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Building efficiency, electrification, and distributed solar PV bill savings under time-based retail rate designs

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Executive Summary

Building energy technologies and distributed generation, including energy efficiency (EE), distributed solar PV (DPV), and building electrification, are critical to meeting decarbonization goals. Rate design may play an important role in determining the customer economics of adopting these technologies, but it is unclear whether – and to what extent – current rate design trends support or impede progress toward these goals. In this paper, we answer these questions by quantifying the range of residential customer bill impacts of EE, DPV, and building electrification investments under current and emerging time-based retail electricity rate designs (i.e., time-of-use, event-based pricing, coincident demand charges, and real time pricing). We also compare these customer bill savings to power system and societal benefits and assess how well the investments are compensated relative to the societal value they provide.

The study captures the heterogeneity in customer consumption and bill impacts across customers, rate designs, and technology investments. We calculate changes in customer electricity and energy bills across nearly 40,000 simulated building profiles in four regionally representative utility service territories under flat and time-based rates. These profiles reflect variation in residential building characteristics (e.g., vintage, appliance saturation), climates, and occupant behavior. The study also analyzes heterogeneity across DPV system orientations and EE technology portfolios that vary equipment, lighting, and envelope upgrades.

On average, we find that time-based rates lead to changes in median customer bill savings of less than two percentage points across all EE and DPV investments. We find no consistent directional relationship between EE and DPV customer bill savings under flat and time-based rate designs: in some cases, time-based rates increase bill savings relative to flat rates, while they decrease bill savings in other cases. Although the study results highlight important heterogeneity across customers, investments, rates, and regions, the vast majority of customers experience a change in bill savings smaller than 2% of their total bill, and almost no customers experience a reduction in bill savings greater than 6% of their bill.

Comparing these bill savings to social avoided costs, we find that time-based rates may increase or decrease the economic efficiency of customer incentives to invest in EE and DPV. The differences in the ratios of bill savings to social avoided costs are more pronounced *across* utilities than across rates *within* utilities. We show that the average volumetric rate levels are a stronger predictor of economic efficiency of these investment incentives than the temporal variation in volumetric rates.

Estimated changes in building electrification customer energy bills under flat rates (i.e., energy bills pre- and post-electrification under existing rates) vary noticeably by utility. For some utilities, the substantial energy savings from replacing older equipment with much higher efficiency heat pumps reduce median customer energy bills across all rates. For other utilities, installing building electrification technologies increases median customer energy bills because of the higher price of electricity compared to fossil fuel prices. Even in these cases, we find that the efficiency gains are large enough to save nearly half of the customers money.

We find that time-based rates increase median electrification bill savings across all analyzed regions and rates. However, the changes are consistently smaller than 10% of customers' total bills. We also find minimal impacts of time-based rates on the variation of electrification bill savings across households within the same utility.

We ultimately find that differences in average retail volumetric rates – as either the difference in the average time-based versus the flat rate or the difference in average fossil fuel price versus the average electricity price – drives most of the variation in customer bill savings. This suggests that adjusting the average retail volumetric rate level may be more impactful than changing the temporal variation in volumetric rates for aligning compensation of EE and DPV investments with societal benefits and policy goals. Our study also identifies important tradeoffs in increasing or decreasing the average volumetric electricity rate. For example, lowering the volumetric rate by increasing the fixed charge to reduce building electrification bill impacts can undermine EE and PV bill savings.

We discuss implications for policymakers and areas for future research. First, the risk of substantial bill increases under time-based rates for customers that invest in EE, DPV, and building electrification may be overstated. Second, customers that have invested in EE, DPV, and building electrification may not be financially motivated to enroll in time-based rates, undermining efforts by decision-makers and utilities to encourage load shifting or shedding. Third, adjusting the average retail volumetric rate level may be more impactful than changing the temporal variation in volumetric rates for aligning compensation of EE and DPV investments with societal benefits. Fourth, rate design may be complicated by the desire to incentivize multiple decarbonization technologies, which highlights the importance of setting rates to reflect social marginal costs and using additional incentives for any remaining misalignment in adoption incentives. Finally, our understanding of the effects of changes in retail rate design on customer economics for investments in EE, DPV, and building electrification could be improved by future research that considers additional rate designs, short-run customer price response, and the relative roles of bill savings and equipment investment costs on customer adoption decisions.

1. Introduction

Building energy technologies and distributed generation, including energy efficiency (EE), distributed solar PV (DPV), and building electrification, are critical to meeting state, utility, and U.S. decarbonization and greenhouse gas (GHG) goals (e.g., Williams et al., 2012, Nadel and Ungar, 2019, Langevin et al., 2023). Under current electricity rate designs and declining capital cost trends, adoption and deployment of EE and DPV has substantially increased (Consortium for Energy Efficiency, 2023; Barbose et al., 2023; Davis, 2022). Likewise, there is growing policy interest in building electrification to reduce fossil fuel consumption and take advantage of increasing amounts of power sector renewable energy (e.g., Inflation Reduction Act, 2022). There is also increasing regulatory support for time-based retail electricity rate designs that vary prices by hour to better reflect the time-dependent nature of system costs and encourage more economically efficient consumption (Satchwell et al., 2019).

In practice, residential EE, DPV, and building electrification, often produce a largely static change in customer hourly consumption. Customers frequently cannot readily shed or shift electricity consumption and generation from most EE, DPV, and building electrification technologies in response to time-based rate designs. For example, customers cannot shift the timing of their DPV generation across days or hours of the day, and they generally have no financial incentives to curtail this generation absent pairing solar with storage. Even for programmable thermostats that are intended to facilitate price-responsive behavior, the majority of customers either do not use the programming feature or keep the thermostats in manual modE3e (Pritoni et al., 2015). The transition to time-based rates, therefore, has the potential to enhance or erode bill saving opportunities from these investments depending on the temporal alignment between rate features (e.g., peak and off-peak prices) and energy savings. Given the limitations of EE, DPV, and building electrification to shift the timing of energy savings, the investments may have limited bill savings opportunities, which could impact customer incentives to adopt these critical GHG-reducing technologies and risk undermining climate goals.

In order to assess whether time-based rates will enhance or erode customer bill savings, we quantify the range of residential customer bill impacts of EE, DPV, and building electrification investments under current and emerging time-based retail electricity rate designs (e.g., time-of-use, event-based pricing, coincident demand charges[1], and real time pricing) to identify the least and most beneficial PV system orientations and EE/electrification measures from the customer perspective. We also compare EE and DPV customer bill savings to power system and societal benefits and assess how well the investments are compensated relative to the societal value they provide (i.e., whether EE and DPV customer technologies over- or under-incentivized).

[1] We specifically include coincident demand charges as a time-based retail electricity rate design in this study because we model one based on consumption during a specific time period and intended to collect demand-driven and demand-allocated costs. Other demand charge designs may not be based on time-based consumption and/or time-based costs.

Importantly, the study explores a large number of differences in utility retail rate designs, EE, and building electrification measures, DPV system designs, and geographic locations that are key drivers of customer bill savings and marginal costs. We calculate residential electricity and non-electricity bill savings across different EE and building electrification measure packages and DPV system orientations under 12 actual utility price schedules in four utility service areas.[2] We use the National Renewable Energy Laboratory (NREL)'s ResStock simulations of residential building end-use consumption to capture the heterogeneity in these results across households due to differences in vintage, size, construction practices, installed equipment, appliances, and climate. Specifically, we consider four different packages of building measures: electrification equipment replacement paired with equipment efficiency upgrades (e.g., cooling, water heaters, and washers); building envelope upgrades; lighting efficiency upgrades; and general equipment efficiency upgrades. We use NREL's System Advisor Model to estimate hourly DPV system production using three different system orientations: south-, southwest-, and west-facing.

To capture a variety of climates and power system conditions, we analyze EE, DPV, and building electrification investments that represent four different geographic and climate regions: the Southwest, Great Plains, Midwest, and Northeast. We chose four regions where residential time-based rates are currently offered, based on our review of electricity rates available as of 2019, that also introduce diversity in customer hourly consumption to our analysis.

We analyze a range of residential retail electricity rate designs presently offered in these four regions and categorize them based on having one or more of five attributes: 1) "flat" rates that are time-invariant or vary only by season; 2) time-of-use (TOU) $/kilowatt-hour (kWh) rates that vary systematically by season, hour of day, and whether the day is a non-holiday weekday; 3) rates with coincident $/kilowatt (kW) demand charges where customers pay each month based on their maximum kW demand during certain hours of the day; 4) event-based rates that have higher prices during a small number of hours of the year when there is especially high system demand; and 5) real-time rates that change price dynamically based on day-ahead market conditions.

We also estimate the power system and societal benefits of each EE and DPV investment and analyze whether bill savings move further or closer to these societal benefits with time-based rates. These include all utility system costs avoided due to reductions in the quantity of electricity generated and delivered, the generating capacity reserved for grid balancing, the renewable generation procured to meet policy standards, and investments in new generation or distribution capacity. We also include reductions in the external costs associated with carbon emissions and criteria pollutants from electricity generation. These avoided cost calculations closely follow Borenstein and Bushnell (2022a) and the 2019 Energy and Environmental Economics, Inc. (E3) Avoided Cost Calculator (ACC).

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[2] Although we estimate bill savings using actual price schedules from utilities in these regions, we use simulated customer load shape data and estimated marginal costs to calculate bill impacts and other economic metrics. As such, results based on our generic utility modeling approach are not intended to represent actual bill impacts for the utilities in our study and should not be interpreted as suggesting the rates used in our study are not just and reasonable.

The study provides the most comprehensive analysis to date of the impact of time-based retail electricity rate designs on households' incentives to adopt GHG-reducing technologies. There is a small existing body of literature in this area; however, most of the case studies are restricted to one location and technology and analyze only one or two time-based rates. For example, Liang et al. (2021) compared bill savings from air conditioning in Arizona under a TOU rate and an increasing block rate. Borenstein (2007) similarly compared bill savings from PV under a TOU rate and an increasing block rate. Sergici et al. (2023) considered two types of TOU rates and analyzed bill savings from heat pumps for 80 customers in an unnamed utility service territory. In contrast, we consider 12 different EE technologies, six building envelope efficiency upgrades, three DPV system orientations, four building electrification measures, and 12 different rate designs for 39,553 simulated households in four different geographies. The richness of these data allows us to uncover patterns and important drivers of heterogeneity in customer energy bills.

In addition, we employ novel social marginal cost estimation methods to explore implications for economic efficiency. Of the aforementioned rate design studies, only Liang et al. (2021) compared bill savings to marginal social avoided costs. We improve on these estimates in several ways. First, we leverage Borenstein and Bushnell (2022a) to estimate the marginal costs of carbon dioxide and criteria pollutant emissions due to electricity generation. Relative to older estimates, the resulting values better reflect the type of generation displaced by a reduction in energy use in a specific hour and location. Second, we follow Borenstein and Bushnell (2022a) and use marginal estimates of distribution losses as opposed to average estimates. Third, we consider state renewable energy policies and deferred distribution and generation capacity investments in the avoided cost calculations. With these changes, our estimates better reflect the variation in social marginal costs over hours of the year, with relatively higher marginal costs during periods of high demand.

The study also advances the literature on the impacts of building electrification on customer energy bills by considering both the switch from fossil-based to electrical consumption and the influence of corresponding efficiency improvements. Other research has often ignored the coupling of electrification and efficiency. For example, Davis (2022) focused on the electrification of new buildings and calculated the costs of electric technologies relative to highly efficient fossil-based technologies. In contrast, we analyze retrofits and consider efficiency gains from retiring older, less efficient appliances.

This remainder of this study proceeds as follows: Section 2 outlines our analytical approach. Section 3 presents the results of our analysis. Section 4 concludes with a discussion of results and policy implications.

2. Analytical Approach

We quantify the range of customer bill impacts of EE, DPV, and building electrification investments under basic (i.e., flat, average) and time-based retail electricity rate designs. Our analytical approach proceeds in three steps (see Figure 1). First, we derive hourly load shapes for EE and building electrification measure packages and common DPV system orientations. Second, we estimate customer bills for each combination of measures and system orientations under basic and alternative time-based residential retail electricity rate designs that reflect a range of emerging design elements. We also estimate hourly social marginal avoided costs that include power system and environmental costs. Third, we multiply the first two steps on an hourly basis to derive changes in customer energy bills and marginal system benefits. We describe each step in more detail below.

Figure 1. Analytical approach steps

2.1 Determining EE, DPV, and building electrification load shapes

We use NREL's ResStock database[3] to generate hourly baseline energy usage based on simulated building characteristics. We generate hourly shapes for current building technology deployment and appliance stock, as well as for alternative technology deployment scenarios intended to represent increased EE and building electrification. Importantly, ResStock produces a representative sample of buildings across climate zones with a realistic diversity of building types, vintages, sizes, construction practices, installed equipment, and appliances. The hourly load shapes come from a physics-based simulation model that is calibrated and validated using empirical data on actual energy use in buildings, including metered utility data from more than 2.3 million customers throughout the country and circuit-level sub-metered data (Pigman et al., 2022; Wilson et al., 2022). NREL provided custom-generated annual hourly profiles for approximately 10,000 residential buildings per upgrade scenario using 2019 Actual Meteorological Year (AMY) weather data, which represents the most recent year where data are available.

ResStock combines information about the existing appliances and building characteristics with commercially-available energy efficient and electric alternatives to model feasible upgrade packages. We select four of these packages to generate four different sets of building load shapes for our analysis:[4]

[3] Available at: https://resstock.nrel.gov/

[4] See APPENDIX B for detailed information on the specific measures and upgrades assumed in each of these upgrade packages.

- Electrification: The building electrification package replaces non-electric space and water heating with efficient electric alternatives, including heat pump water heaters and heat pumps for space heating and cooling (both ducted and mini-split systems), and also replaces non-electric clothes dryers and cooking ranges.[5] The package also includes improved ducting and energy efficiency upgrades of existing electric appliances, including clothes dryers and cooking ranges. For this package, we include all buildings with at least one non-electric end use in the baseline.
- Equipment: The equipment package replaces existing electric air conditioning, space heating, water heating, refrigerators, clothes washers and dryers, and cooking ranges with more energy efficient alternatives.[6] For this package, we only include buildings with all electric end uses in the baseline.
- Envelope: The envelope package improves attic and exterior wall insulation and adds exterior storm windows. We include all buildings in the baseline.
- Lighting: The lighting package replaces all existing light bulbs with light-emitting diodes (LEDs). For this package, we only include buildings with either incandescent or CFL lighting in the baseline. In ResStock, buildings are modeled as having one lighting type present (i.e., entirely incandescent, CFL, or LED).

We calculate energy savings by taking the difference in annual electricity consumption between each upgrade package and the baseline profile and dividing by the total baseline profile consumption per building.

Using engineering-based estimates of energy efficiency savings has its limitations. Researchers have shown that realized EE savings are sometimes much lower than predicted savings from engineering estimates (Davis et al., 2014; Levinson, 2016; Allcott and Greenstone, 2012; Fowlie et al., 2018; Christensen et al., 2021). However, our key results focus on the hourly shape of EE savings as opposed to the absolute level of savings. Therefore, our results will still be accurate if prediction error in savings is proportional to actual realized savings across hours.

For DPV generation shapes, we use residential rooftop generation data from NREL's System Advisor Model (SAM).[7] We consider three potential PV orientations: south-facing, southwest-facing, and west-facing. Regardless of orientation, we assume all households size their PV systems to offset their annual electricity usage[8], so the implied system capacity varies with orientation. We select one PV generation shape for each utility service area and PV system orientation. We model solar production using 2019 AMY weather data for consistency with the ResStock AMY.

[5] Heat pumps in the electrification package may result in an increase in cooling load for buildings without pre-existing air-conditioning.

[6] While buildings receiving the equipment upgrade package will generally exhibit a decrease in electricity consumption, they may show a net increase in total electricity consumption in cases where existing space heating is replaced by heat pumps for buildings without pre-existing air conditioning.

[7] Available at: https://sam.nrel.gov/

[8] We note this is a simplifying assumption and does not consider available roof area.

2.2 Selecting retail electricity rate designs and calculating bill savings

We focus the analysis on a diverse set of commonly-offered residential retail electricity rate designs to capture variation in outcomes under realistic implementations of time-based rates. Although the shift to time-based rates primarily aims to better align prices with temporal variation in costs, designing any utility rate involves balancing accounting and policy objectives and considering the perspectives of many different stakeholders. As a result, time-based rates may differ substantially from social marginal costs in practice and may vary considerably across utilities.

We select ten time-based residential retail electricity rates that were available to customers in 2019 and represent a variety of rate design elements in four different regions: the Southwest, Great Plains, Midwest, and Northeast. This variety enables us to capture heterogeneity in time-based rate impacts due to real-world differences in rate design perspectives and practices. We use publicly available tariff data for utilities in each region and include all applicable tariff charges: volumetric energy and demand charges, fixed charges, additional energy supply charges, sales tax, and other adjustment charges (e.g., cost recovery, program fees, cost sharing).

For the Midwest utility, we select a real-time price (RTP) rate that dynamically updates each day based on forecasted hourly costs. For the Southwest utility, we select two time-based rates. The first is a time-of-use (TOU) rate with a higher $/kWh rate in the late afternoon and early evening “on-peak” period than the rest of the day and an especially low $/kWh rate midday in the winter. The other selected Southwest utility rate has a volumetric ($/kWh) TOU component and a monthly coincident demand charge ($/kW) based on a customer’s highest kW usage during the on-peak period. We select three time-based rates for the Northeast utility, specifically: a TOU rate that has relatively high prices in the afternoon and evening; an event rate that has a very high price for up to ten event days a year during the afternoon and evening; and a TOU + event rate with both TOU and event pricing components. Finally, we select a TOU and an event rate for the Great Plains utility.[9] The TOU rate has a relatively high price on summer afternoons and early evenings. The event rate uses the same on-peak period, but on-peak price is set dynamically, where one of four prices are set based on the average day-ahead wholesale electricity price during those hours. In the winter, the Great Plains utility TOU and event rates have declining-block schedules where the marginal price decreases after a customer uses 600 kWh in a month.

The defining feature of a time-based rate is that prices differ depending on when within the billing period electricity is consumed. We generate an hourly profile (i.e., 8,760 data points) for each time-based rate in the study that includes the volumetric rate ($/kWh) applicable in each hour and season and, when present, demand charges ($/kW). The Northeast utility’s critical peak pricing tariff includes a critical price applicable in the top-ten demand periods, and we use the baseline aggregate residential building load profile for Northeast utility hourly load shapes to determine which ten days have the

[9] The Great Plains utility describes the event rate as a “variable peak pricing” rate. We categorize both “variable peak pricing” and “critical peak pricing” as “event” rates because they include a distinct price for “critical events” that are applicable to periods when demand is in excess of the “peak” rate level.

highest peak load. For the Great Plains utility variable peak pricing schedule, we determine the on-peak price by using 2019 day-ahead locational marginal pricing (LMP) data from the pricing node for Oklahoma Gas and Electric (OGE). We also use 2019 day-ahead LMP data from a pricing node in Ameren Illinois territory for the real-time portion of the Midwest utility RTP rate.

Figure 2 shows the six TOU rates (without event-based elements) in our study by hour and season, and Table 1. Study TOU rate peak-to-off peak ratios for the generic utilities

shows the TOU rate peak-to-off peak ratios. Notably, all but one of the TOU rates in the study have a peak-to-off peak ratio less than two. Figure 3 shows average prices for the four event and real-time pricing rates by hour of day for four sample months.[10] These average values capture seasonal trends and systematic variation over hours of the day, which is useful for understanding coincidence with energy savings from EE, DPV, and electrification. The actual values will vary from day-to-day and year-to-year due to the number and timing of events called.

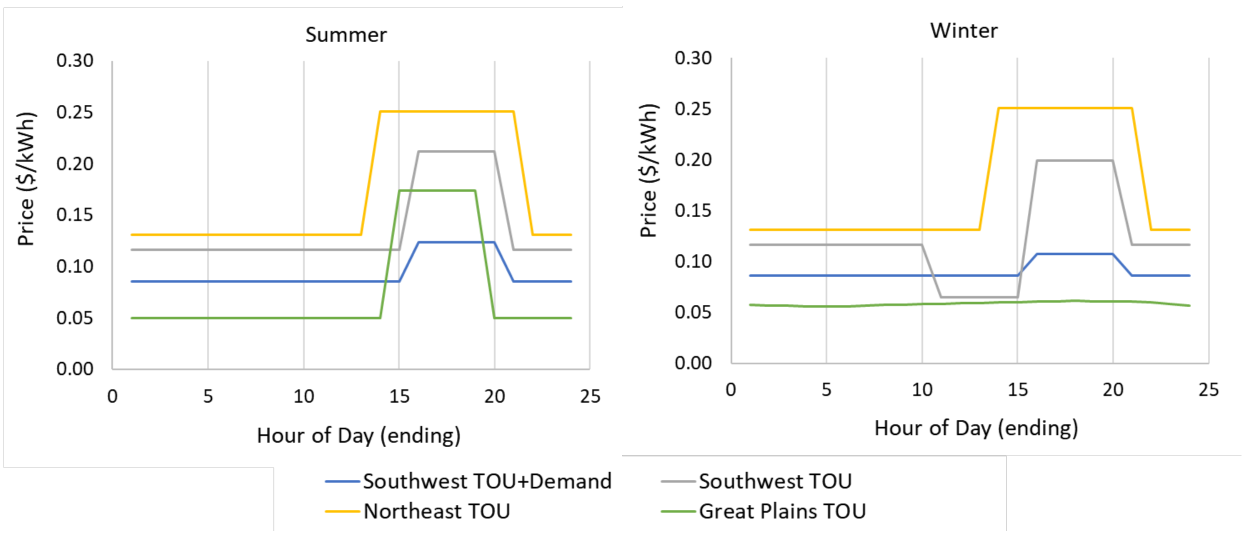

Figure 2. Average time-of use rate prices by hour and season for the generic utilities

Table 1. Study TOU rate peak-to-off peak ratios for the generic utilities

	Southwest TOU+Demand[11]	Southwest TOU	Northeast TOU	Great Plains TOU
Peak-to-off peak price ratio	1.5	1.9	1.9	3.6

[10] We apply the electricity rates provided in the utilities' 2019 tariff sheets to create hourly pricing schedules for each hour of the year for each tariff type, including tiered pricing based on each customer's load profile. Figure 2 and Figure 3 show average prices calculated using the average electricity price for each hour in a representative month (January for Winter and July for Summer). Where time-of-use schedules do not vary by day for each season, Figure 3 shows variation in price from electricity rates affected by locational marginal pricing.

[11] The Southwest utility TOU+Demand charge rate layers a demand charge on top of the peak price. We show only the TOU peak-to-off-peak ratio here without the additional demand charge layered on top as it is based on consumption in a specific hour each month.

