20,983
	(22,720)	(3,622)	(33,890)	(27,054)	(106,763)	(1,245)	(115,332)	(21,152)

Notes. Standard deviations are presented in parentheses. The NPV under TOUB Proposed for the Solar PV only case reflects the NPV of one facility that invests in positive solar PV output.

Table B.8: Aggregate Avoided Cost and Cost-Shifting - Case 1 with Endogenous Investment

Panel A: Aggregate Avoided Cost ($)

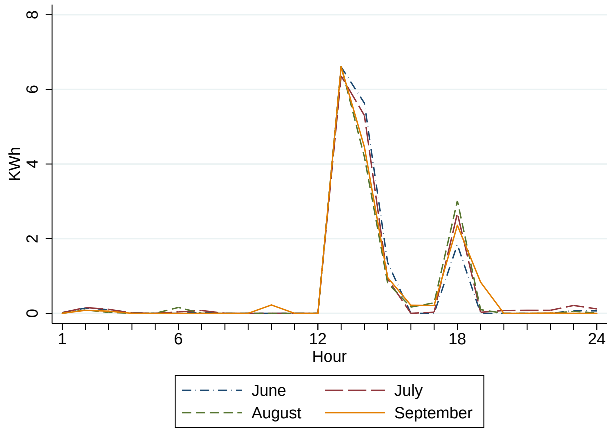
Solar PV	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Total	312,633	0	312,566	14,657	312,633	116,449	312,633	239,861
Energy	240,565	0	240,521	9,748	240,565	88,840	240,565	186,075
Capacity	72,067	0	72,045	4,908	72,067	27,609	72,067	53,786
Solar PV and Storage	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Total	314,532	2,270	295,649	34,000	312,633	115,014	312,634	181,944
Energy	240,588	1,795	210,378	6,683	240,565	85,976	240,566	127,279
Capacity	73,944	475	85,272	27,317	72,067	29,039	72,068	54,665

Panel B: Aggregate Cost-Shifting Measure ($)

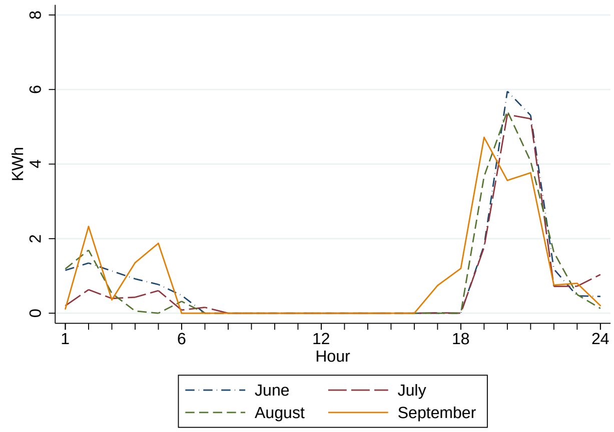
Technology	TOUB	TOUB Prop.	TOUB Coin. MDC	TOUB Prop. Coin. MDC	TOUR	TOUR Prop.	TOUR Coin. MDC	TOUR Prop. Coin. MDC
Solar PV	45,914	541	62,347	1,042	242,301	1,924	257,816	23,086
Solar PV and Storage	64,110	10,632	140,851	120,647	242,301	5,791	257,830	55,410

Notes. Numbers reflect total annual avoided costs across the 22 sites. Energy avoided costs includes wholesale energy, line losses, ancillary services, and environmental compliance costs. Capacity avoided costs include capital costs of generation, transmission, and distribution infrastructure.

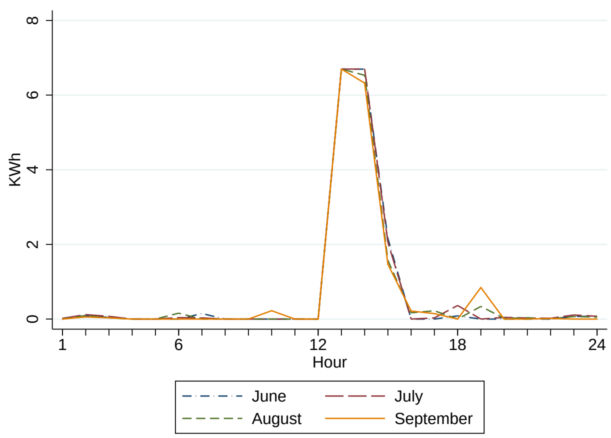
Figure B.1: Battery Discharge Decisions by Tariff Structure for the Summer Weekday Day Type