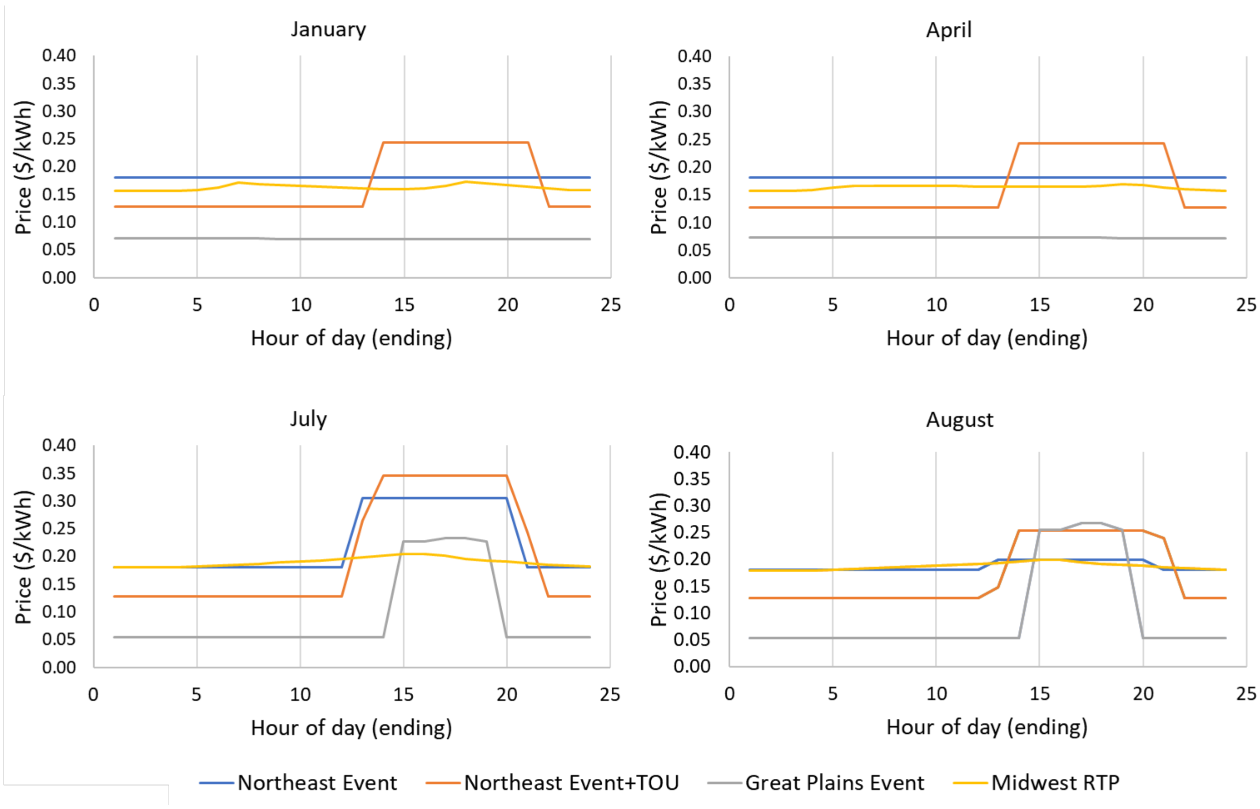

Figure 3. Average prices by hour and month for event and real-time pricing rates for the generic utilities

We use the current residential default retail rate design for each utility as a comparison point for calculating customer bill changes under time-based rates. All of the default rates are two-part tariffs with fixed monthly charges and variable electricity ($/kWh) charges. In the Southwest[12] and Northeast utilities, the default rate schedule has one electricity price that is constant throughout the year. In the Midwest utility, electricity prices vary by season: one electricity price for the summer months (June-September) and a different electricity price for the other (i.e., "winter") months. In the Great Plains utility, the default rate schedule has a declining block design in the winter and an inclining block design in the summer after they use 1,400 kWh in a month. For simplicity, we refer to all of these rates as "flat" since they do not vary by time of day. See APPENDIX E for summary statistics of all the rate schedules used in the analysis.

The time-based and default rates often differ in their $/month fixed charge components as well as their variable $/kWh rate components. All of the rates we analyze include a fixed charge ($/month) that cannot be avoided by changing electricity usage. A higher fixed charge is often accompanied by lower average volumetric rates, which may reduce bill savings regardless of the time-based nature of the rate. Among our sampled rates, fixed charges increase for the Midwest utility and many Northeast utility

[12] Customers are charged one of three energy prices for the Southwest utility's default rate schedule (flat) based on their average monthly energy consumption. We assign all customers the highest consumption tier since the majority of buildings fall into this range for all packages.

time-based rates and decrease for the Southwest utility time-based rates relative to the default utility rates. See Table E-1 in Appendix E for detailed information about fixed charges.

We calculate bill savings under two assumptions about these $/month fixed charges. First, we calculate bill savings using the rates defined in the utility tariff sheets, which include differences in fixed charges across flat and time-based rates. Second, we estimate the bill savings that would occur if each utility's time-based rates used the same $/month fixed charges as the default flat tariff. The first approach reflects bill savings under real-world implementations of time-based rates, which historically have often included changes in the average $/kWh variable rate levels. The second approach isolates the impact of the time-based nature of the $/kWh variable rates. We calculate these counterfactual bill savings by first estimating the average variable rate level that accompanies a $1 change in the fixed charge and then adjusting bill savings by the product of this estimate, the fixed charge change, and kWh electricity savings. See APPENDIX A for a detailed description of this estimation method. We show results using the first calculation approach throughout the paper, and we also include normalized results when the results differ substantially by approach. All results that do not explicitly specify the use of normalized fixed charges use the first calculation approach.

EE customer bills are the product of the hourly load shape and price given the applicable rate design and summed on an annual basis and for each of the upgrade packages in isolation. Similarly, building electrification customer bills are the annual sum-product of the hourly load shape and price given a particular rate design. Importantly, however, we calculate total customer *energy* bills for the building electrification package by multiplying the ResStock electric and non-electric building load shapes by the applicable electric and non-electric (i.e., propane, natural gas, and/or fuel oil) prices.

The ResStock profiles are static and not assumed to be price-responsive. Our study assumption of perfectly inelastic demand is intended to focus on the technology-induced bill savings and does not account for behavioral changes in customer electricity consumption.[13] We expect bill savings inclusive of behavioral response for time-based rates to differ from our estimates and that bill savings may be higher or lower depending on whether the technologies we model make customers more or less price-responsive.[14]

DPV customer bills are calculated by multiplying the retail rate by hourly self-consumption of DPV generation for each building modeled in ResStock. As described previously, each DPV system was scaled so that annual solar generation was equivalent to each individual building's annual electricity profile (i.e., the net electricity load of total annual building consumption and annual DPV generation is equal to zero). We calculate the net profile by subtracting PV generation from customer consumption in each hour. Conceptually, any additional hourly DPV generation in excess of customer consumption would be

[13] Several studies have found that residential demand is inelastic in the short run (Reiss and White 2005, Dutta and Mitra 2017, Deryugina et al. 2020), which suggests that the impacts of relaxing this assumption may be small,

[14] For example, see Satchwell et al. (2020) for a conceptual discussion of interactions between EE and demand response, and EE investments that may make customer more or less likely to shed or shift load depending on the presence of control-enabling technologies and the coincidence of energy savings with customer and utility system peak demands.

treated as exported solar. In practice, the compensation of exported solar varies by state and can range from full retail value to avoided marginal cost (Smith et al., 2021), which has a large potential impact on bill savings and customer adoption of DPV (e.g., Darghouth et al., 2011). For results shown in this paper, we assign no compensation to exported solar in order to focus on the impacts of self-consumption and control for the differences in net metering practices among the four utilities.

2.3 Calculating social marginal avoided costs

We calculate the social marginal costs of a change in residential electricity usage due to EE or DPV. Calculating the marginal costs of building electrification is outside the scope of this analysis as it requires estimating the marginal societal costs of non-electric energy sources (e.g., natural gas, fuel oil, and propane). The social marginal cost calculations in this study closely follow Borenstein and Bushnell (2022a) and the Energy and Environmental Economics, Inc. (E3) 2019 Avoided Cost Calculator (ACC).

Our social marginal costs include two key components: 1) costs ultimately reflected in electricity bills and borne by electricity customers (i.e., ratepayers), and 2) societal costs associated with unpriced emissions from electric generators. Specifically, we model eight marginal ratepayer cost components: energy, transmission congestion, transmission losses, distribution losses, ancillary services, Renewable Portfolio Standard (RPS) policy compliance, and distribution system and generation capacity expansion. [15] To capture societal costs, including costs related to health and climate change, we estimate the external costs associated with carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrous oxides (NO_X), and fine particulate matter ($PM_{2.5}$) emissions from electric generation.

There is some debate about what cost components vary with a 1 kWh change in electricity usage and should, therefore, be included in social marginal costs. In addition, there are vastly different perspectives on the most appropriate magnitudes of some cost component inputs, such as the social cost of carbon (Rennert et al., 2021). Our approach in this paper is to include these cost components and present results broken down by social marginal cost category so that readers can understand the impact of excluding or modifying specific marginal cost components on the results (see APPENDIX C).

We consider an annual snapshot of long-run social marginal costs in 2019. Long-run marginal power system costs reflect the incremental costs of one additional kWh of residential electricity usage when we allow for generator entry, exit, and distribution capacity expansion. Theoretically, a customer considering making a long-term investment in EE, DPV, or electrification would consider the future stream of retail prices across the expected lifetime of the investment. A traditional long-run approach

[15] There are essentially two bookend approaches typically used to estimate avoided transmission capacity costs. One approach is to assume zero avoided transmission capacity costs due to insufficient evidence that transmission costs scale consistent with load growth (e.g., see the San Diego Gas and Electric avoided transmission cost assumption in the 2019 ACC). The other approach is to assume all transmission capacity costs are attributable to incremental load growth (e.g. California Public Utilities Commission's Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M334/K786/334786698.pdf; Austin Energy's 2014 Value of Solar Tariff methodology, available at: https://www.austintexas.gov/edims/document.cfm?id=210805). We take the first approach and do not include transmission capacity costs in order to develop conservative marginal cost estimates.

may compare the present value of this revenue stream to the present value of expected current and future marginal costs. However, this approach would require strong assumptions about customer beliefs and future changes in the power sector. Instead, our snapshot approach considers only the prices in the first year of investment and the marginal costs associated with the generation mix and demand drivers in that year. We can think of these estimates as the best expectations of long-run prices and costs knowing only current conditions. These marginal cost estimates are consistent with the 2019 load shapes, weather, and rates. This snapshot approach does not take into account any future changes to the generation resource mix or any anticipated changes in the marginal value as penetrations of EE and DPV increase. Instead, the approach is appropriate for a snapshot comparison of social marginal costs and 2019 retail rates.

Table 2 summarizes the marginal cost components we include in the analysis, their definitions, and the data sources we use to estimate each component. See APPENDIX C for a more detailed discussion of social marginal cost calculations, the rationales behind the chosen methods, and a summary of the resulting estimates. See APPENDIX D for estimates of correlations between the hourly $/kWh rates and estimated hourly social marginal costs.

We assess the alignment between these marginal societal costs and customer bill savings when investing in EE and DPV to assess whether customers are being over- or under-incentivized for these investments. [16] We measure alignment using the ratio of bill savings to avoided societal costs ("incentive ratio"). An incentive ratio above one suggests that the bill savings from an investment are greater than the societal benefits, and an incentive ratio below one suggests that the bill savings are less than the societal benefits. Importantly, an incentive ratio either greater than or less than one suggests an economically inefficient investment from the societal perspective.[17] If bill savings from EE or DPV are smaller than the societal benefits these investments create, this could lead to underinvestment in these technologies, greater emissions, and higher power sector costs. If bill savings are too high relative to societal costs, this could lead to overinvestment in these technologies, higher bills for other ratepayers, and lower investment in more beneficial technologies and products.

[16] We exclude the electrification package from the societal cost alignment analysis because the marginal societal cost estimates exclude natural gas and other fossil-fuel based system costs. To ensure the bill savings and social cost comparisons reflect the benefits of energy efficiency and DPV, we also restrict this part of the analysis to instances where customers' investments leads them to reduce their energy usage. This results in excluding about 2% and 4% of buildings for the envelope and equipment efficiency package, respectively.

[17] Other perspectives could be considered depending on the marginal costs being considered (e.g., the utility system perspective would only include marginal costs consistent with a utility's revenue requirement).

Table 2. Marginal cost components, description, and data sources

Cost component	Description	Data sources
Energy (incl. transmission congestion & losses)	The location-specific cost of generating a marginal kWh of electricity and transporting it to a given location in the transmission network	FERC Form 714, SNL Financial, Ventyx, ISONE, MISO, SPP, Borenstein and Bushnell (2022a)
Ancillary services	The incremental cost of balancing electricity demand and supply	2019 E3 Avoided Cost Calculator
Distribution losses	The incremental cost of electricity that enters the distribution network but is not delivered to customers	Borenstein and Bushnell (2022a), FERC Form 714, Ventyx
Generation capacity	For markets in need of new capacity, the marginal cost of attracting a new combustion turbine (or the benefits of deferring an investment). For markets with excess electricity supply, the capacity payment needed for the marginal generator to commit to being available during high-demand hours	2019 E3 Avoided Cost Calculator, ISONE, EIA, Borenstein and Bushnell (2022a), NOAA
Distribution capacity	The cost of adding additional capacity on distribution system (or the benefits of deferring an upgrade)	The Mendota Group LLC (2014), ResStock
RPS compliance	The net incremental cost of providing renewable generation to comply with a Renewable Portfolio Standard	2016 E3 Avoided Cost Calculator, Synapse, NREL, DSIRE, Gorman et al. (2019)
Carbon	The social cost of CO_2 emitted due to the incremental output of the marginal generator	Borenstein and Bushnell (2022a)
Other environmental damages	The costs of SO_2, NO_X, and $PM_{2.5}$ emitted due to the incremental output of the marginal generator	Borenstein and Bushnell (2022a)

3. Results

The study results are framed by six questions intended to identify key drivers and relationships between rate design features and investments in EE, DPV, and building electrification:

1. How do customer bills change under a flat rate as households invest in EE or DPV?
2. How do EE and DPV customer bill savings change as households move from flat rates to time-based rates?
3. What is the distribution of bill savings across EE packages and does that distribution widen or narrow under a particular rate design?
4. What happens to bills for customers that invest in building electrification under flat rates?
5. How do building electrification customer bill savings change as households move from flat rates to time-based rates?
6. Does moving from flat rates to time-based rates result in better alignment of EE and DPV bill savings with avoided costs and more economically efficient investment decisions?

We report results for electrification packages and customer bills separate from EE and DPV packages and customer bills, because electrification bill impacts are reported by change in energy bill inclusive of fossil-based fuel and electricity costs whereas EE and DPV bill savings are based on the change in electricity costs only. For each question, we explain the motivation, describe expectations for what might be observed in the results, and describe our observations. Implications of the results for decision-makers and utilities are discussed in Section 4.

3.1 How do customer bills change under a flat rate as households invest in EE or DPV?

The first step in estimating the impact of rate design changes on customer bills is to quantify bill savings under current default rates. This serves as the comparison point for energy and bill savings under time-based rates, which are presented in the following subsections. Under residential default rates that collect the vast majority of costs via volumetric energy consumption, the quantity of energy savings (kWh) drives bill savings. To assess this alignment between customer energy savings and bills, we compare energy savings to the volumetric portion of bill savings for upgrades when customers are on flat rates. Flat retail rates are designed with a similar volumetric energy charge in all hours. Therefore, we expect to observe equivalent proportional savings for energy and customer bills. We see that, in most cases, median energy savings and bill savings[18] are equivalent regardless of EE upgrade (see Figure 4). We observe small differences between median energy savings and bills savings for all Great Plains utility and some Midwest utility results, which are due to seasonal differences in rates and tiered pricing for flat rates. Broadly speaking, however, we find that bill savings are directly proportional to energy savings for flat rates.

[18] We remove fixed fees from this calculation in order to isolate the relationship between volumetric energy charges and volumetric energy consumption. We also report median bill and energy savings instead of mean because the median values are not skewed by extreme outliers of customer consumption profiles in the ResStock dataset.

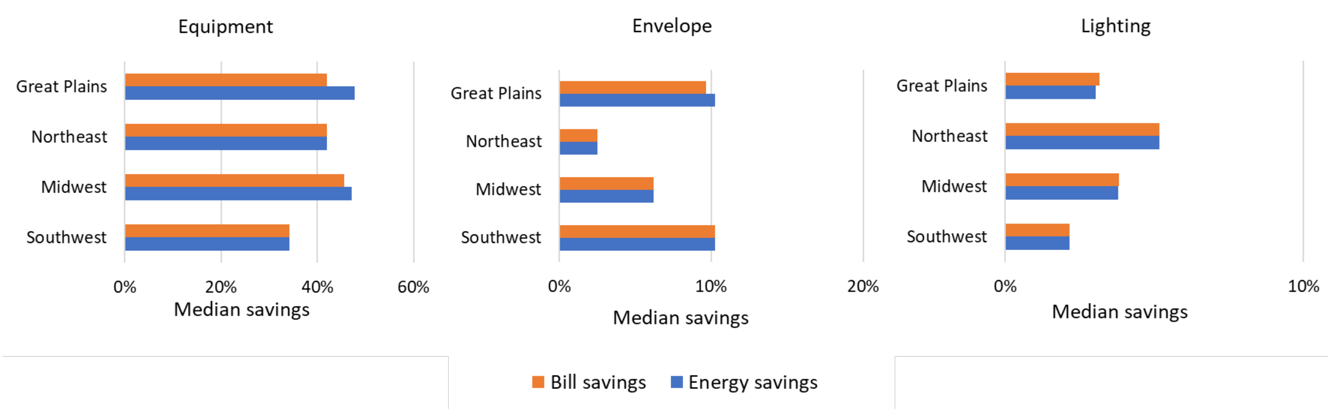

Figure 4. Comparison of EE package energy savings and volumetric energy bill savings with flat rates

Using the same approach, we compare the customer energy savings and bill impacts of DPV under flat rates for three different DPV system orientations. Customers typically adopt DPV technologies to reduce their electricity bill through lowering their net usage. However, the potential bill impact of rooftop solar can differ substantially from total DPV generation when net exports are not compensated since DPV often creates periods when generation is greater than consumption.[19] Across the four utilities, we again observe strong alignment between median energy and bill savings with small differences due to seasonal and tiered rates for the Great Plains and Midwest utilities (see Figure 5). Even with the value of exported solar excluded, we observe that customer bill savings are approximately 40% of bills in all cases. Figure 5 also shows the orientation of rooftop solar has very little effect on average energy and bill savings.[20]

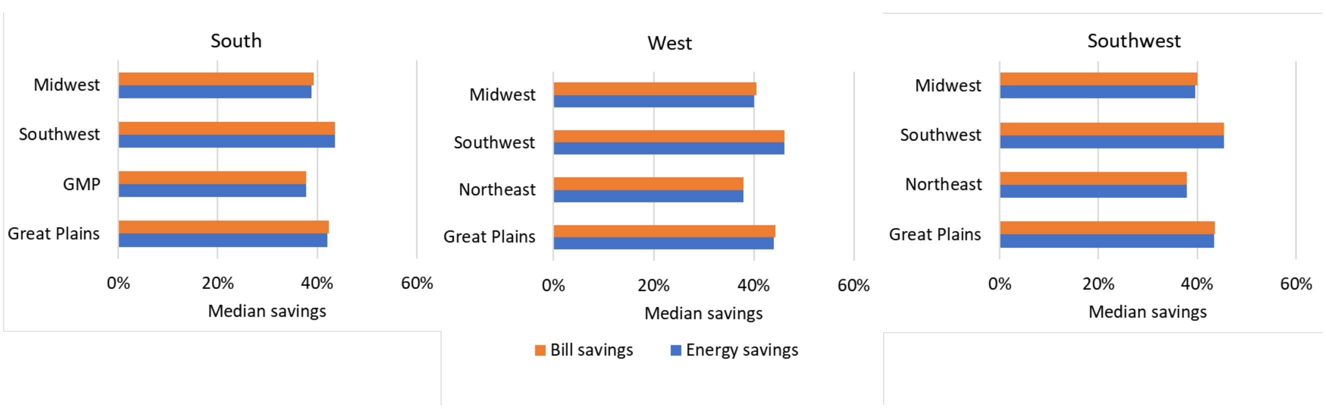

Figure 5. Comparison of DPV system orientation energy savings and volumetric energy bill savings with flat rates

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[19] As described previously, we assign no compensation to exported solar in order to focus on the impacts of self-consumption and control for the differences in net metering practices among the four utilities.

[20] We remove fixed fees from this calculation in order to isolate the relationship between volumetric energy charges and volumetric energy consumption. And, as noted previously, DPV is sized equal to building consumption and the assumption could mitigate some of the differences in DPV system orientation.

3.2 How do EE and DPV customer bill savings change as households move from flat rates to time-based rates?

A customer's bill savings under time-based rates depends on when the energy savings from EE and DPV occur. For example, TOU rates are designed with different multi-hour peak and off-peak price periods. While the peak period is generally designed to be higher than the flat rate, the off-peak period is generally lower than the flat rate. We, therefore, expect to see an increase in bill savings for upgrades that tend to emphasize peak period energy savings and a decrease in bill savings for upgrades that primarily reduce energy usage during the off-peak periods.

Across the EE packages, utility time-based, and event rates, we find that the median change in bill savings when moving from a flat rate to a time-based rate is less than 2 percentage points (pp) in all cases. Figure 6 shows the median change in bill savings from moving from a flat to a time-based rate as a percentage of a customers' total bill, with results broken down by upgrade package and rate schedule. Figure 7 shows the same results when we normalize for changes in fixed charges. While average bill savings impacts are positive for some simulated scenarios and negative for others, the magnitudes of these average changes are consistently less than 2% of a customers' total bill and most often less than 1% of a customer's bill. Overall, we find that the potential for significantly increasing or decreasing electricity bill savings from EE investments when moving from a flat rate to a time-based rate is relatively small.[21]

While time-based rates reduce median bill savings in almost three fourths of the simulated scenarios under the utility tariffs, comparing Figure 6 and Figure 7 shows that this tendency towards a reduction in bill savings can partly be explained by increases in fixed charges. When we normalize for fixed charge changes, we find that median bill savings decrease significantly in only a little over half of the scenarios, with bill savings from envelope packages increasing under most rates. Controlling for fixed charge changes also tends to shrink the bill saving impacts. For example, the vast majority of the bill savings reduction from the Midwest utility's real-time price rate can be attributed to an increase in the fixed charge.

We observe the greatest change in bill savings for equipment measures, event-based rates, and the Southwest utility TOU+demand rate. The especially large percentage point bill saving changes for equipment upgrades can be fully explained by the especially large kWh energy reductions from these packages, as shown in Figure 4. These bill saving change estimates reflect the change in bill savings as a share of the customer's total bill before the upgrade. Since energy and bill savings are highly correlated, larger energy reductions tend to lead to larger percentage point changes in bill savings.[22] The event and demand charge rates collect a large share of revenue from a small number of hours. As a result, bill

[21] Bootstrapped standard errors are omitted for simplicity. See Appendix E for key result charts with 95% confidence intervals.

[22] See Figure E-14 for a box-and-whiskers plot of the package- and rate- specific changes in bill savings as a percentage of bill savings under a flat rate. This metric controls for the magnitude of the energy savings.

savings under these rates are especially sensitive to the timing of electricity savings, creating the potential for especially large increases and reductions in bill savings.

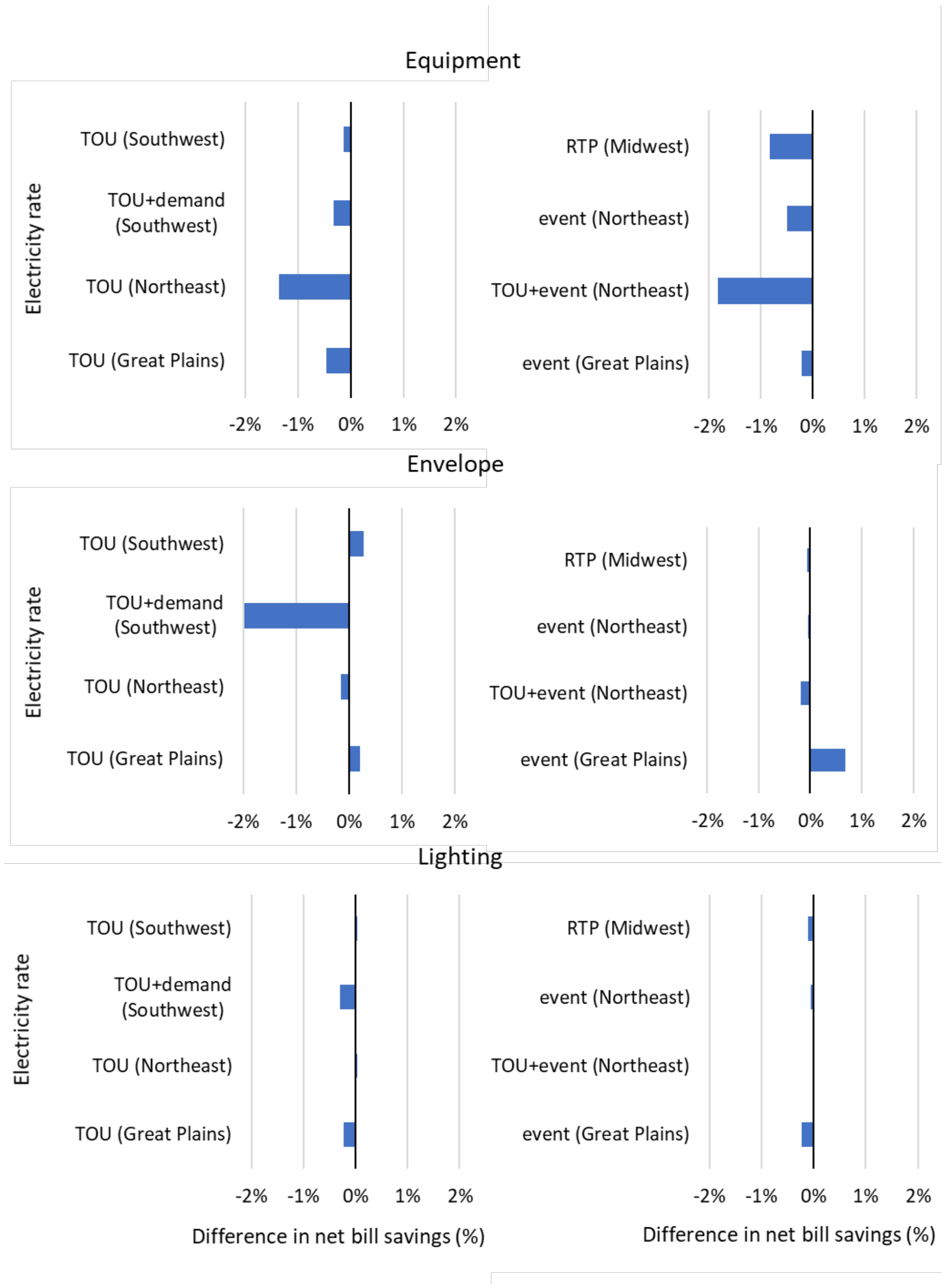

Figure 6. Difference in EE bill savings for time-based rates compared to flat rates

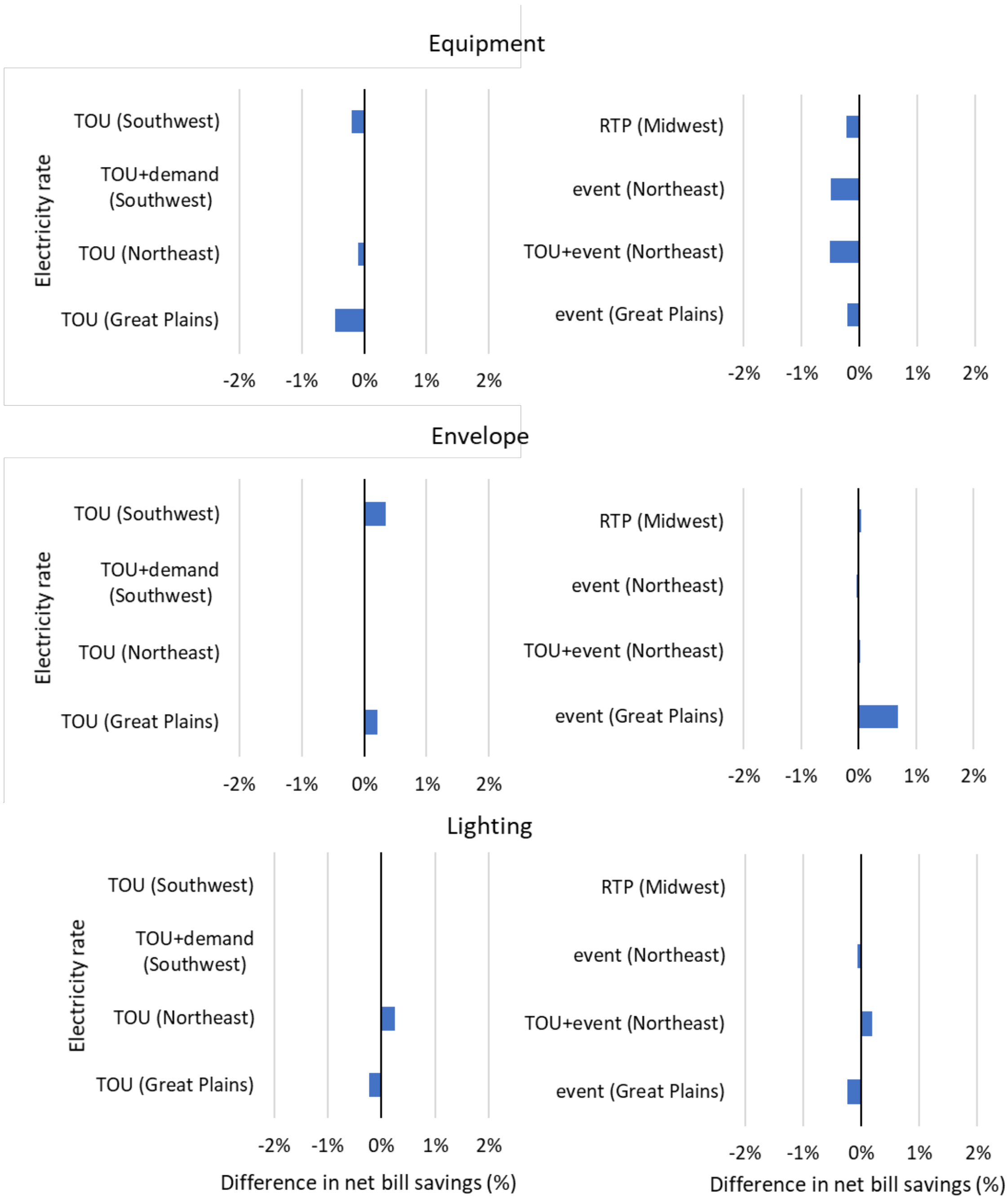

Figure 7. Difference in normalized EE bill savings for time-based rates compared to flat rates to account for differences in fixed charges

Whether an EE upgrade tends to produce savings off-peak, on-peak, or during peak event periods can explain why most changes in bill savings with time-based rates are small.
Figure 8 shows the total median bill savings and their allocation among flat, off-peak, peak (both volumetric and demand), and event rates, and Figure 9 shows the proportion of energy savings among these rate periods. In most cases, the majority of bill savings occur in off-peak periods, and the share of off-peak savings is statistically significantly higher than the share of electricity usage in off-peak periods

without any upgrades. However, this difference is small. On average, the share of electricity consumed during off-peak periods drops from 58.6% to 58.4% with energy efficiency upgrades. This small change in the share of usage off-peak can explain why bill savings impacts from time-based rates are small.

Figure 8. Median EE bill savings by rate type

The timing of energy efficiency savings can also explain much of the variation shown in Figure 6 and Figure 7. For the Northeast utility's time-of-use rates, we observe that the share of peak energy savings is highest for lighting upgrades followed by envelope upgrades because the affected end-uses drive utility peak demand. For the Southwest and Great Plains utilities, we find envelope upgrades have a higher proportion of energy savings in the peak period than lighting or equipment upgrades. The differing shares of energy savings in peak periods across utilities for the same EE upgrade is primarily due to slightly different peak period definitions (see Figure 2). For event-only rates, the proportion of energy savings that occurs during the event periods is noticeably higher for envelope and lighting upgrades (e.g., 31% to 37% peak and event savings for the Northeast utility TOU+event rate) than for equipment upgrades (e.g., 22% peak and event savings for the Northeast utility TOU+event rate). Equipment upgrades have the highest total bill savings of all the upgrade packages in our study but the lowest peak period or event alignment, because the equipment upgrade package measures affect a large number of end-uses, many of which do not drive utility peak demand (e.g., dishwashing, refrigeration).

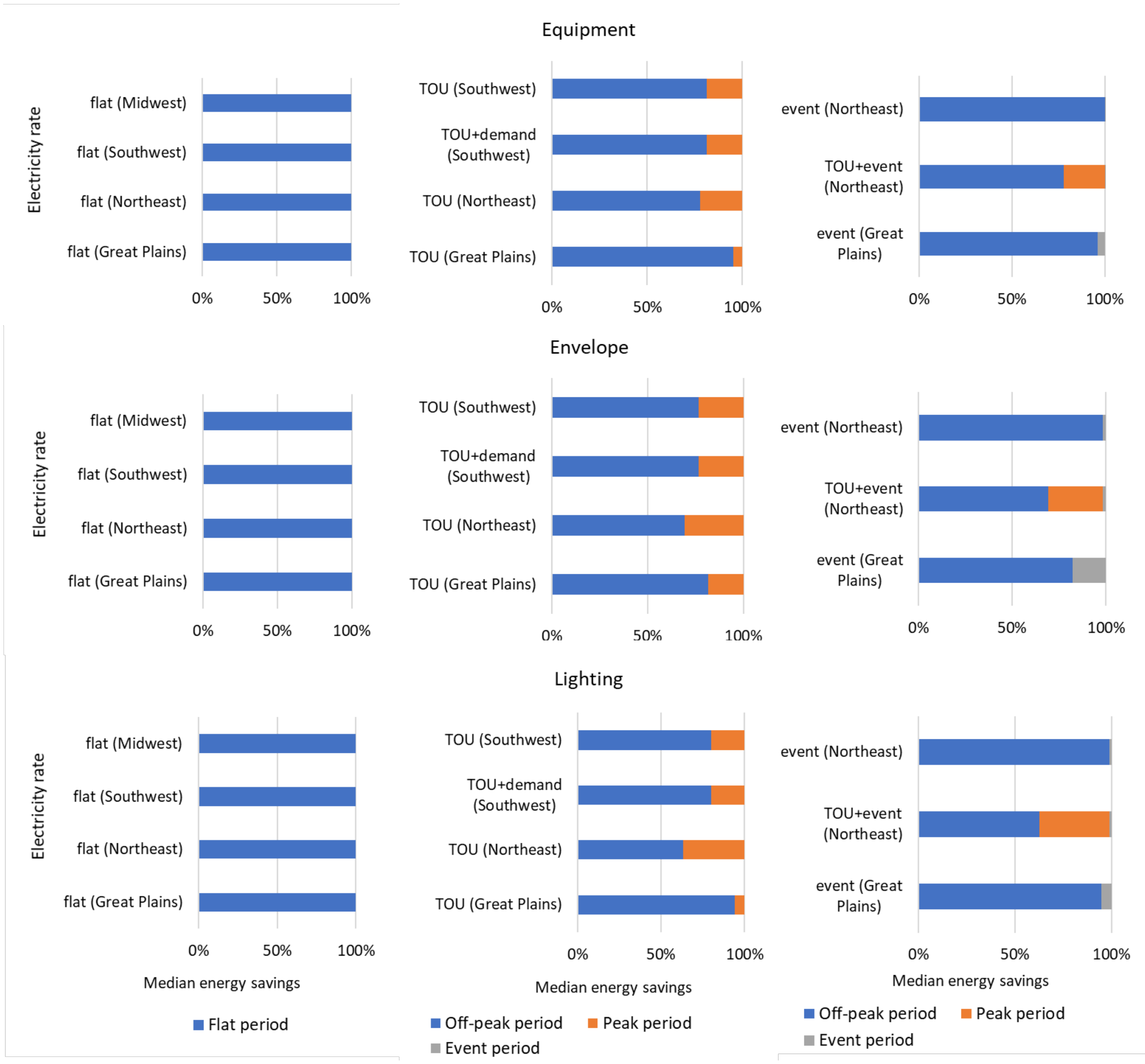

Figure 9. Median EE energy savings allocated by rate period

We also examine how time-based rates affect potential energy and bill savings for DPV. We calculate the difference in bill savings by first calculating the percent change in bill savings before and after DPV is added for each rate. Then, we take the difference between the median customer's bill savings for each time-based rate and its respective flat rate as the net total utility bill savings. We generally observe small changes in total DPV customer bill savings when moving from flat to time-based rates (i.e., the majority of bill changes are less than 2 percentage points) (see Figure 10). The most significant changes in bill savings come from the Great Plain utility's TOU and event rates, which result in net increases in bill savings of 3 pp and 6 pp, respectively. In the opposite direction, the Southwest utility's TOU+demand rate shows an 8 pp net decrease in bill savings compared to bill savings under the same utility's flat rate. These rates exhibit particularly high variation over time, which increases the potential for especially large increases or decreases in savings. The Great Plains utility TOU and event rates exhibit especially high prices during summer afternoons, when DPV generation is high. The large reduction in bill savings under the demand charge rate is largely due to a smaller volumetric rate compared to the flat rate (as shown in Figure 11) and DPV being limited in reducing demand charges due to low generation in the evening when customer usage is high.

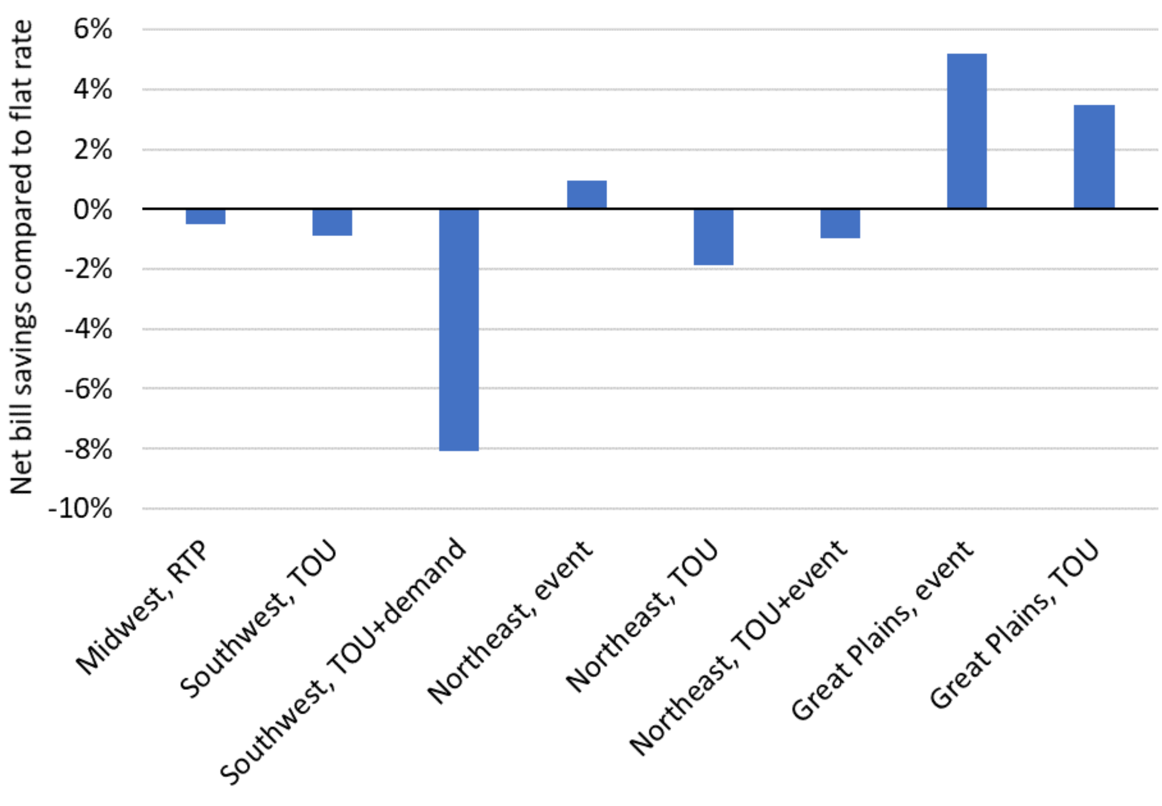

Figure 10. Difference in south-facing PV bill savings from time-based rates compared to flat rates

The change in PV customer bill savings from moving from flat to time-based rates is primarily explained by the difference in the average time-based rate level and average flat rate level.[23] Figure 11 shows the percentage change in the average volumetric rate level between time-based rates and the flat rate for each utility. Some of these average rate changes can be attributed to shifting revenue collection from variable to fixed charges or vice versa (see APPENDIX E for results with normalized fixed charges). Similar to the difference in DPV customer bill savings, the difference in average volumetric rates is highest for the Southwest utility TOU+demand and Great Plains utility event rates.[24]

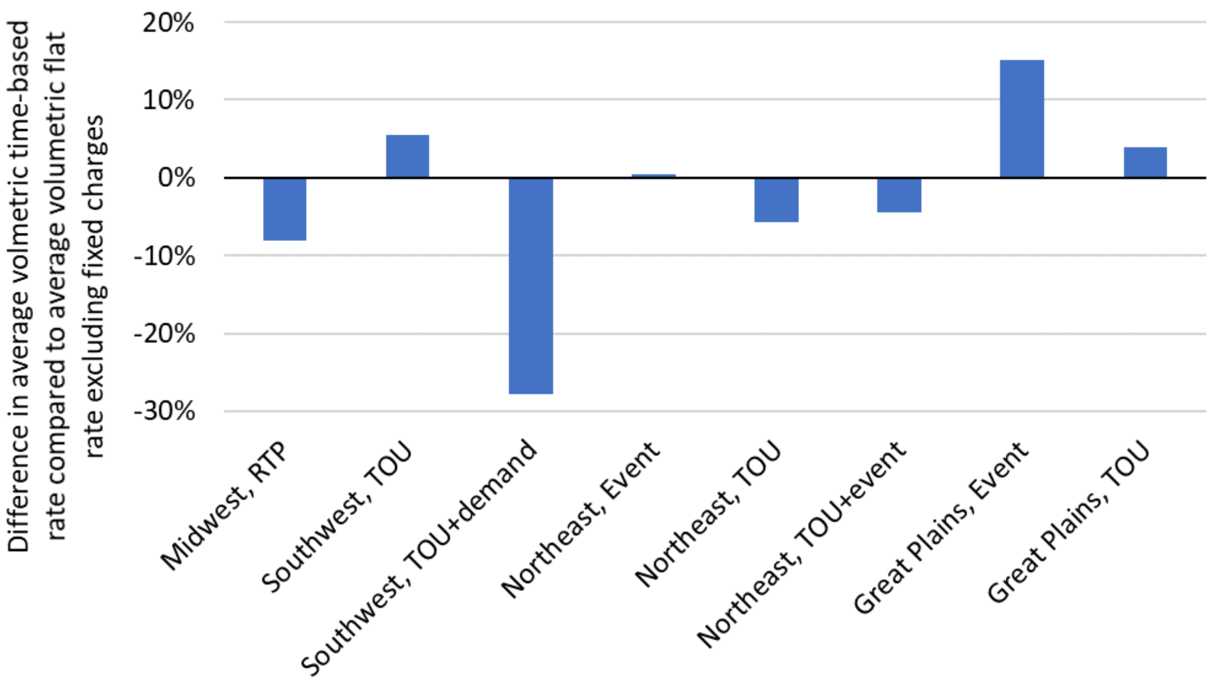

Figure 11. Difference between average volumetric time-based and volumetric flat rates (fixed charges are excluded)

[23] We calculate the average time-based electricity rate by first calculating the total cost of electricity for the aggregate load of all customers in each hour using the electricity rate in that hour. We then sum the hourly cost of electricity for all hours and divide by the total annual aggregate residential load from ResStock in order to calculate an average time-based electricity rate, represented in dollars per kilowatt-hour ($/kWh).

[24] Some of the change in bill savings may also be attributed to the timing of electricity consumption relative to the usage shape used for setting rates. For example, a customer that uses a small share of their electricity on peak relative to the rate-setting on-peak share will experience a lower average electricity rate and a larger share of non-exported DPV generation at the low off-peak price, all else being equal. The utility's hourly shapes for rate-setting are not publicly available and we are unable to quantify the magnitude of this difference.

3.3 What is the distribution of bill savings across EE packages and does that distribution widen or narrow under a particular rate design?

Utilities and regulators commonly consider average customer bill impacts when assessing the impact of rate design changes. However, the "class average customer" consumption profile and electricity bill may be quite different than many actual customers' consumption profiles due to significant heterogeneity in building characteristics, end-use technologies, and energy consumption behavior, among other drivers. We explore the distribution of EE bill savings in order to understand the potential impact of upgrades and time-based rates across all customers in our dataset.[25] Such an analysis can inform discussions about the equity implications of rate design changes, including whether certain customers are likely to see large bill increases and how costs and benefits are shared across the customer class.

Given the heterogeneity of building characteristics in our dataset, we expect fairly large variation in customer bills. We assess the distribution of EE bill savings using the calculation method discussed previously. We report bill savings as box-and-whisker plots where the farthest lines represent the lowest and highest customer bill savings values, and the box lines represent the first quartile, median, and third quartile values. Consistent with our expectations, we observe wide variation in customer bill savings across utilities and EE packages under flat rates (see Figure 12). In some cases, the 75th percentile of EE bill savings is more than four times the median bill savings (e.g. Midwest utility EE lighting package 75th percentile bill savings of 15.2% are almost 4.5 times higher than the median bill savings of 3.4%). The distribution of EE bill savings is also generally greater for envelope and lighting packages than equipment packages.

[25] In this section, we do not explore the distribution of DPV customer bills. In practice, customers will size DPV systems differently and potentially change end-use consumption in response to having DPV. We are unable to model these and other differences in the DPV system designs, aside from orientation.

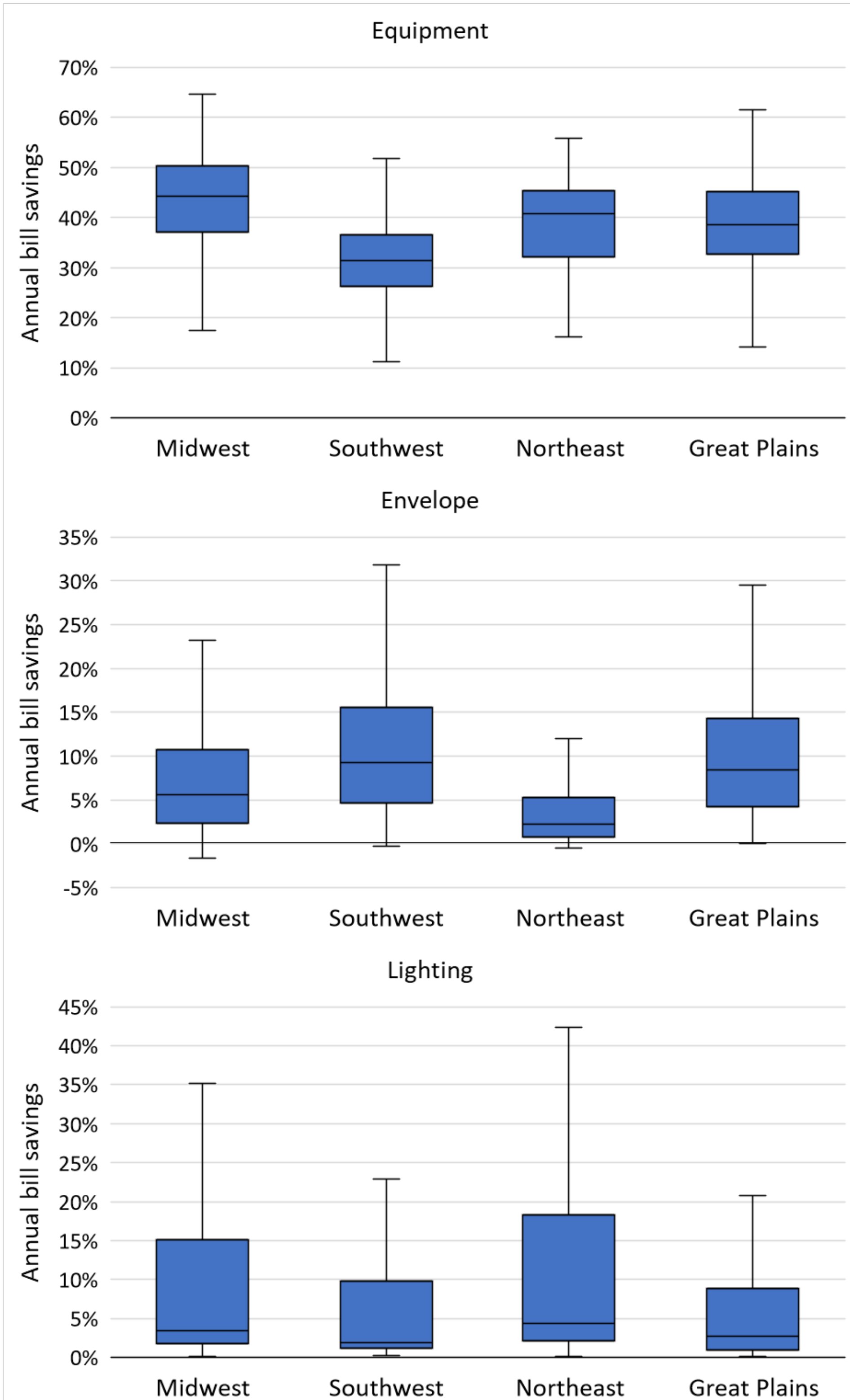

Figure 12. Distribution of EE bill savings by package under flat rates

Similar to the small impact of time-based rates on *average* EE bill savings, we observe that the impact of time-based rates on the *variance* of EE bill savings is also small. While time-based rates widen EE bill savings distributions more often than narrow them, only one sixth of the utility-rate-package combinations result in an increase in the variance of bill savings greater than 10%, and only the rate with a demand charge increases variance by more than 16%.[26] Figure 13 shows the distribution of the percentage change in bill savings from EE for each rate and upgrade packages for the Northeast utility. The figure confirms that the changes in the full distributions of bill savings across rates are visibly small. The results for the other utilities are similar (see APPENDIX E). Figure 14 shows the distribution of these changes in bill savings for each time-based rate and EE package. The vast majority of customers experience a change in bill savings smaller than 2% of their total bill, and almost no customers experience a reduction in bill savings greater than 6% of their bill. These results confirm the relatively low risk that time-based rates will significantly undermine EE deployment efforts.