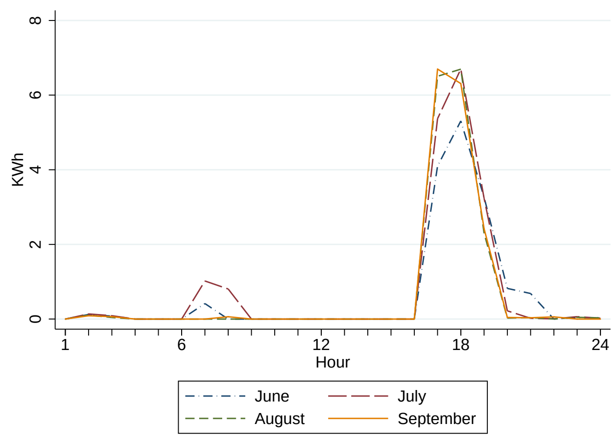
(a) TOUB



(b) TOUB Proposed

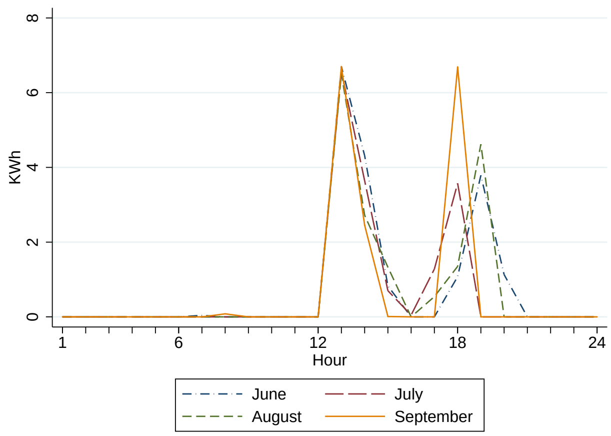


(c) TOUR

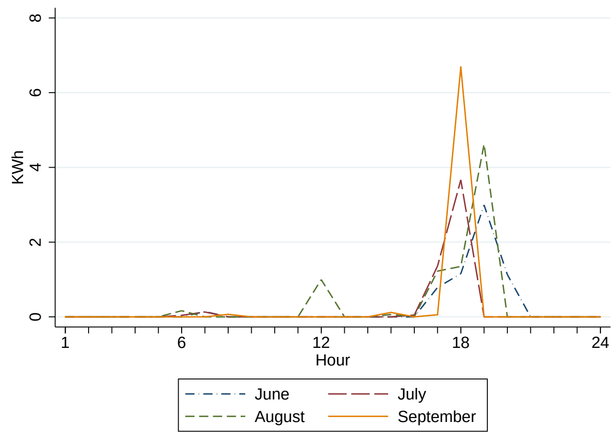


(d) TOUR Proposed

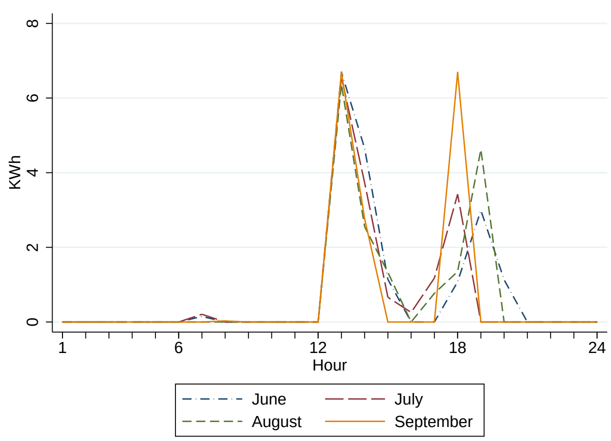
Figure B.2: Battery Discharge Decisions by Tariff Structure for the Summer Peak Day Type



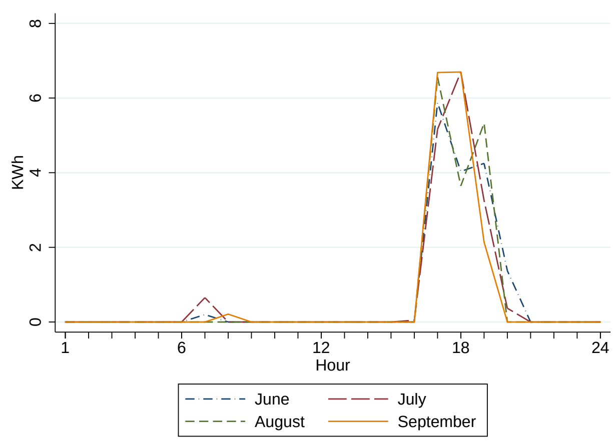
(a) TOUB Coin. MDC



(b) TOUB Proposed Coin. MDC



(c) TOUR Coin. MDC



(d) TOUR Proposed Coin. MDC

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