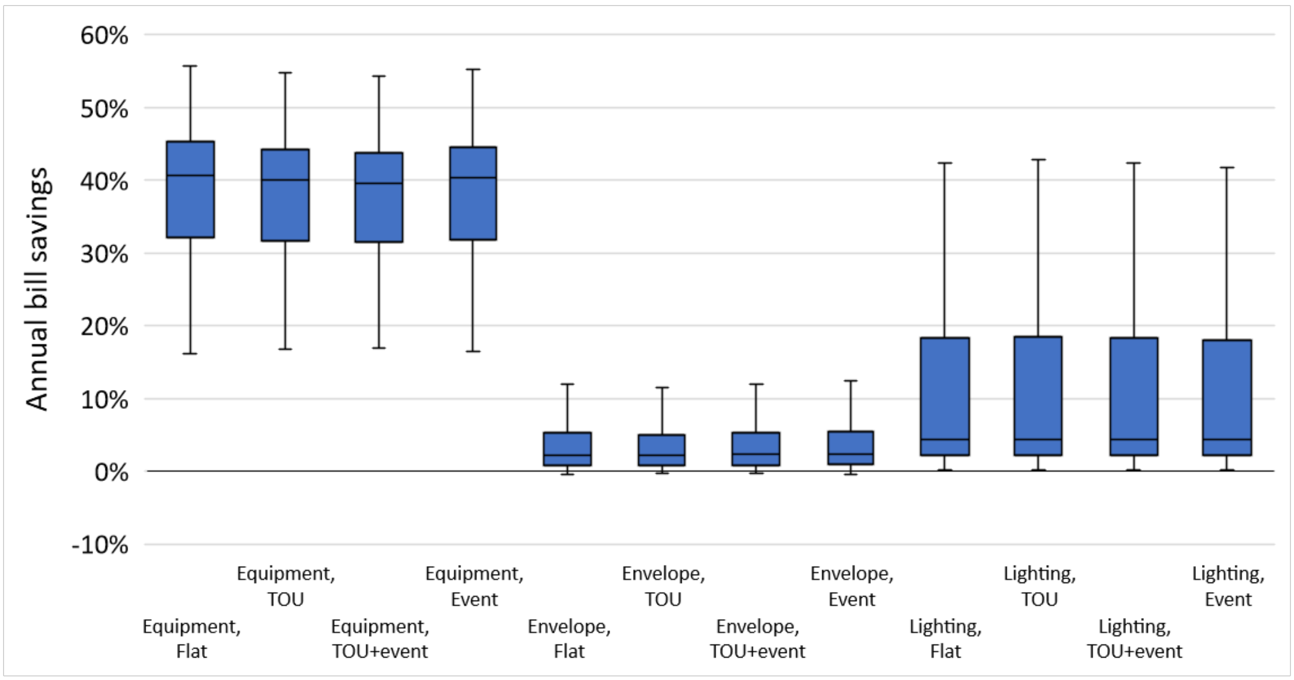

Figure 13. Distribution of EE bill savings for the Northeast utility across packages and rate designs

[26] These results hold when we normalize for fixed charge changes.

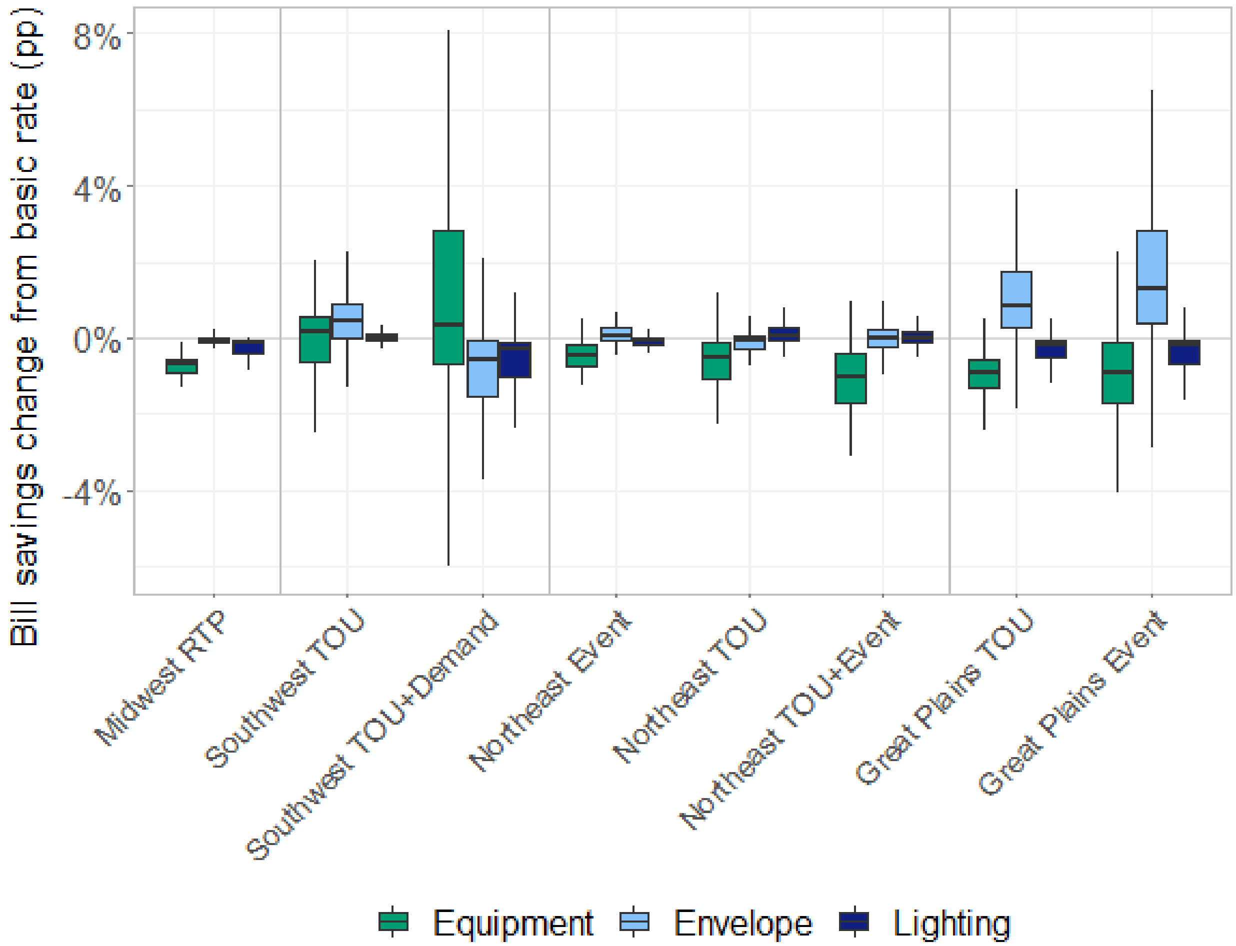

Figure 14. Distribution of percentage point changes in EE bill savings by package and rate design (outliers are excluded)

3.4 What happens to bills for customers that invest in building electrification under flat rates?

Unlike EE upgrades and DPV that reduce electricity consumption, building electrification may result in a net increase in customer electricity consumption with a corresponding, but not necessarily equivalent, decrease in fossil fuel consumption. We examine energy and bill impacts for a comprehensive package of building technologies that electrify equipment powered by other fuel sources in the baseline (i.e., natural gas, propane, or fuel oil). Importantly, the building electrification package includes efficient electric equipment upgrades for electric and non-electric building technologies in the baseline (e.g., an efficient electric clothes dryer that replaces either a less-efficient or non-electric clothes dryer).[27] The building electrification package also includes efficiency measures that would be commonly included in a

[27] We refer to "electric" and "non-electric" end uses throughout to broadly categorize the different upgrade strategies in the electrification package. If the baseline end use is electric, the upgraded end use is still electric but more efficient, which reduces electricity consumption. If the baseline end use is non-electric, the upgraded end use is electrified, which eliminates non-electric consumption for that end use but *increases* electricity consumption.

building electrification retrofit project (e.g., ducting replacement or retrofit for reduced leakage and higher insulation levels). Unlike prior studies that explore a roughly equivalent change in building technology fuel source (Sergici et al., 2023, Hermine et al., 2022), our building electrification package includes the efficiency improvements that are likely to occur in comprehensive building electrification retrofits.

Non-electric fuels in the baseline building stock reflect ResStock modeled fossil-based end-uses based on survey data for location-specific appliance saturation rates. The non-electric fuels include natural gas and propane for all utilities and fuel oil for the Northeast utility only. Figure 15 shows the share of non-electric fuels in the baseline building stock (left bars) compared to the building electrification upgrade (right bars) normalized on a kWh/month basis. Prior to the electrification upgrade, monthly average *energy* consumption is higher across all utilities, whereas monthly average *electricity* consumption is either higher (for the Northeast and Midwest utilities) or lower (for the Southwest and Great Plains utilities) depending on the cumulative effects of the relative efficiency increase from the electrified end-use technology, as well as additional efficiency gains from other EE measures included in the building electrification upgrade package.

The volumetric price of non-electric fuels on a $/kWh basis is lower than the average price of electricity in nearly all cases. The difference between average electricity and natural gas prices is especially pronounced (e.g., the natural gas price is as much as ten times lower in the Midwest utility) (see Table 3). Like energy and bill savings for other upgrades, we calculate the difference in energy consumption and the total bill for each building using the building electrification package and baseline profiles. However, for building electrification, we include the consumption and cost of all fuels in order to calculate total *energy* and *energy bill* savings.

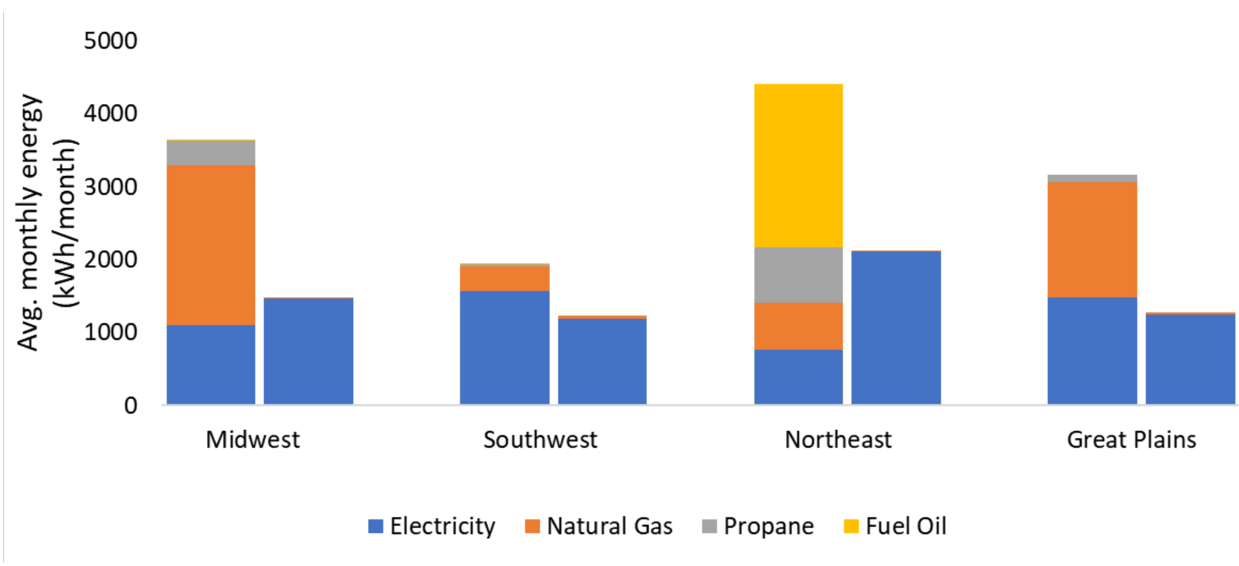

Figure 15. Average monthly energy consumption for baseline (left) and building electrification upgrade profiles (right)

Table 3. Comparison of utility average volumetric energy prices by fuel type

Price ($/kWh)	Midwest	Southwest	Northeast	Great Plains
Electricity (flat rates)	0.19	0.13	0.19	0.07
Average natural gas	0.02	0.05	0.05	0.02
Average propane	0.06	0.07	0.11	0.07
Average fuel oil	N/A	N/A	0.06	N/A

Across the distribution of customers[28], we find a consistent reduction in total energy consumption when customers install a comprehensive portfolio of efficient electric building technologies (see top panel of Figure 16). Median customer energy savings range from 39% to 61% and difference across utilities are driven by pre-upgrade consumption levels and mix of fossil fuel technologies.

For electrification strategies under flat rates, we observe bill savings for all customers in the Southwest and Great Plains utilities while the Midwest and Northeast utility results show roughly half of customers experience bill decreases and half experience bill increases (see bottom panel of Figure 16). Although the efficient electrification measures produce total energy savings across the distribution of customers (see top panel of Figure 16), the much higher price of electricity relative to fossil fuel prices results in energy bill increases for some customers (see Table 3 and Figure 16). This is most evident for Midwest utility customers, who see a 61% decrease in median energy consumption but a 3% increase in median energy bills due to the much higher cost of electricity compared to natural gas. The distribution of customer energy bill savings is large and varies significantly across utilities, and suggests, in some cases, that a large proportion of customers may face increased electricity bills when adopting building electrification measures. For example, 25% of Northeast utility and Midwest utility customers experience bill *increases* of at least 27% and 38%, respectively.

[28] We define the distribution of customers as between the 10th and 90th percentiles based on total annual electricity consumption in each scenario in order to remove the effects of outliers.

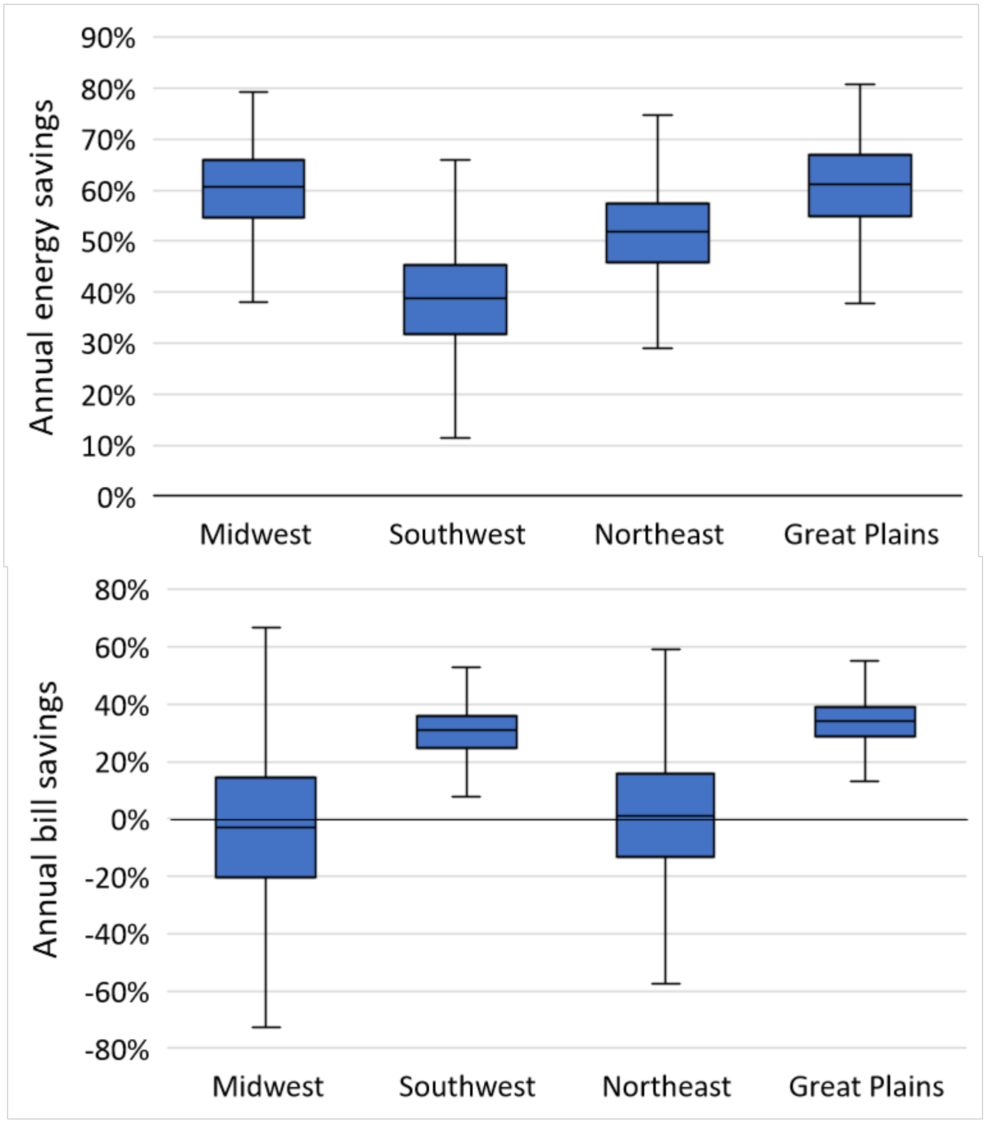

Figure 16. Distribution of energy savings (top panel) and energy bill savings (bottom panel) for building electrification upgrades

We further explore the energy bill savings by isolating instances where customers electrify heating, cooling, and water heating end-uses. This analysis allows us to isolate the impact of electrification itself from accompanying energy efficiency measures. Space and water heating are the most commonly electrified end-uses, and the most efficient electric space heating technology (i.e., heat pump) includes air conditioning. Figure 17 shows the distributions of customer bill savings for the portion of the energy bill associated with space heating (top panel), water heating (middle panel), and cooling (bottom panel) end-uses.[29] Accounting for energy bill savings on an end-use basis reveals significant differences across

[29] Space heating, water heating, and cooling hourly load shapes for each building were taken directly from the end-use disaggregated ResStock data. The hourly load shapes include interactive effects between end-uses, albeit small effects that do not materially affect the results (e.g., a heat pump water heater draws heat from the building space, which decreases cooling load and increases heating load)

utilities due to differences in electricity price, climate, and underlying penetration of fossil-based technologies.

Importantly, the results suggest that the electrification measures can, in many cases, improve the efficiency of end-use energy consumption. In fact, for both space heating and water heating, all buildings for all utilities save energy[30] with the modeled electrification package compared to the baseline.[31] Replacing fossil-based space and/or water heating technologies with heat pumps is much more energy efficient (e.g., heat pumps can transfer 300-400% of energy they consume compared to 90-95% for a natural gas furnace). Similarly, replacing electric resistance space and water heating with heat pumps is more efficient.

Notwithstanding the importance of these efficiency gains from older equipment, there are still instances in which space and water heating electrification results in higher customer electricity bills due to the higher cost of electricity. For example, Figure 17 shows that most Midwest utility and Northeast utility customers experience increases in their space heating costs. The results reinforce the importance of the differences between electricity prices and non-electric fuel prices in driving customer energy bill outcomes.

[30] We refer here to energy consumed at the residential building (i.e., site energy).

[31] Some residential buildings see increases in cooling consumption as a result of the electrification package because heat pumps are installed where the residential building previously had no cooling load.

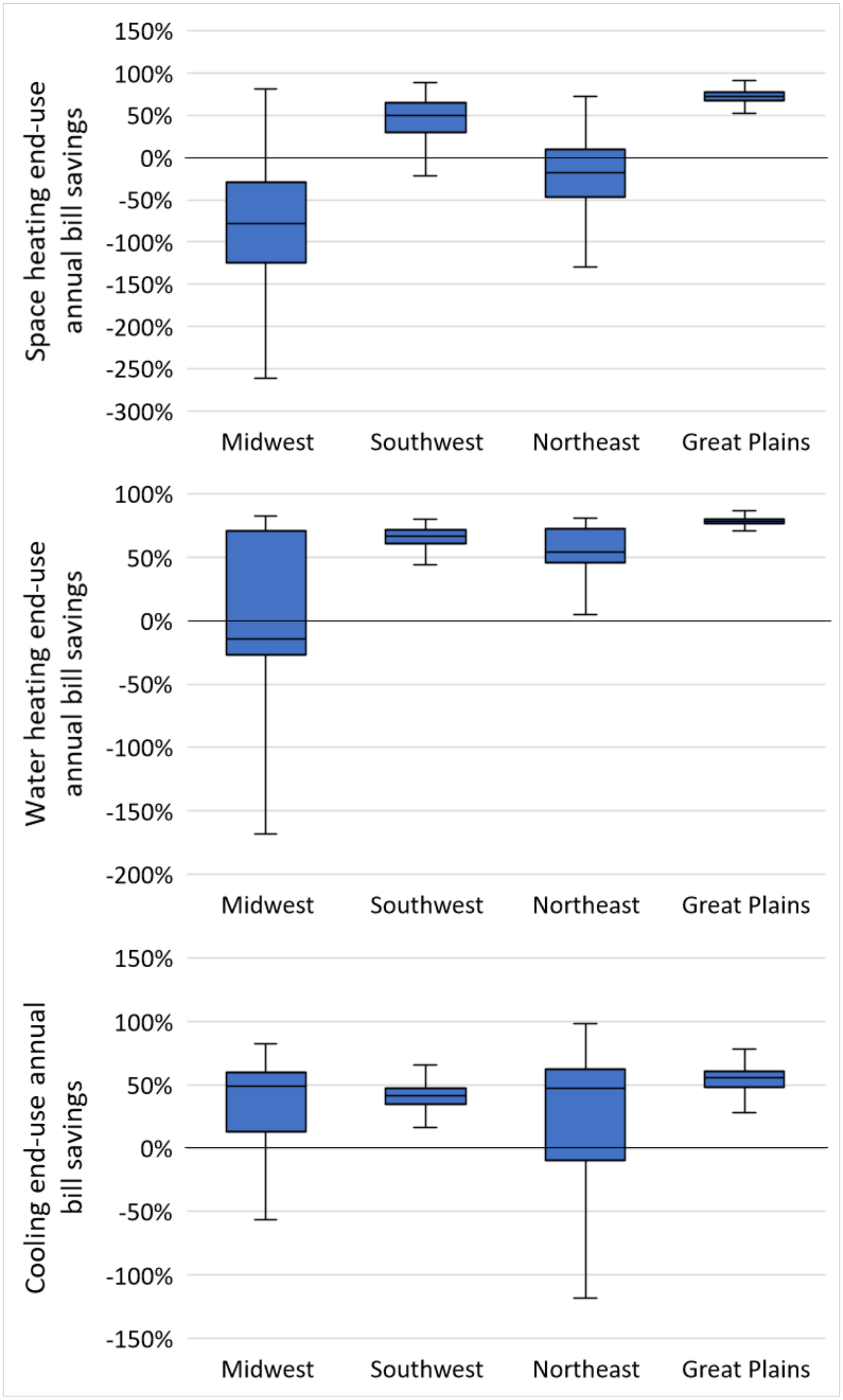

Figure 17. Distribution of building electrification energy bill savings for flat rates separated by space heating (top), water heating (middle), and cooling (bottom) end uses

3.5 How do building electrification customer bill savings change as households move from flat rates to time-based rates?

We quantify the difference in energy bill savings based on the median customer's energy bill savings under the time-based rate and flat rate for each utility and rate combination in order to capture the impact of moving to time-based rates with electrification. Under the current tariffs, we observe a net increase in energy bill savings for all time-based rates (see Figure 18). This result persists for most rates even if we normalize for fixed charge changes (see Figure 19). The impact of the rate design change is particularly large for the Northeast utility TOU+event rate, where the increase in average energy bill savings is close to 10 percentage points (7 percentage points when normalized for differences in the fixed charge changes).

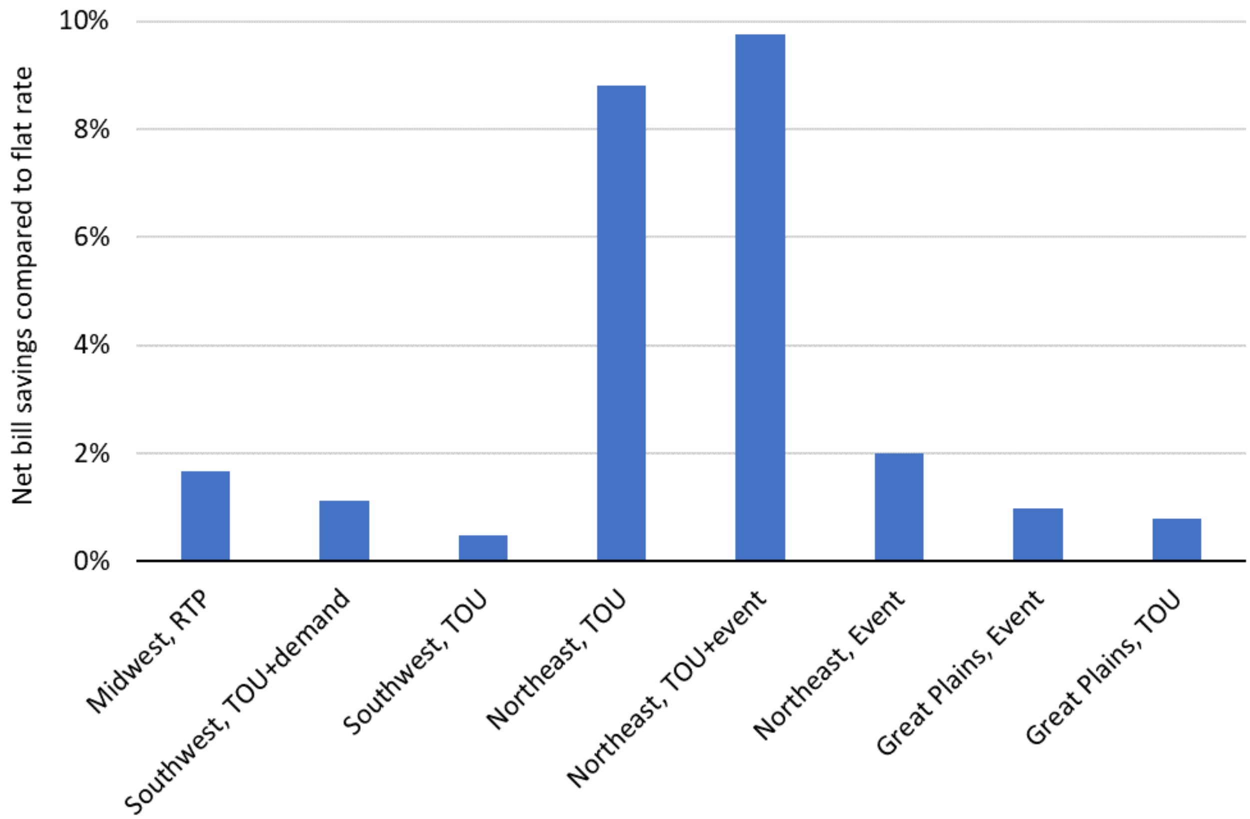

Figure 18. Difference in building electrification net energy bill savings for time-based rates compared to flat rates

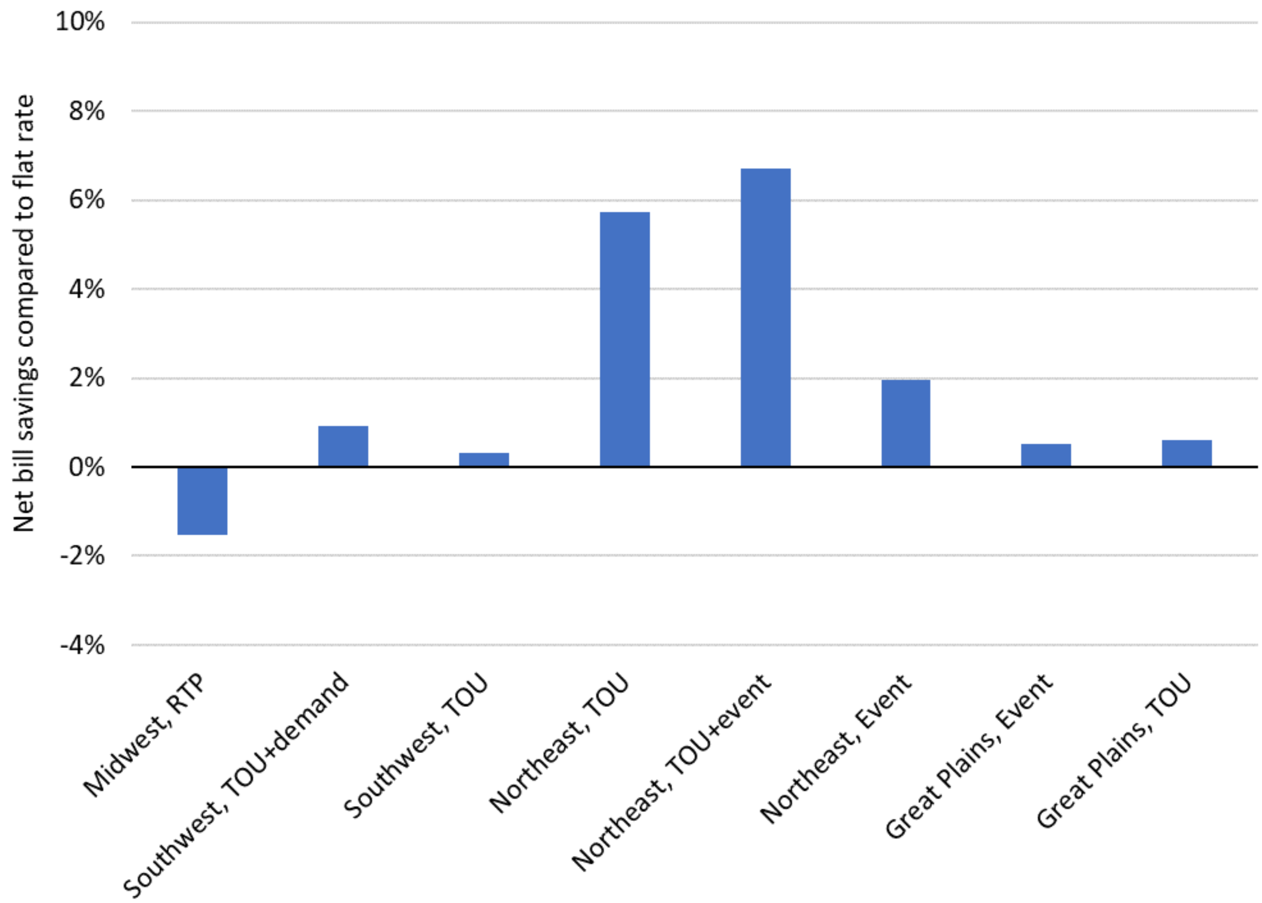

Figure 19. Difference in normalized building electrification net energy bill savings for time-based rates compared to flat rates

We next examine the distribution of energy bill savings across time-based electricity rates. Figure 20 shows box-and-whicker plots of the distribution of customer energy bill savings under flat and time-based rates, excluding outliers. The results show little difference in the spread (e.g., variance) of the distributions of energy bill savings across rate designs for the same utility. This suggests that time-based rates we selected have minimal impact on the variation in potential energy bill savings across customers compared to flat rates, similar to the EE results.

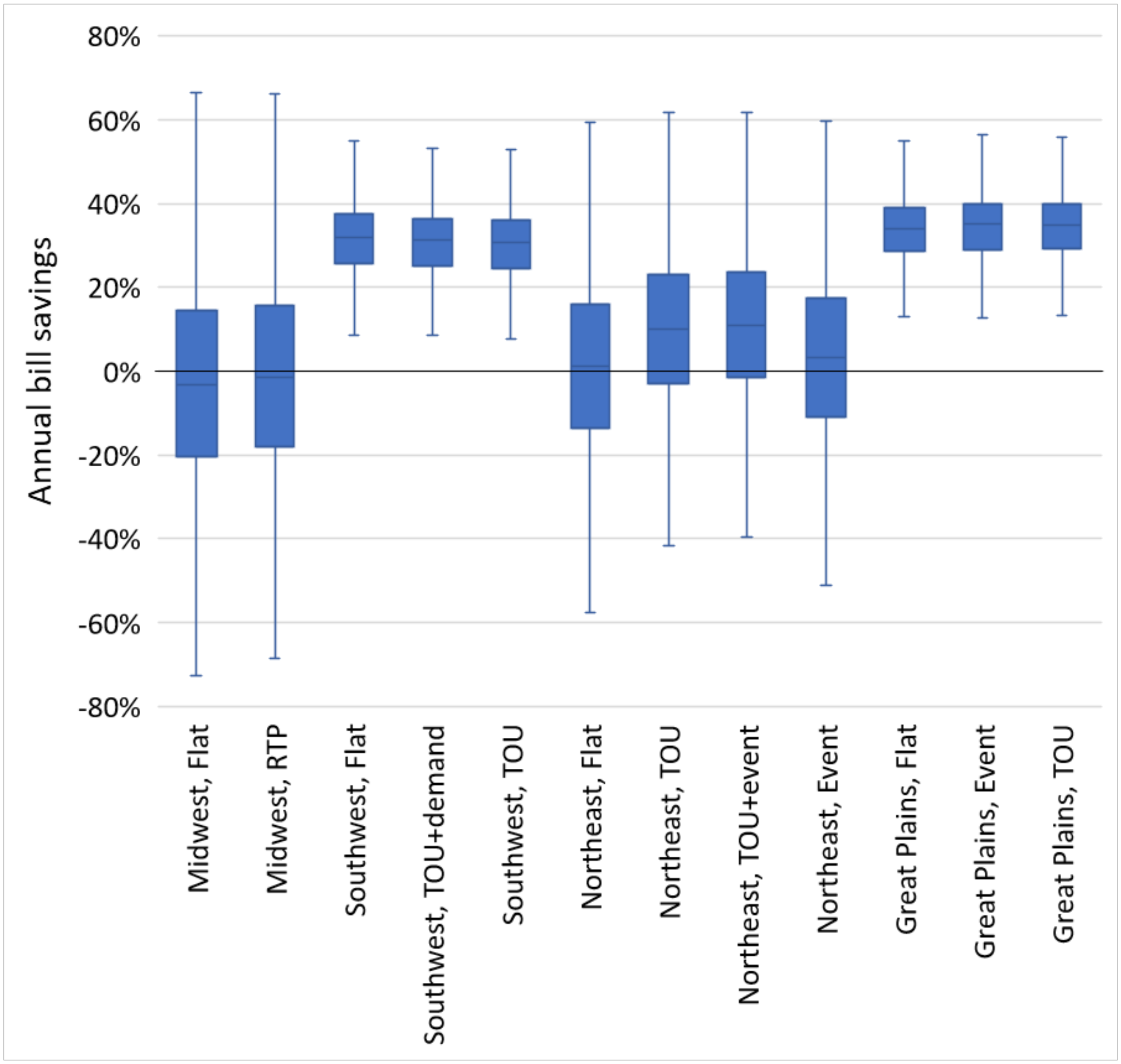

Figure 20. Distribution of building electrification energy bill savings across rate designs

3.6 Does moving from flat rates to time-based rates result in better alignment of EE and DPV bill savings with avoided costs and more economically efficient investment decisions?

Some utility regulators and utilities are interested in designing rates to achieve long-run power sector decarbonization objectives and time-based rates are intended to provide customers with more economically efficient signals of the *relative* costs of consuming electricity during different hours. We assess the alignment between customer bill savings and marginal societal costs when investing in EE and DPV to assess whether customers are being over- or under-incentivized for these investments. [32] We measure alignment using the ratio of bill savings to avoided societal costs ("incentive ratio"). An incentive ratio above one suggests that the bill savings from an investment are greater than the societal

[32] We exclude electrification package results from this analysis because our marginal societal costs exclude natural gas and other fossil-fuel based system costs.

benefits, and an incentive ratio below one suggests that the bill savings are less than the societal benefits. Importantly, an incentive ratio either greater than or less than one suggests an economically inefficient investment from the societal perspective.[33] If bill savings from EE or DPV are smaller than the societal benefits these investments create, this could lead to underinvestment in these technologies, greater emissions, and higher power sector costs. If bill savings are too high relative to societal costs, this could lead to overinvestment in these technologies, higher bills for other ratepayers, and lower investment in more beneficial technologies and products.

Figure 21 through Figure 24 present median incentive ratios for each retail rate, EE package, and DPV system orientation combination for the four regions. We present results with and without normalizing for changes in fixed charges. The rates are ordered from left to right by a measure of how much the rates vary with time.[34]

These figures show that time-based rates may not always improve the economic efficiency of investment decisions. As the time variation of rates increases, some incentive ratios move closer to one, and others move farther away. While the magnitudes of these incentive ratio changes are often smaller when we normalize for changes in fixed charges and isolate the time-varying nature of the $/kWh charges, we still see some instances where time-based rates improve alignment of an investment's bill savings and avoided costs and other instances where they exacerbate this misalignment.

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[33] Other perspectives could be considered depending on the marginal costs being considered (e.g., the utility system perspective would only include marginal costs consistent with a utility's revenue requirement).

[34] Specifically, the rates are ordered by the sum of the variance of $/kWh charges over hours of the year and the variance of $/kW coincident demand charges over hours of the year.

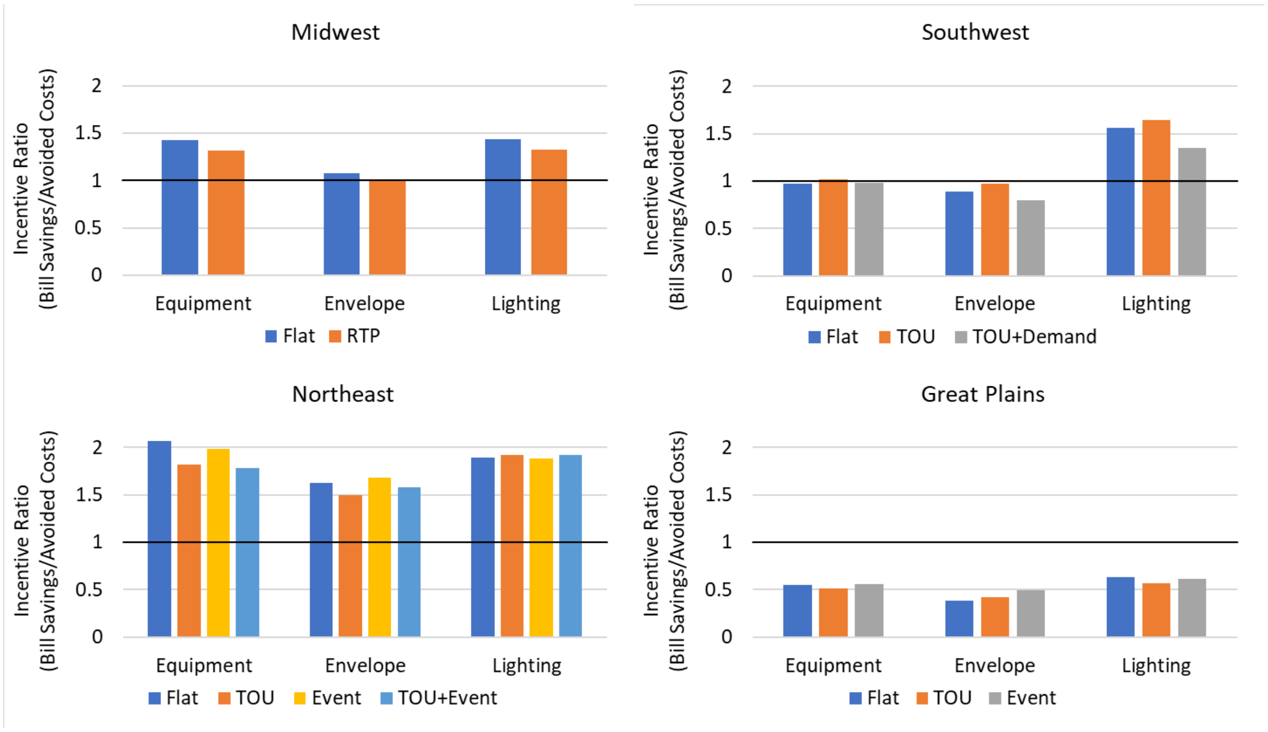

Figure 21. Median incentive ratios by utility, rate, and EE package

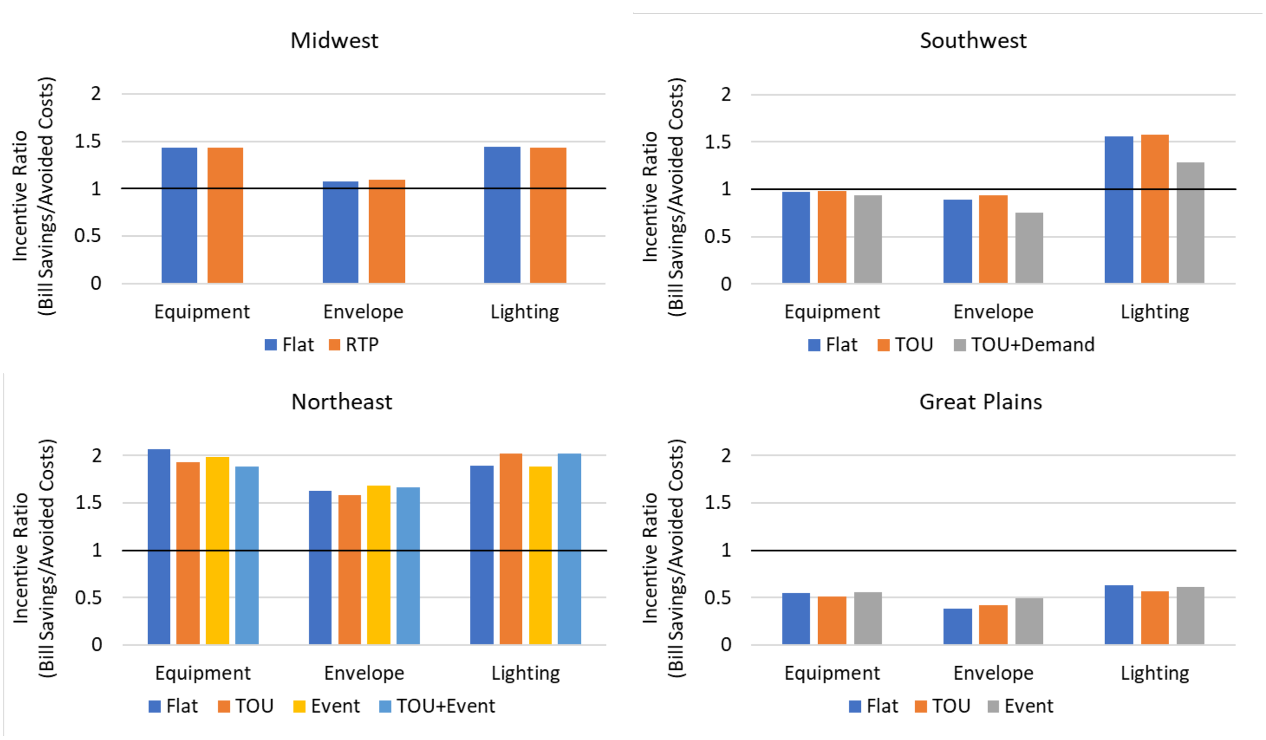

Figure 22. Normalized median incentive ratios by utility, rate, and EE package

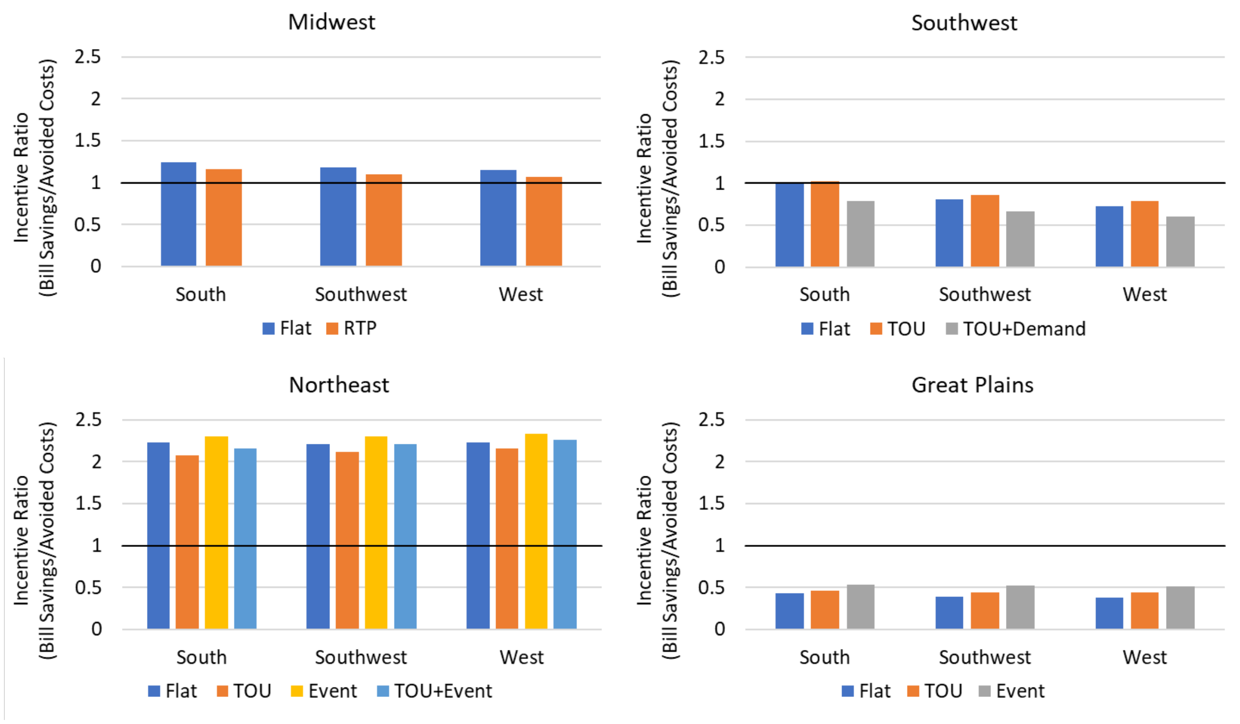

Figure 23. Median incentive ratio by utility, rate, and distributed solar PV orientation

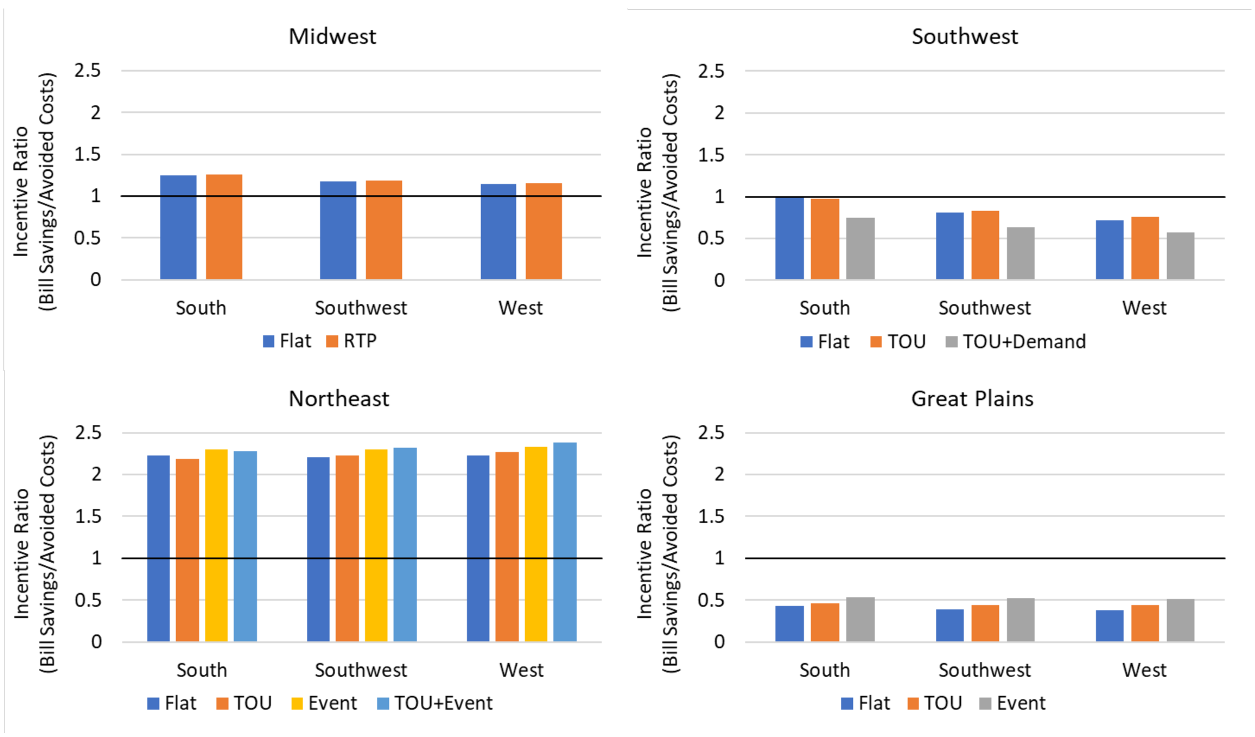

Figure 24. Normalized median incentive ratio by utility, rate, and distributed solar PV orientation

The differences in incentive ratios are most pronounced *across*, rather than *within*, utilities. This suggests that average rate level has a larger impact than rate design on whether EE and DPV bill savings are higher or lower than the societal benefits. Figure 25 shows average retail price less social marginal costs under the basic rate and total estimated residential usage for each utility. For the two utilities with the highest average rates, the Midwest and Northeast utilities, all rate structures offer bill savings *above* societal avoided costs (i.e., incentive ratios above one), which could lead to over-investment, across all rate designs, technologies, and orientations. For the utility with the lowest average rate, Great Plains, all rate structures offer bill savings *below* societal avoided costs (i.e., incentive ratios below one), which could lead to under-investment across all rate designs, technologies, and orientations. APPENDIX D reports the estimation approach and the results of a regression analysis that confirms the average $/kWh price under the basic rate is a stronger predictor than the time variation in rates of incentive ratios and whether EE and DPV are over- or under-compensated.

All else equal, investments with savings that are relatively more coincident with high system costs will have relatively lower incentive ratios under basic rates. For example, Figure 21 shows that incentive ratios are significantly lower for envelope upgrades than for all other modeled investments. This result is due to avoided social costs of envelope upgrades being particularly large per kWh avoided. Envelope upgrades save energy when system-wide demand for electricity (e.g., for heating or cooling) is high.[35] In the other direction, the Southwest utility incentive ratios are substantially above one for lighting despite average rates that are roughly equal to social marginal costs. Southwest utility social marginal costs are highest during late afternoons and early evenings in the summer when lighting use is low.

Figure 25. Difference in average retail price compared to social marginal costs under flat rates

35 Changes in fixed charges that accompany changes in the time-varying nature of the energy and demand charges may impact incentive ratios. Figure E-16 and Figure E-18 show the estimated incentive ratios if all rate designs had the fixed charge in the basic rate. These figures better isolate the incentive ratio changes due to increased time variation in rates. However, the key conclusions remain the same.

4. Discussion and Conclusions

We explored changes in EE, DPV, and building electrification customer electricity and energy bills across a large number of simulated building profiles in four regions under flat and time-based rates. The study captured heterogeneity in EE and DPV hourly savings shapes across different building technologies, measures, and PV system orientations, as well as the large differences in residential building characteristics (e.g., vintage, appliance saturation) and weather.

The study found no consistent relationship between customer bills under flat and time-based rate designs: in some cases, time-based rates increased bill savings relative to flat rates, while they decreased them in others. Our findings present a more nuanced relationship in which the magnitude of savings (or increase in electricity consumption in the case of building electrification), timing of those savings, and average prices matter more than the specific time-based nature of rates (e.g., whether the time-based rate is TOU vs. event-based). Specifically, for the three types of decarbonization technologies we explored, we found that:

- Changes in EE bill savings on average were small across the different combinations of rate designs, EE measures and packages, and utilities (i.e., less than 2 percentage points change in either direction). We found more instances where time-based rates eroded EE bill savings than increased EE bill savings. The erosion in bill savings was partly due to the lower compensation for off-peak savings under time-based rates compared to flat rates, which was a time period when EE measures produced a disproportionate amount of savings. For some rates, bill saving erosions were fully explained by the higher $/month fixed charge and the lower average $/kWh price that accompanied the time-based rates.
- The majority of changes in DPV bill savings were less than 2 percentage points across the different combinations of rate designs, PV system orientations, and utilities, with a slight tendency towards erosion of bill savings. The magnitude and direction of change in DPV bill savings were mostly explained by the difference in the average time-based $/kWh price and average flat $/kWh price.
- Changes in building electrification energy bills under flat rates vary noticeably by utility. The electrification package modeled in this study resulted in substantial energy savings from replacing older equipment with much higher efficiency heat pumps (in addition to efficiency gains from new ducting as part of a comprehensive retrofit package). Yet, despite reductions in building energy consumption, median customer energy bills for some utilities increased because of the higher price of electricity compared to fossil fuel prices.

The results have several implications for decision-makers interested in aligning retail rate design with the deployment of EE, DPV, and building electrification, especially in support of broader decarbonization goals. First, the risk of substantial bill increases under time-based rates for customers that invest in EE, DPV, and building electrification may be overstated. In most cases, the shift from flat to time-based rates resulted in very small changes in bill savings as a share of a customer's total bill.

Second, customers that have invested in EE and DPV may not be financially motivated to enroll in time-based rates, undermining efforts by decision-makers and utilities to encourage load shifting or shedding. The large majority of EE and DPV energy savings occurred in off-peak price periods when time-based rates typically discount prices. Furthermore, even for the customers with a particularly large share of savings in on-peak periods, the modest peak-to-off-peak price differentials among the rate designs we explored did not significantly enhance the value of peak period savings from EE and DPV.

Third, adjusting the average retail volumetric rate level may be more impactful than changing the temporal variation in volumetric rates for aligning compensation of EE and DPV investments with societal benefits. Notwithstanding the difficulty and complexity in changing average retail rate levels to match societal marginal costs, we found noticeable differences in the incentive ratios across utilities that were largely explained by differences in the average retail volumetric rate. Time-based rate designs generally did not change whether customer bill savings were greater or less than societal benefits (i.e., whether technologies were under- or over-incentivized). This suggests that from the perspective of achieving societal benefits, customers of utilities with high electricity prices have incentives to overinvest in EE and DPV; those of utilities with low electricity prices have incentive to underinvest.

Fourth, the finding that, among the rates in this study, average retail volumetric rate levels matter more than rate design as a driver of customer bill savings and alignment with societal benefits has implications for deployment of multiple decarbonization technologies. A lower average retail volumetric rate may minimize electricity bill increases for building electrification customers by reducing the difference between fossil fuel and electricity prices. However, the same decrease in average retail volumetric rate may reduce EE and DPV customer bill savings by lowering the value of electricity savings. These differential impacts imply that it is difficult—if not impossible—to increase incentives for all of these technologies through rate reform alone. This emphasizes the importance of setting rates to reflect social marginal costs and using additional incentives for any remaining misalignment in adoption incentives.

Finally, there are several future research opportunities to build on this study and further unpack the effects of changes in retail rate design on customer economics for investments in EE, DPV, and building electrification. First, incorporating natural gas, fuel oil, and propane marginal costs into the incentive ratios would assess alignment of building electrification customer energy bill changes with social marginal costs. Second, future studies might consider additional rate designs, particularly a greater reliance of fixed cost pricing, rates with much larger peak-to-off-peak price differentials, rate periods designed to align with technology load shapes and operational characteristics (e.g., heat pump load shapes), and RTP designs that fully reflect social marginal costs. Third, future analysis may also benefit from capturing the impacts of short-run customer price response in the form of energy conservation or load shifting. Fourth, a more thorough assessment of customer economics might incorporate equipment investment costs, including customer electrical panel and circuit upgrade costs for building electrification, and impacts of changes in rate design on customer decarbonization technology payback times.

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APPENDIX A. Electricity Rate Designs, LMP Data Sources, and Fixed Charge Normalization Methodology

To capture a variety of climates and power system conditions, we analyze EE, DPV, and building electrification investments in four regions: the Midwest, Southwest, Northeast, and Great Plains. We use generic electricity rates by adapting tariff data from four different utilities: Ameren in Illinois, Arizona Public Service (APS) in Arizona, Green Mountain Power (GMP) in Vermont, and Oklahoma Gas and Electric (OGE) in Oklahoma. We analyze a range of residential retail electricity rate designs presently offered by these four utilities and classify them into five categories: 1) "flat" rates that are time-invariant or vary only by season, 2) time-of- use (TOU) $/kilowatt-hour (kWh) rates that vary systematically by season, hour of day, and whether the day is a non-holiday weekday, 3) rates with coincident $/kilowatt (kW) demand charges where customers pay each month based on their maximum kW demand during certain hours of the day, 4) event-based rates that have higher prices during a small number of hours of the year when there is especially high system demand, and 5) real-time prices that change dynamically based on day-ahead market conditions.

We select available rates in 2019 for the four generic utilities. We collect tariff data for each utility that applies to any of the five rate categories mentioned above, leading to some overlap in time-of-use rates where available. For the collection, we include all fixed fees, such as meter, customer account and billing charges, as well as all volumetric charges, such as transmission, cost recovery adjustments (e.g., fuel adjustment clause), renewable energy adjustments, and additional charges. As applicable, we also calculate block schedule pricing schedules for individual buildings based on monthly consumption. Table A-1. provides a list of electricity rates used in our analysis.

Table A-1. Electricity rates used in the study

Region	Utility	Rate name	Rate type
Midwest	Ameren	Basic	Flat
Midwest	Ameren	Power Smart Pricing	Real time pricing
Southwest	APS	Basic	Flat
Southwest	APS	TOU-E	Time-of-use
Southwest	APS	R-2	Time-of-use + demand charges
Northeast	GMP	Basic	Flat
Northeast	GMP	R-9	Event
Northeast	GMP	R-11	Time-of-use
Northeast	GMP	R-14	Time-of-use + event
Great Plain	OGE	Basic	Flat
Great Plains	OGE	R-TOU	Time-of-use
Great Plains	OGE	R-VPP	Event

For the Northeast utility's critical peak pricing schedule, we determine which ten days have the highest peak load during the critical peak pricing period using the aggregate load from the Northeast utility load shape baseline. The 2019 variable peak price event schedule was provided by OGE. We used real-time locational marginal pricing (LMP) schedules for 2019 for the Midwest real-time pricing. Table A-2 provides the LMP nodal data sources used for each utility.

Table A-2. LMP data sources

Region	Utility	LMP node	LMP type
Midwest	Ameren	AMIL.ACL9	MISO-DAH

We also estimate the impact of a shift to time-based rates if fixed charges did not change. This isolates the impact of the time-based nature of the $/kWh variable rates from the change in average $/kWh variable rate levels. We calculate these counterfactual bill savings by estimating the following regression model for each utility:

$$\overline{Variable\ Rate_r} = \beta_0 + \beta_1 (Fixed\ Charge)_r + \beta_2 (Demand\ Charges)_r + \varepsilon_r$$

Where $\overline{Variable\ Rate_r}$ is the average $/kWh variable rate across all modeled ResStock customers under rate design r and baseline consumption, $(Fixed\ Charge)_r$ is the associated $/year fixed charge, and $(Demand\ Charges)_r$ are the total annual demand charges ResStock customers pay under rate r without any EE, DPV, or electrification.[36] In this model, β_1 reflects the $/kWh change in the average variable rate level that accompanies a $1 change in the fixed charge. We can, therefore, approximate a customer's bill savings under the baseline demand charge as:

$$\begin{aligned}(Normalized\ Bill\ Savings)_{iurp} &= (Bill\ Savings)_{iurp} \\ &+ \beta_1((Flat\ Fixed\ Charge)_u - (Fixed\ Charge)_{ur})(kWh\ Savings)_{iurp}\end{aligned}$$

Where $(Bill\ Savings)_{iurp}$ is the bill savings of customer i under utility u and rate design r from adopting EE, DPV, or electrification package p, $(Flat\ Fixed\ Charge)_u$ is the fixed charge under the flat rate for the corresponding utility, and $(kWh\ Savings)_{iurp}$ is the customer's annual kWh electricity savings from EE, DPV, or electrification.

[36] We estimate the model for all utilities simultaneously by using utility interaction terms.

APPENDIX B. Building Simulation (ResStock)

We use residential load profiles created using NREL's ResStock to estimate hourly baseline energy usage based on simulated building characteristics for current building technology deployment and appliance stock, as well as alternative technology deployment scenarios intended to represent increased EE and building electrification. Importantly, ResStock produces a representative sample of buildings across climate zones with a realistic diversity of building types, vintages, sizes, construction practices, installed equipment, and appliances. The hourly load shapes come from a physics-based simulation model that is calibrated and validated using empirical data on actual energy use in buildings, including metered utility data from more than 2.3 million customers throughout the country and circuit-level sub-metered data (Pigman et al., 2022[37]; Wilson et al., 2022). For this work, NREL provided annual hourly profiles for approximately 10,000 residential buildings (single-family detached homes only) per upgrade scenario using 2019 Actual Meteorological Year (AMY) weather data, which represents the most recent year where data is available.[38]

For each upgrade scenario, ResStock applies modified building characteristics and equipment to the same buildings modeled in the baseline scenario based on specifications for each upgrade scenario (see Table B-1.). The components of each upgrade scenario package were determined based on existing energy efficiency standards and commercially-available equipment alternatives. In order to represent a more realistic application of upgrade adoption, upgrades are applied deterministically to individual buildings based on their degree of efficiency in the baseline building stock (e.g., buildings with a lower level of efficiency in the baseline building stock receive a less efficient upgrade than a more efficiency building in the baseline building stock) . We use four of these packages for our analysis[39]:

- Electrification: The electrification package replaces non-electric space and water heating with electric alternatives, including heat pump water heaters and air-source heat pumps (both ducted and mini-split) for space heating, as well as non-electric clothes dryers and cooking ranges.[40] The package also includes improved ducting and energy efficiency upgrades of electric appliances, including clothes dryers and cooking ranges. For this package, we include all

[37] Pigman, M., Frick, N.M., Wilson, E., Parker A., and Present, E. (2022). End-Use Load Profiles for the U.S. Building Stock: Practical Guidance on Accessing and Using the Data. (available at: https://eta-publications.lbl.gov/sites/default/files/lbnl_eulp_2022_1208.pdf)

[38] For our analysis, we select a smaller sample from the 10,000 buildings provided per upgrade scenario in order to better represent the intended outcome of each upgrade type (e.g., we remove buildings with 100% electricity consumption in the baseline building stock for the electrification package since no fuel switching occurs for those buildings).

[39] For additional information about ResStock's development, data inputs, and modeling methodology, see Wilson et. al. (2022) "End-Use Load Profiles for the U.S. Building Stock: Methodology and Results of Model Calibration, Validation, and Uncertainty Quantification" (available at: *https://www.osti.gov/biblio/1854582/*)

[40] Heat pumps in the electrification package may result in an increase in cooling load for buildings without pre-existing air-conditioning.

buildings with at least one non-electric end use in the baseline (i.e., these buildings do not have 100% electric load in the baseline building stock).

- Equipment: The equipment package replaces existing electric air conditioning, space heating, water heating, refrigerators, clothes washers and dryers, and cooking ranges with more energy efficient alternatives.[41] For this package, we only include buildings with electric end uses in the baseline, meaning they have no additional consumption from other energy sources (i.e., these buildings have 100% electric load in the baseline building stock).
- Envelope: The envelope package improves attic and exterior wall insulation and adds exterior storm windows. We include all buildings in the baseline.
- Lighting: The lighting package replaces all existing light bulbs with light-emitting diodes (LEDs). For this package, we only include buildings with either incandescent or CFL lighting in the baseline.

[41] While buildings receiving the equipment upgrade package will generally exhibit a decrease in electricity consumption, they may show a net increase in total electricity consumption in cases where existing space heating is replaced by heat pumps for buildings without pre-existing air conditioning.

Table B-1. List of upgrade components in each ResStock modeled upgrade package

Package	Upgrade Components (Technology Performance/Efficiency Assumption)
Electrification	Air-source heat pump (SEER 22, 10 HSPF) Mini-split heat pump (SEER 25, 12.7 HSPF) Improved ducts (10% leakage, R-8) Heat pump water heaters (50-80 gallons, 3.35-3.45 UPF) Clothes washer (123 kWh/year) Clothes dryer (premium efficiency) Cooking range (induction range) Dishwasher (199 kWh/year) Refrigerator (EF 21.9)
Equipment	Air-source heat pump (SEER 22, 10 HSPF) Mini-split heat pump (SEER 25, 12.7 HSPF) Central air conditioning (SEER 18) Window air conditioning (EER 12) Improved ducts (10% leakage, R-8) Heat pump water heaters (50-80 gallons, 3.35-3.45 UPF) Clothes washer (123 kWh/year) Clothes dryer (premium efficiency) Cooking range (induction range) Dishwasher (199 kWh/year) Refrigerator (EF 21.9)
Envelope	Attic insulation (range from 2021 IECC R-values to R-60 depending on initial value, 13% reduction in whole-home infiltration reduction) Exterior wall insulation (additional R-6 exterior insulation for homes older than 1990, 19% whole-home infiltration reduction) Exterior storm windows (low-E storm windows added if existing double-pane metal frame or single pane windows)
Lighting	LED lighting (100% LED)

APPENDIX C. Social Marginal Cost Calculations

The following subsections describe the marginal avoided cost estimation in detail. Each of the first seven subsections covers one of the cost components outlined in Table 2. The last subsection presents summary statistics and figures of the resulting marginal cost estimates, including breakdowns by cost component.

Energy, Transmission Losses, and Transmission Congestion Costs

Three of the utilities in our analysis participate in wholesale electricity markets run by a Regional Transmission Operator (RTO) or an Independent System Operator (ISO). We use 2019 hourly real-time locational marginal prices (LMPs) from SNL Financial as an estimate of the combined marginal costs of electricity generation, scaled up for transmission losses, and congestion on the transmission lines. We choose the ISO New England aggregated node.Z.VERMONT for the Northeast utility, the Midcontinent ISO node AMIL.ACL9 for the Midwest utility, and the Southwest Power Pool aggregated node OKGE_OKGE for the Great Plains utility. Assuming there is no market power or other market distortions and the total amount of generating capacity in the system is fixed, these LMPs should reflect the combined marginal costs of electricity generation, transmission losses, and transmission congestion.

For the vertically-integrated Southwest utility, we use Federal Energy Regulatory Commission (FERC) Form-714 hourly system lambda values, which we accessed through Ventyx. These are utility estimates of the private cost of increasing electricity production by one MWh in a given hour. In other words, these are the utility's estimates of energy marginal costs. Following Borenstein and Bushnell, we scale the lambda values up by 2% for transmission losses. We do not estimate congestion costs for the Southwest utility.

Table C-1. displays summary statistics of these LMPs and system lambda values, and Figure C-1. displays averages by season and hour of day. The prices for the Northeast utility tend to be highest in the winter and in the early evening. Prices for the Midwest and Great Plains utilities tend to be highest in the summer late afternoons. The Southwest utility system lambda values vary less seasonally and across hours of the day than the LMPs in the other three locations.

Table C-1. LMPs and system lambda value summary statistics ($/MWh)

Percentile	Midwest	Southwest	Northeast	Great Plains
5th	15.4	8.8	13	-2.2
25th	20.2	15.1	18.7	14.1
50th	22.6	19	24.1	18.6
75th	25.8	21.7	35.3	23.4
95th	39.3	31.4	66.9	52.7

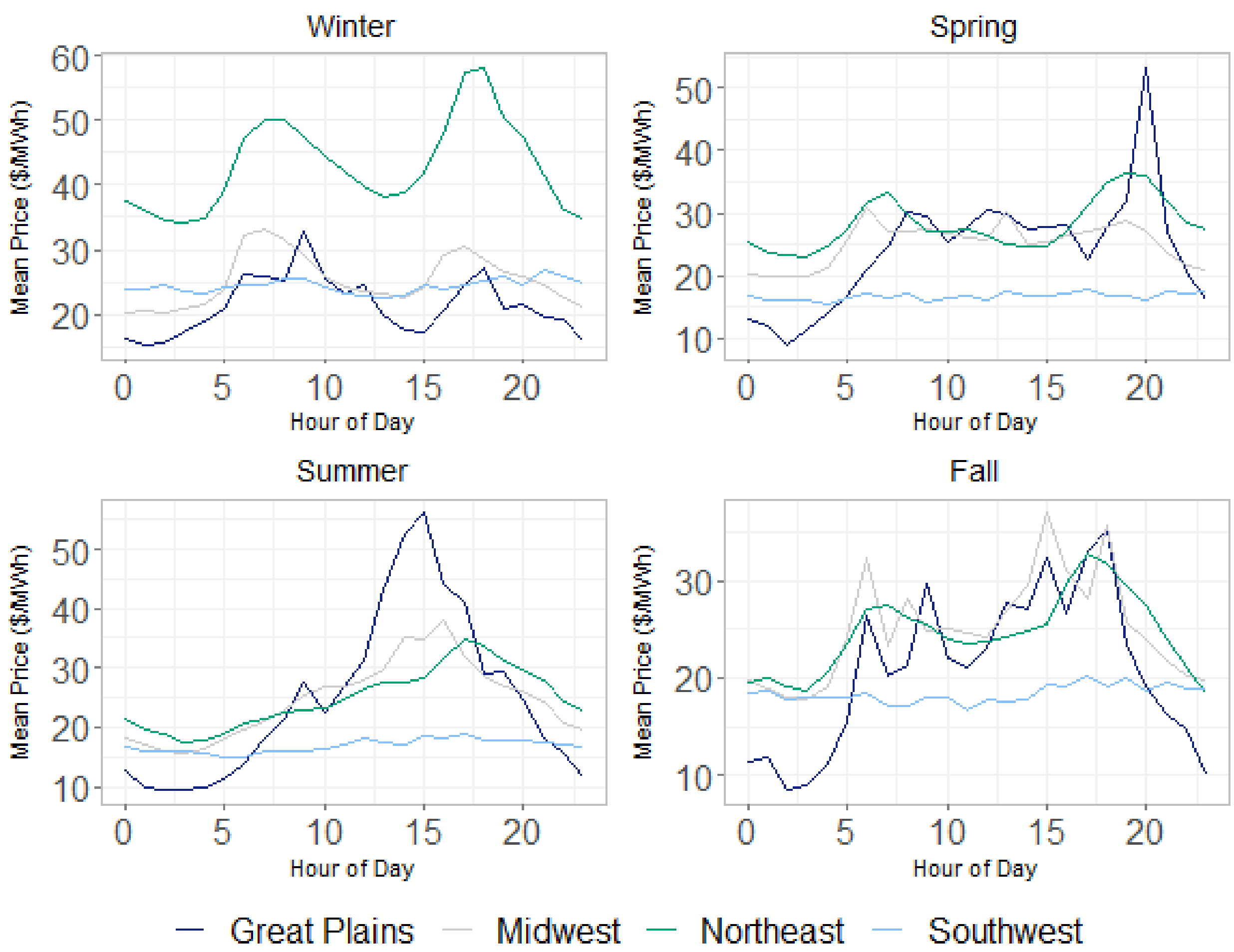

Figure C-1. Average LMP and system lambda values by utility, season, and hour of day

<u>Ancillary Services Costs</u>

Ancillary services are non-energy services typically provided by generators to improve grid reliability. Most ancillary services help ensure that generation sufficiently matches real-time electricity usage at all times. Marginal ancillary service costs reflect the impact of 1 additional kWh of electricity usage on the costs of providing ancillary services. We use the E3 2019 Avoided Cost Calculator (ACC) assumption that marginal ancillary service costs are 0.9% of marginal energy costs. This value comes from a historical comparison of energy and ancillary service costs in the California ISO market. This approach implicitly assumes that ancillary service requirements are linear in system-wide electricity usage, at least near typical electricity usage levels.

<u>Distribution Losses</u>

In addition to transmission system electrical losses, there are also distribution system electrical losses and theft within the distribution system. Borenstein and Bushnell estimate hourly marginal distribution losses for each U.S. investor-owned utility for the years 2014 through 2016. We use their estimates of average annual losses for the four utilities in our analysis to compute 2019 values. We follow their assumption that 25% of losses are fixed and do not vary with electricity usage. The remaining 75% of these losses vary with the square of electricity usage. As shown in Equations 5 and 6 of the Borenstein and Bushnell Appendix, this assumption allows us to estimate marginal hourly distribution losses as:

$$Marginal\ Losses = 2 \times .75(Average\ Annual\ Losses)_i \frac{\sum_{t=1}^{8760} Q_{it}}{\sum_{t=1}^{8760} Q_{it}^2} Q_{it}$$

where Q_{it} denotes total electricity usage for utility i in hour t. The summations sum over all hours of the 2019 year, which we index from 1 to 8760. For hourly electricity usage estimates, we use 2019 FERC 714 Planning Area Load filings.

Table C-2. shows the resulting mean marginal loss estimates by utility. Table C-2. also includes the average annual losses for comparison. To translate loss factors to $/kWh marginal costs, we multiply marginal losses by the sum of energy and external marginal costs in each hour.

Table C-2. Mean marginal and average distribution losses by utility

	Midwest	Southwest	Northeast	Great Plains
Mean Marginal Losses	9.95%	9.42%	9.38%	9.04%
Average Losses	6.83%	6.85%	6.47%	6.28%

<u>Generation Capacity</u>

Generation capacity marginal costs reflect the net incremental cost of building a new generator due to an increase in electricity demand during peak system hours. Generation capacity is innately a lumpy investment. Under most circumstances, meeting a small increase in peak load will not require building any new generation. Occasionally, a small increase in peak load will lead to investment in a large new generator with capacity orders of magnitude greater than the increase in load. We smooth out this investment decision and treat generation capacity decisions as continuous, allowing arbitrarily small increases in generation capacity to meet small increases in peak load. We also assume that systemwide electricity generation is increasing over time, so a marginal reduction in electricity usage can delay an investment in new generation capacity.

The Independent System Operator of New England (ISO-NE) runs a market for generation capacity. For the Northeast utility, we estimate the annual marginal generation capacity cost as the annual $/kW ISO-NE forward capacity auction price. This is the price per kW paid to generators for being available to generate during peak hours. ISO-NE conducts capacity auctions three years ahead of the commitment period. They determine future capacity need based on historical electricity demand. Since we are considering the impact of an unexpected marginal change in 2019 electricity usage, we use the auction-clearing price from the annual Forward Capacity Auction #13, which was conducted in 2019 for capacity commitment period 2022/2023.

The other three utilities do not participate in capacity markets. For these utilities, we follow the E3 2019 ACC approach and calculate net capacity cost as gross costs less the profit that a new single-cycle combustion turbine generator could make in the wholesale energy and ancillary services markets. The intuition for this approach comes from the fact that the past costs of building existing generators are sunk. When the new generator enters the wholesale energy and ancillary services markets, it earns profit whenever its costs are below market-clearing prices. This displaces profit that other generators would have otherwise earned in the market. In aggregate, these profit changes offset each other and do not produce any net societal costs. However, the fact that the new generator anticipates earning revenue in the wholesale markets enables ratepayers and utility shareholders to pay less than the full gross costs of building the generator. Our calculation of marginal cost aims to estimate these required payments.

We assume that the change in generation capacity is small enough to not change wholesale market prices. To the extent that the generator's entry would cause a reduction in wholesale electricity prices, this benefit would be offset by a commensurate decrease in the generator's profit, which would reduce the net cost of new capacity. On net, we assume the impact of any market price suppression on societal costs would be negligible.

We use the E3 2019 ACC estimate of the gross annualized fixed cost of building a new simple cycle combustion turbine, \$163.92/kW-yr. To calculate generator revenue in non-capacity markets, we first calculate whether the generator would operate in each hour, ignoring any dynamic considerations, such as start-up costs. We assume the generator will operate in a given hour if the wholesale energy price is above the variable operating costs, i.e.,

$$(Natural\ gas\ fuel\ costs_h + Variable\ O\&M\ cost) < LMP_h/(1 + Transmission\ loss\ factor)$$

where the righthand side of the inequality reflects our estimate of energy prices. We use the E3 2019 ACC variable operation and maintenance (O&M) estimate, which is \$5.52/MWh in 2019 dollars and the Borenstein and Bushnell (2019) transmission loss factor of 2%. We estimate hourly natural gas costs using monthly state citygate natural gas prices from the U.S. Energy Information Administration (EIA) and E3 2019 ACC assumptions about the assumed heat rate of the marginal generator. We allow the generator's heat rate to vary with hourly temperature. To estimate this relationship, we use the E3 2019 ACC temperature derate curves and actual 2019 temperature from the U.S. National Oceanic and Atmospheric Administration (NOAA) Integrated Surface Database. We estimate average daytime temperature by month for each utility using the E3 2019 ACC definition of daytime hours. We extend the E3 2019 ACC temperature derate curves linearly a few extra degrees to capture particularly high temperatures in the Southwest utility's service area.

After determining whether the marginal generator would operate in each hour, we calculate the profit the generator would earn in the wholesale energy market in each hour by using the same variable operating costs and estimated energy prices used to determine the operation decision. We use the E3 2019 ACC assumption that ancillary service revenues are 2.7% of the generator's wholesale energy revenues. We subtract the variable costs from the combined revenues, adjusting for the impact of temperature on the generator's output. We use the E3 2019 ACC outage factor of 7.3% to derate this profit value for generator outages. This leads to the following profit equation:

$$\text{Profit} = \left[\sum\nolimits_{\text{h in operating hours}} \left(1.027\left(\frac{\text{LMP}}{1-\text{Transmission Loss Factor}}\right) - (\text{Operating Costs})_{\text{h}}\right)(\text{Temperature Output Derate})_{\text{h}}\right] \times (1 - \text{Outage Factor})$$

To calculate annual generation capacity costs, we subtract this profit value from the annualized fixed capital costs. We scale this net value up for losses during the peak system hour. This provides the cost if the generator operated at its nameplate capacity during the peak hour. We also make a temperature derate adjustment to convert this value to cost per delivered peak capacity. This produces the following formula:

$$\begin{aligned} & \mathit{Marginal\ Generation\ Capacity\ Cost} \\ & \qquad = [\mathit{Annualized\ Fixed\ Costs} - \mathit{Profit}] \\ & \qquad * (\mathit{Peak\ Loss\ Factor})/(\mathit{Average\ Output\ Derate}) \end{aligned}$$

Conceptually, we should only apply this marginal capacity cost in the peak demand hour. In practice, the precise hour of the year in which peak demand occurs differs year-to-year depending on weather among other factors. To avoid overfitting our estimates to the 2019 calendar year, we spread out the capacity cost over 40 hours of the year. We allocate costs equally to the 40 hours of the year with the highest aggregate electricity usage. More sophisticated methods exist to estimate the probability that peak demand will occur in any given hour. This simple method of allocating costs across the top hours is appropriate in our setting because we compare these marginal costs to rates that are designed years in advance of their implementation when it is difficult to predict the relative demand levels in the most constrained hours.

<u>Distribution Capacity Costs</u>

Distribution capacity costs capture the expected costs of a distribution system upgrade to accommodate higher electricity consumption levels. Since distribution capacity expansion is lumpy, the true marginal impact of a 1 kWh load increase is likely to be very large in a few hours and locations and zero otherwise. We do not attempt to estimate this geographic heterogeneity in distribution capacity marginal costs. Instead, we aim to estimate an average marginal cost value across all residential customers in each hour. To achieve this, we use the average avoided distribution cost of $48.37/kW-yr from the Mendota Group LLC (2014) literature review of 35 utility estimates. We allocate this value to the 200 hours of the year with the highest estimated load on residential feeders (SDG&E 2017). We use aggregate ResStock electricity usage for each utility to determine these 200 hours.

There are a few assumptions worth highlighting. First, our analysis applies marginal costs to reductions in load. In doing so, we implicitly assume a symmetry in all marginal cost components that makes increases and reductions in electricity usage have equal and opposite effects on societal costs. This is a reasonable assumption if other electricity usage on the relevant feeders is increasing over time, which is stronger than the generation capacity assumption that systemwide electricity usage increases over time. Under this assumption, the load reductions we analyze are effectively slowing down this aggregate increase in electricity usage and, thereby, delaying a distribution upgrade for some marginal amount of time. Second, distributed PV may also conceivably cause distribution upgrades at large enough penetrations. We assume these costs are zero and apply the same marginal distribution capacity costs to distributed PV and energy efficiency.

Renewable Portfolio Standard Costs

Three of the utilities in the analysis have to meet a minimum percentage of their retail sales with renewable generation due to a state Renewable Portfolio Standard (RPS) or Renewable Energy Standard. Since these two types of standards have the same structure, we will refer to both of them by the acronym RPS. If it costs more to generate electricity with renewable resources that comply with an RPS standard than to generate the same amount of electricity with the least-cost portfolio of resources, then an additional kWh of electricity usage increases the cost of complying with the RPS. The RPS marginal cost captures this incremental private cost. We assume that the RPS is binding, so meeting the incremental RPS obligation requires building new renewable generating capacity.
We calculate RPS costs using the following formula:

$$
\begin{aligned}
(PPA\ Price\ +\ &Integration\ Cost\\
&+\ Transmission\ Cost - (Energy\ Market\ Revenue)\ - (Capacity\ Revenue))\\
&\times (RPS\ Compliance\ Obligation)
\end{aligned}
$$

where PPA price is the price of a utility power purchase agreement (PPA) for renewable generation, integration cost captures the cost of additional reserves needed to meet grid reliability goals due to the intermittency of renewable generation, and transmission cost is the cost of building new transmission to connect the renewable generators to the rest of the grid as well as any other transmission upgrades needed to deliver the electricity to end users. We subtract out revenues that the RPS generator could make in wholesale energy and capacity markets and from payments for providing resource adequacy in areas without capacity markets. We multiply the net costs by the compliance obligation specified in the state RPS. For example, the Arizona RPS required the Southwest utility to meet 9% of its retail sales with renewable generation, so the RPS compliance obligation is 9%. This calculation follows pre-2019 versions of the E3 ACC approach closely. The one departure is that we do not deduct an emissions value from the PPA price. We separately capture carbon and local air pollution benefits from an RPS in our estimates of marginal carbon and environmental damages.

Table C-3. displays the 2019 RPS compliance obligations for the four utilities in our analysis. RPS-qualifying resources differ somewhat by state, but we assume the marginal resource is either wind or solar for all utilities. One state has different minimum percentages (“carve outs”) for each of wind and solar. Some states also have distributed generation carve outs. We neither increase compliance costs for any distributed generation carve outs nor allow distributed PV in our analysis to receive credit for their contribution to the RPS.

Table C-3. Utility Renewable Portfolio Standard compliance obligations

	Midwest	Southwest	Northeast	Great Plains
Total Obligation (% of Retail Sales)	14.5%	9.0%	57.67%	N/A
Wind Carve Out (% of Retail Sales)	10.875%	N/A	N/A	N/A
Solar Carve Out (% of Retail Sales)	0.87%	N/A	N/A	N/A

We assume the cost of RPS grid integration is $5/MWh in 2014 dollars based on a literature review by Luckow et al. (2015). We use a levelized transmission cost of $5/MWh in 2018 dollars, which is the mean and median of the estimates from Gorman et al. (2019). For PPA prices, we use the cheaper of the solar and wind PPA price estimates from Wiser et al. (2022) and Bolinger et al. (2022) in each region. For the Midwest utility, we assume the wind and solar carve outs are met and select the cheaper resource for the remaining compliance obligation. Table C-4. shows the cheaper marginal resource and the resulting PPA price by utility, converted to 2019 dollars. These values come from executed PPAs and embed tax incentives, including the Investment Tax Credit and the Production Tax Credit.

Table C-4. Power purchase agreement resource and price assumptions

	Midwest	Southwest	Northeast	Great Plains
PPA Resource	Wind	Solar	Wind	Wind
PPA Price ($/MWh)	27.6	23.5	42.6	14.7

We estimate energy and capacity revenues by multiplying our hourly energy and capacity marginal costs by estimated hourly renewable generation, which we normalize to 1 kWh of generation over the entire year. We use Lawrence Berkeley National Laboratory's Renewables and Wholesale Electricity Prices (ReWEP) Tool for wind generation profiles. For solar PV generation profiles, we use NREL's Solar Power Data for Integration Studies. We selected the utility scale PV profiles located closest to Springfield IL, Phoenix AZ, Burlington VT, and Oklahoma City OK for the Midwest, Southeast, Northeast, and Great Plains utilities, respectively. The database does not include any utility scale PV shapes in Vermont, so we use a distributed PV shape, which is assumed to be a fixed tilt system instead of having single axis tracking. For simplicity, we assume the amount of renewable generation is known with certainty. In practice, a renewable generator's contribution to capacity is highly uncertain and capacity payments may reflect this uncertainty.

Carbon and Local Air Pollution Costs

Electric generation also emits pollutants that may cause humans harm through climate- and health-related impacts, among other factors. We consider the marginal effect of electric generation on external damages caused by carbon dioxide (CO_2), sulphur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter smaller than 2.5 micrometers. Our approach does not capture the impact of electricity usage on emissions from any source except electric generator smokestacks. We use estimates of the impact of a 1 kWh increase in electricity usage on carbon- and criteria pollutant-related damages by region and load tercile from Borenstein and Bushnell. Borenstein and Bushnell segment the U.S. into nine regions they call North American Electric Reliability Corporation (NERC) subregions. These regions are similar to NERC electric reliability organization regions. The Borenstein and Bushnell estimates are the product of two values: the effect of an increase in electricity usage on pollutant emissions and estimated damages per ton of pollutant emitted. Borenstein and Bushnell estimate the impact of an increase in electricity usage in one region on electricity generator smokestack emissions in that and other regions empirically using historical NERC subregion electricity usage and power plant emissions data. The damages per ton underlying the Borenstein and Bushnell estimates come from the AP3 integrated assessment air pollution model (Clay et al. 2018, Holland et al. 2016). These damage estimates aim to capture the effect of emissions on ambient pollutant concentrations and the monetary impact of ambient air pollution on human wellbeing measured by human health, crop and timber yields, degradation of buildings and material, visibility, and recreation.

To calculate 2019 hourly external costs, we first calculate NERC subregion load in each hour of 2019 by adding FERC Form 714 electricity usage for all planning regions in the NERC subregion. For cases where a planning region crosses NERC subregion borders, we allocate the entire planning region load to the NERC subregion that contains the majority of the planning region. We also split MISO electricity usage equally between the SPP, SERC, and MRO subregions. For each subregion and hour of year, we then identify whether electricity usage was in the bottom, middle, or top tercile of the distribution of 2019 hourly electricity usage. Combining this information with the Borenstein and Bushnell estimates, adjusted for inflation, gives us hourly external CO_2 and criteria pollutant marginal costs for each utility.

We make two assumptions to calculate the CO_2 damage estimates. First, we use Borenstein and Bushnell's estimated social cost of carbon of $50 per metric ton in 2016 dollars.[42] Second, the Northeast utility private energy marginal cost estimates include the cost of compliance with the Regional Greenhouse Gas Initiative (RGGI). To avoid double counting, we subtract the average 2019 RGGI permit price from the Northeast utility carbon damage estimates.

<u>Marginal Cost Estimates</u>

Figure C-2. displays the resulting mean annual social marginal costs by cost component and utility. The largest private marginal cost components are energy and generation capacity costs. These costs are negatively correlated since higher energy prices reduce the capacity payments needed to incentivize construction of a generator or retirement of an existing generator. Capacity payments also tend to be higher in hotter areas since the temperatures reduce generator efficiency. We estimate that external marginal costs range from 58% to 118% of private marginal costs across the four locations. The variation in CO_2 costs across utilities reflects differences in which resources tend to have the marginal bid in wholesale electricity markets and differences in thermal generator heat rates across utilities. The

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[42] A higher social cost of carbon, such as the estimates outlined by the US Environmental Protection Agency in a November 2023 report (EPA 2023), would result in higher social marginal costs and lower incentive ratios. To facilitate sensitivity analysis, Figure C-2 depicts the share of carbon-related marginal costs relative to total social marginal costs. In non-RGGI regions, this marginal cost component scales linearly with the social cost of carbon.

air quality marginal costs largely depend on these factors and population density near the pollution-emitting generators. This explains why utilities in areas with relatively low population density, such as the Southwest utility, may have relatively high CO_2 marginal costs and relatively low air quality-related marginal costs. We estimate that renewable resources have reached parity with thermal resources in some utility service areas. This may change with the removal of tax credits and higher RPS obligations in these areas.

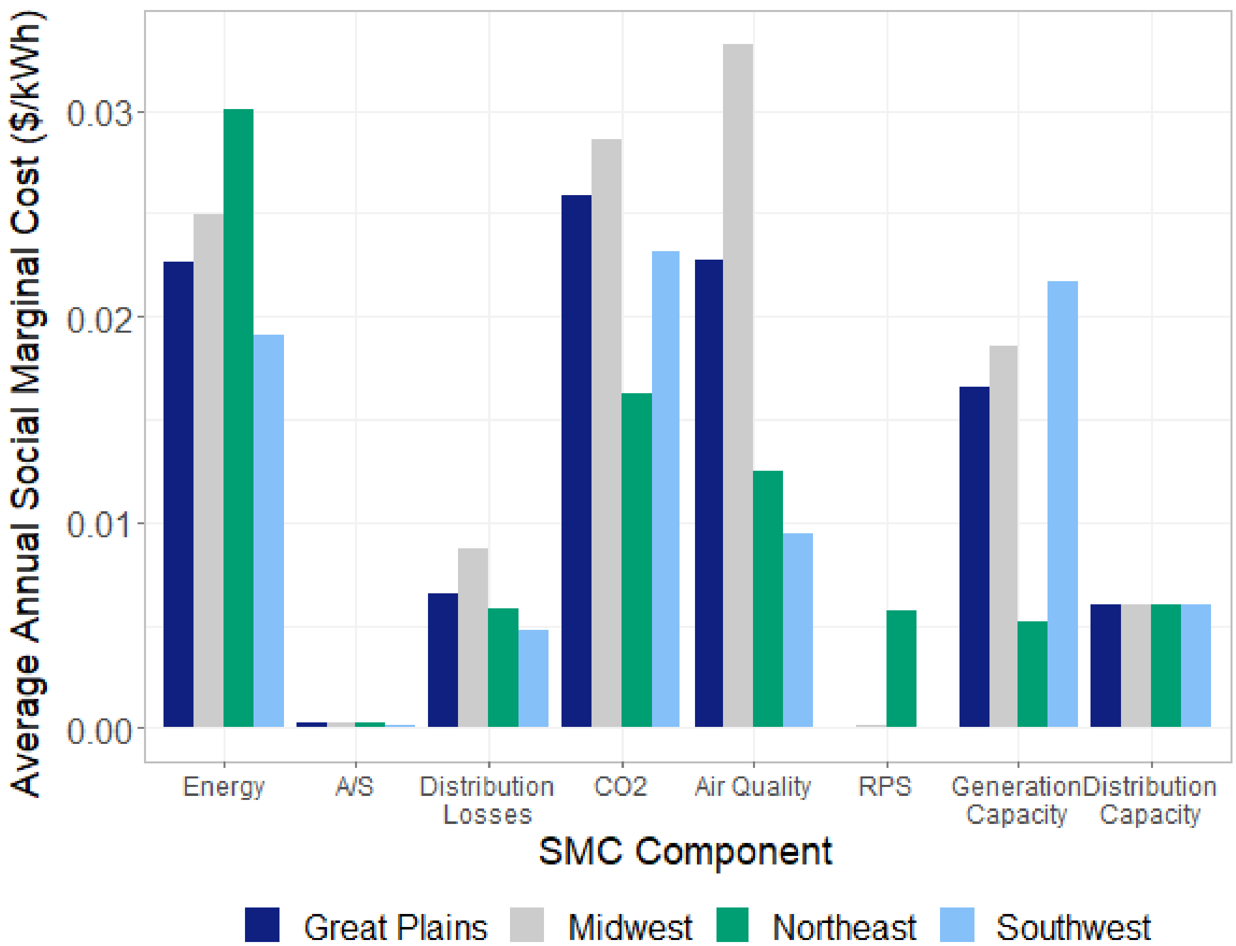


Figure C-2. Average annual social marginal costs by utility and cost component

Figure C-3.Figure C-4.Figure C-5.Figure C-6. break these annual estimates down temporally for each utility. The figures show average social marginal costs by season and hour of day. Generation capacity is especially seasonal with values concentrated in summer and winter months for the Northeast utility and in the summer and early fall months for the other three utilities. RPS costs are constant throughout the year. External marginal costs tend to be largest during high load hours for the Northeast and Midwest utilities and during low load hours for the Southwest and Great Plains utilities. The other marginal cost components tend to move with electricity usage. Costs tend to be highest in the morning and evening in winter months and in the late afternoon in summer months. This is not the case for the Southwest utility, which may be due to data quality issues in the system lambda estimates.

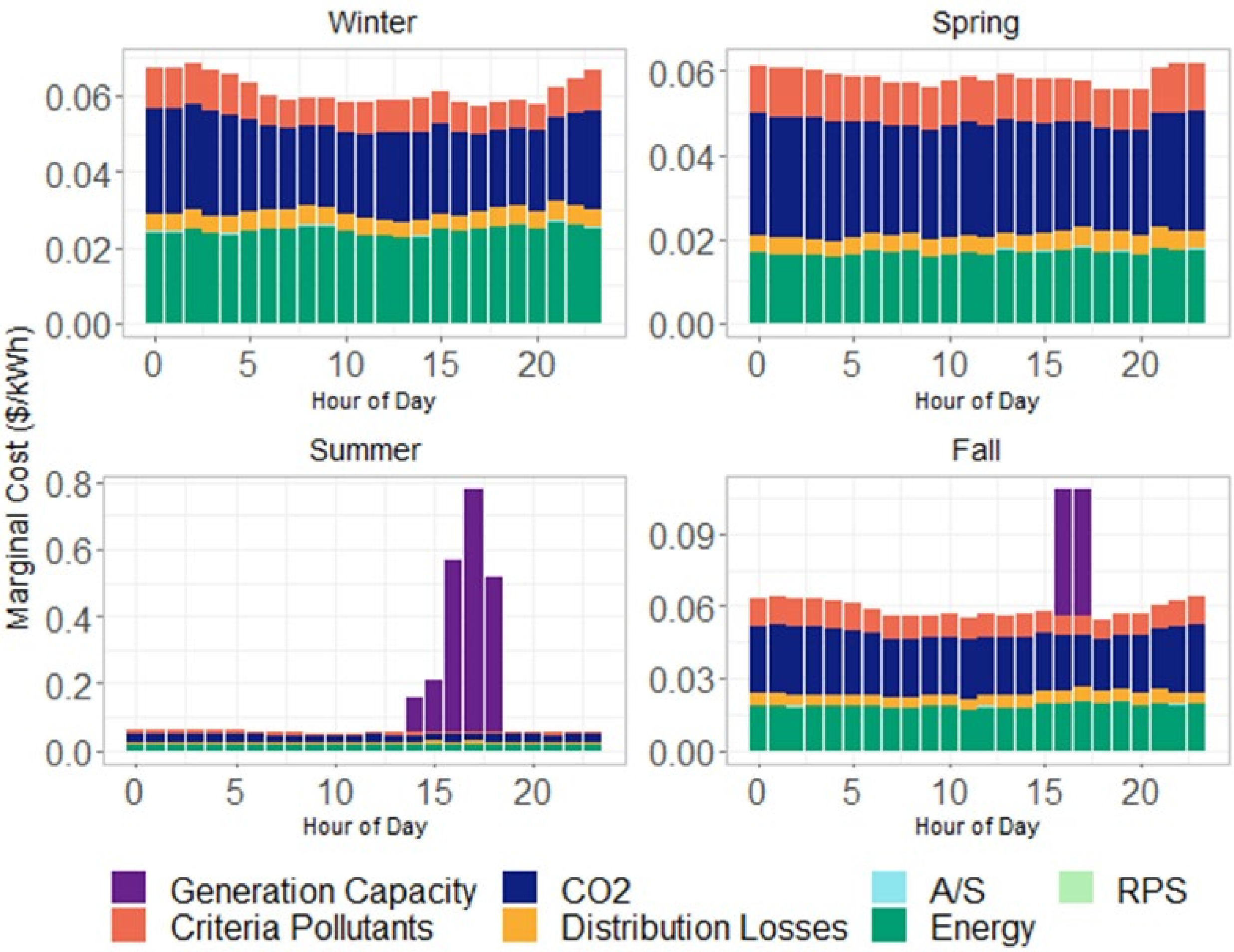


Figure C-3. Social marginal costs by season, hour of day, and component: Southwest Utility

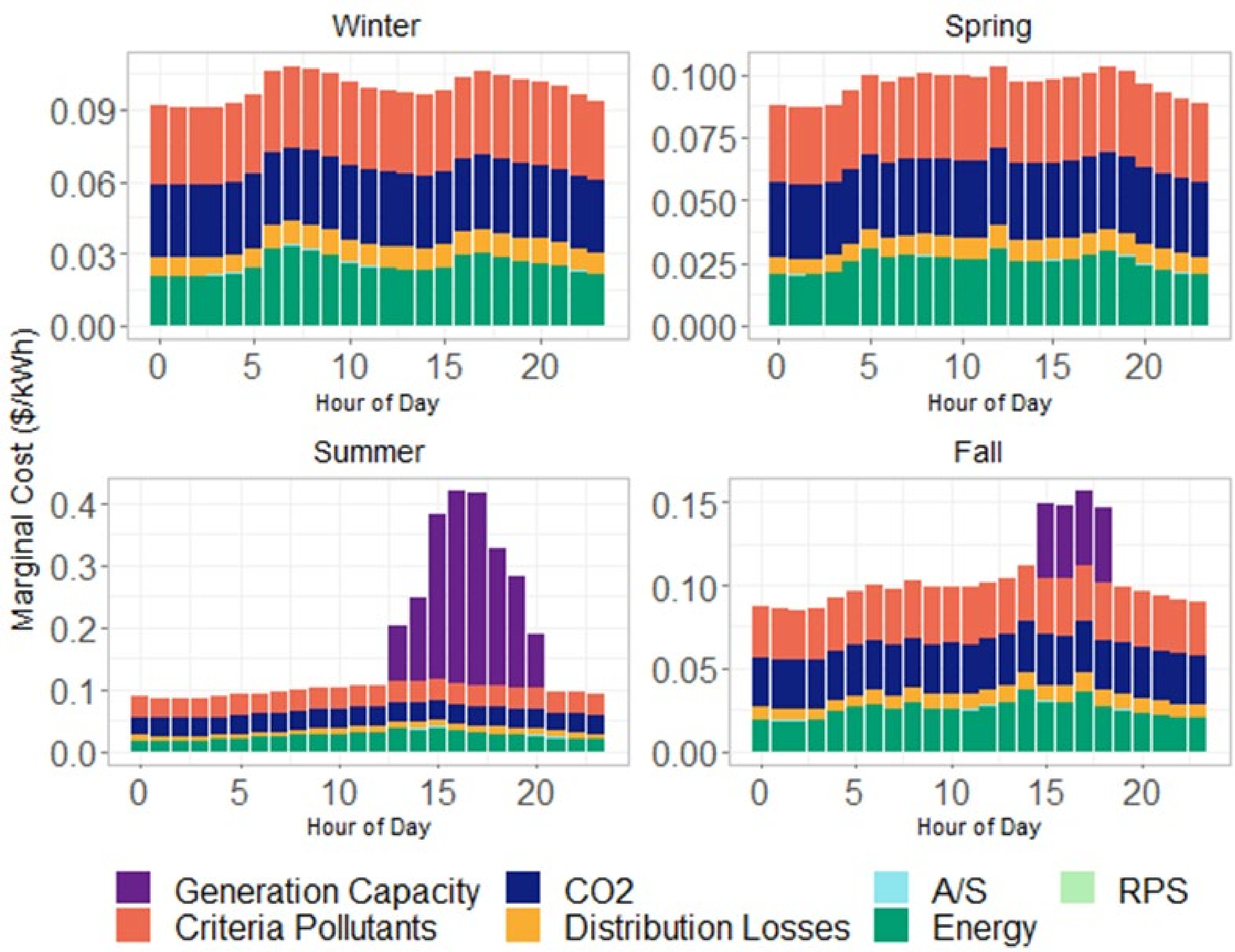


Figure C-4. Social marginal costs by season, hour of day, and component: Midwest Utility

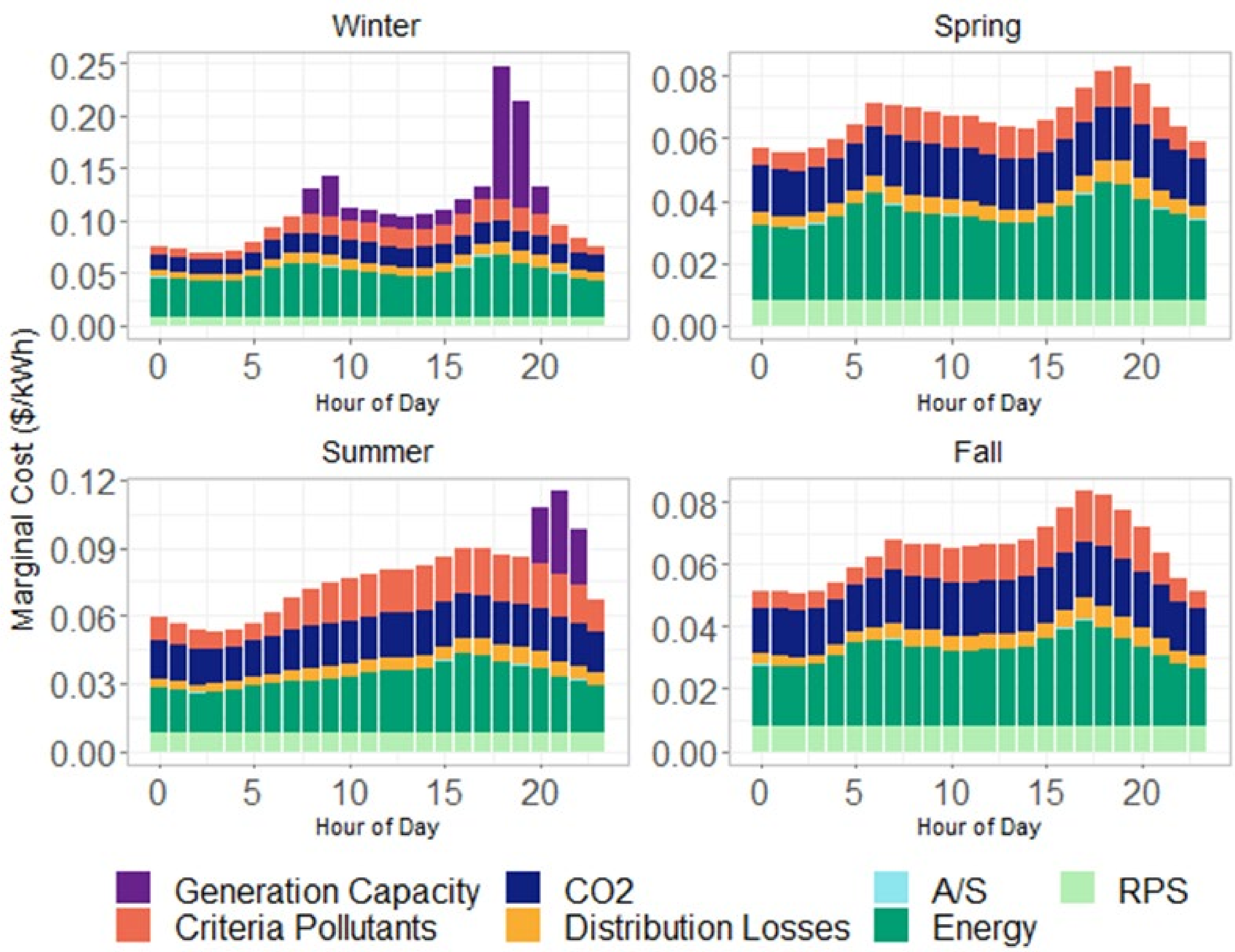


Figure C-5. Social marginal costs by season, hour of day, and component: Northeast Utility

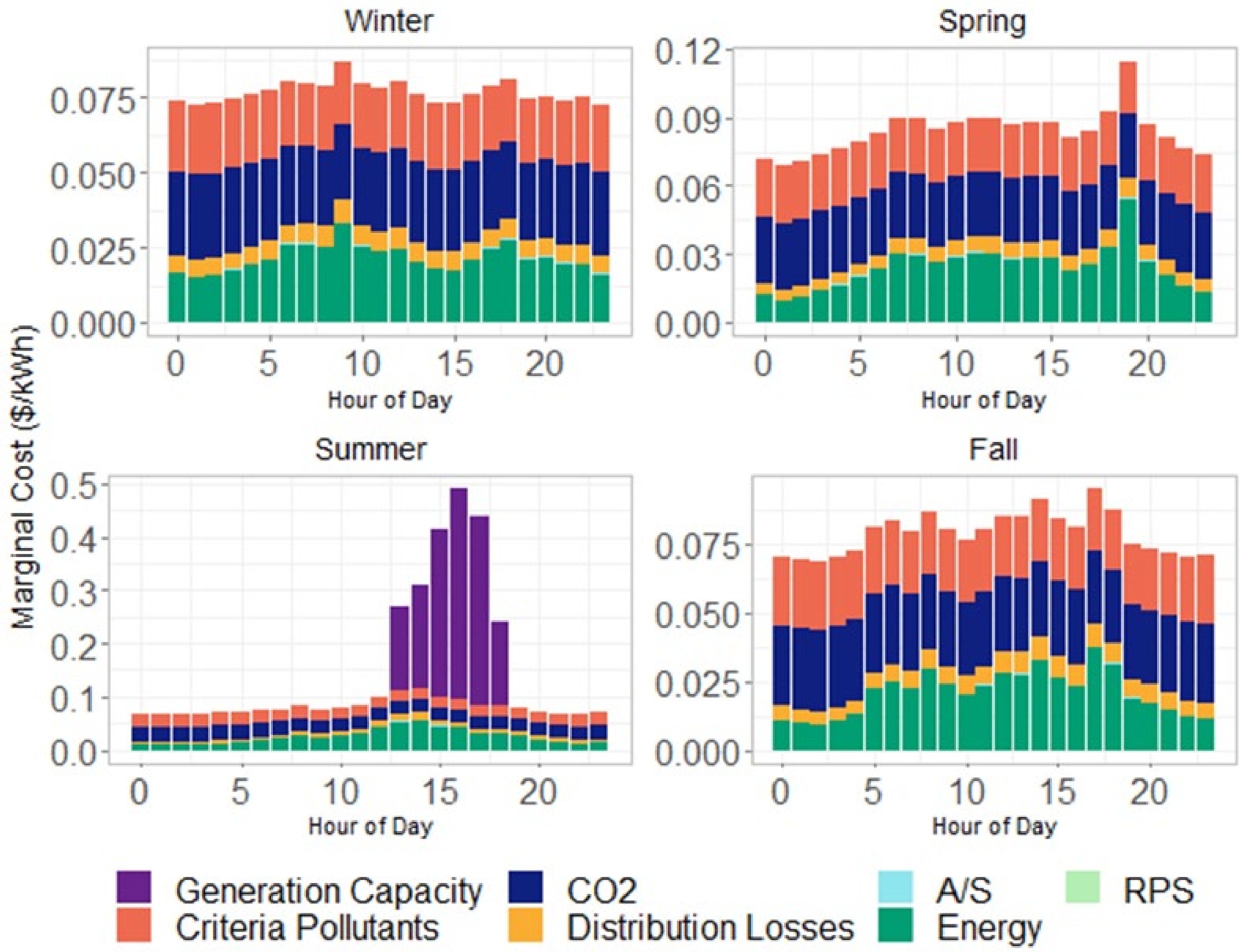


Figure C-6. Social marginal costs by season, hour of day, and component: Great Plains Utility

APPENDIX D. Incentive Ratio Driver Analysis

We analyze the relative welfare impacts of time-based rate design and the default average variable rate level. Average variable electricity rates frequently differ from average social marginal costs, which can contribute to over- or under-investment of GHG-reducing technologies (Borenstein and Bushnell 2022b, Novan and Smith 2018). We estimate these deviations of average variable basic rates from social marginal costs. We also calculate the Pearson correlation coefficient between social marginal costs and hourly \$/kWh and \$/kW prices. We compare the importance of time-based rate design relative to basic variable rate levels for economic efficiency by estimating the following models:

$$(Overinvest)_{ijur} = \beta_1(Avg\ Flat\ Rate)_u + \beta_2 cor\left(p_{iur}^{kWh}, (AC)_{iju}\right) + \beta_3 cor\left(p_{ur}^{kW}, (AC)_{iju}\right) + \varepsilon_{ijur}$$

And

$$\left|(Savings)_{ijur} - AC_{iju}\right| = \beta_1\left|(Avg\ Flat\ Rate)_u - AC_{iju}\right| + \beta_2 cor\left(p_{iur}^{kWh}, (AC)_{iju}\right) + \beta_3 cor\left(p_{ur}^{kW}, (AC)_{iju}\right) + \epsilon_{ijur}$$

where $(Savings)_{ijur}$ is the per-kWh bill savings for customer *i* in utility *u* from making investment type *j* under time-based rate schedule *r*, AC_{iju} is the associated per-kWh societal avoided costs, $(Overinvest)_{ijur}$ equals one if $(Savings)_{ijurs} > AC_{iju}$ and zero otherwise, $cor(p_{ur}^{kWh}, (AC)_{iju})$ is the Pearson correlation coefficient of the \$/kWh hourly variable price and hourly \$/kWh avoided costs, $cor(p_{ur}^{kW}, (AC)_{iju})$ is the Pearson correlation coefficient of the hourly \$/kWh avoided costs and the maximum possible applicable \$/kW demand charge in that hour, and $\varepsilon_{ijur}$and ϵ_{ijur} are normally-distributed error terms. We cluster standard errors at the investment-utility-rate level. To reduce the influence of outlier households, we exclude observations with values of bill savings less avoided costs above the 99th percentile and below the 1st percentile.

The results imply that average rate level also has a larger impact than rate design on whether there is overinvestment and the deviation of bill savings from avoided costs (``incentive deviation"). Column 1 in Table D-1 displays estimates of the linear probability model of whether there is over-investment, and Columns 2 and 3 display estimates from the same model, restricting the coefficient on price to zero and restricting the coefficients on all four rate design variables to zero, respectively. Comparing the adjusted $\boldsymbol{R^2}$ values from these models confirms that average \$/kWh price under the basic rate is a stronger predictor of over-investment than all four rate design variables combined. Average price can explain about 39% of the variation in whether an individual household over-invests in energy efficiency, while the correlations between the rate design components and social marginal costs together only explain 1% of this variation. Table D-2 displays estimates of the model of incentive deviation. Columns 1-3 show that the distance between the average rate and avoided costs is also a stronger predictor of investment economic inefficiency than how well the variable rates reflect temporal variation in social marginal costs. Columns 4-6 in Table D-1

Table D-2.suggest that these results translate to PV.

Table D-1. Over-investment regression results

	Dependent variable: Over-investment					
	EE			DPV		
	(1)	(2)	(3)	(4)	(5)	(6)
Flat Price ($/kWh)	7.335***		7.718***	9.272***		9.201***
	(0.821)		(0.611)	(0.428)		(0.379)
cor($/kWh Price, Avoided Costs)	−0.381	−1.515***		0.269	−1.118**	
	(0.294)	(0.440)		(0.185)	(0.504)	
cor($/kW Price, Avoided Costs)	0.793	0.247		−3.091***	−3.944***	
	(1.505)	(1.579)		(0.200)	(0.580)	
Constant	x	x	x	x	x	x
Observations	205,209	205,209	205,209	355,572	355,572	355,572
Adjusted R^2	0.543	0.149	0.532	0.798	0.163	0.746

Note: *p<0.1; **p<0.05; ***p<0.01. Standard errors clustered by utility, rate, and energy efficiency investment package (columns 1-3) or DPV orientation (columns 4-6).

Table D-2. Incentive deviation regression results

	Dependent variable: | Bill Savings - Avoided Costs |					
	EE			DPV		
	(1)	(2)	(3)	(4)	(5)	(6)
| Flat Price - Avoided Costs |	0.359***		0.370***	0.912***		0.823***
	(0.066)		(0.063)	(0.077)		(0.076)
cor($/kWh Price, Avoided Costs)	−0.001	0.010		0.012	0.030	
	(0.040)	(0.040)		(0.027)	(0.038)	
cor($/kW Price, Avoided Costs)	−0.026	−0.178***		0.199**	−0.207**	
	(0.069)	(0.065)		(0.094)	(0.090)	
Constant	x	x	x	x	x	x
Observations	205,209	205,209	205,209	352,781	352,781	352,781
Adjusted R^2	0.153	0.040	0.153	0.553	0.041	0.526

Note: *p<0.1; **p<0.05; ***p<0.01. Standard errors clustered by utility, rate, and energy efficiency investment package (columns 1-3) or DPV orientation (columns 4-6).

APPENDIX E. Supplemental Tables and Figures

Rate Summary Statistics

Table E-1. Rate summary statistics

Utility	Rate Name	Fixed Charge ($/mo)	Demand Charge Max $/kW	Variable Price ($/kWh) Min	Med	75th	95th	Max	SD	r
Midwest	Flat	13.98	0.00	0.17	0.18	0.21	0.21	0.21	0.01	0.07
	RTP	16.23	0.15	0.14	0.17	0.18	0.20	0.27	0.01	0.20
Southwest	Flat	17.56	0.00	0.13	0.13	0.13	0.13	0.13	0.00	0.00
	TOU	15.55	0.00	0.04	0.12	0.12	0.25	0.25	0.05	0.13
	TOU+Demand	15.55	8.40	0.09	0.09	0.09	0.14	0.14	0.02	0.17
Northeast	Flat	15.26	0.00	0.19	0.19	0.19	0.19	0.19	0.00	0.00
	Event	15.26	0.00	0.18	0.18	0.18	0.18	0.73	0.05	0.11
	TOU	20.34	0.00	0.13	0.13	0.13	0.29	0.29	0.07	0.14
	TOU+Event	20.34	0.00	0.13	0.13	0.13	0.28	0.73	0.09	0.16
Great Plains	Flat	13.00	0.00	0.05	0.08	0.09	0.09	0.09	0.01	0.08
	TOU	13.00	0.00	0.05	0.05	0.07	0.09	0.22	0.04	0.28
	Event	13.00	0.00	0.05	0.05	0.07	0.10	0.48	0.05	0.47

Note: Summary statistics of the rates used in the analysis. The fixed charge is in $ per month. In order, the subheadings under variable price stand for minimum, median, 75th percentile, 95th percentile, maximum, standard deviation, and the Pearson correlation coefficient of correlation between the hourly $/kWh rates and estimated hourly social marginal costs.

Difference in normalized south-facing PV bill savings for time-based rates compared to flat rates

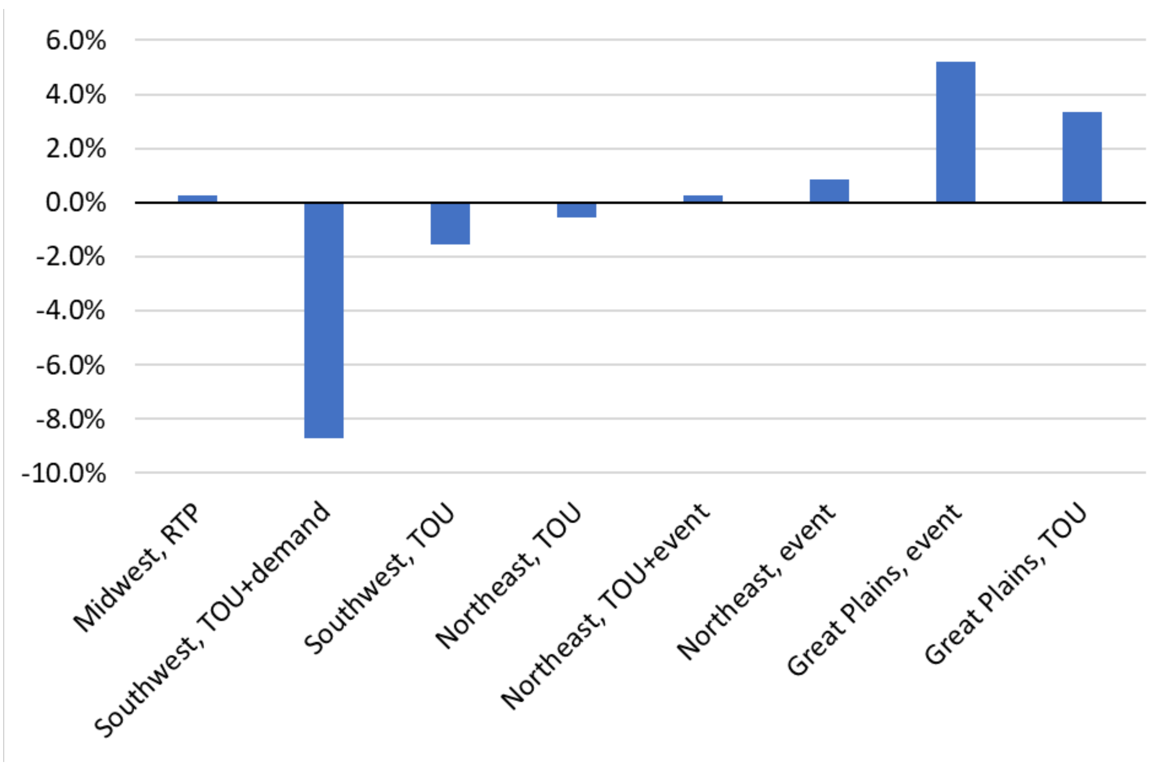
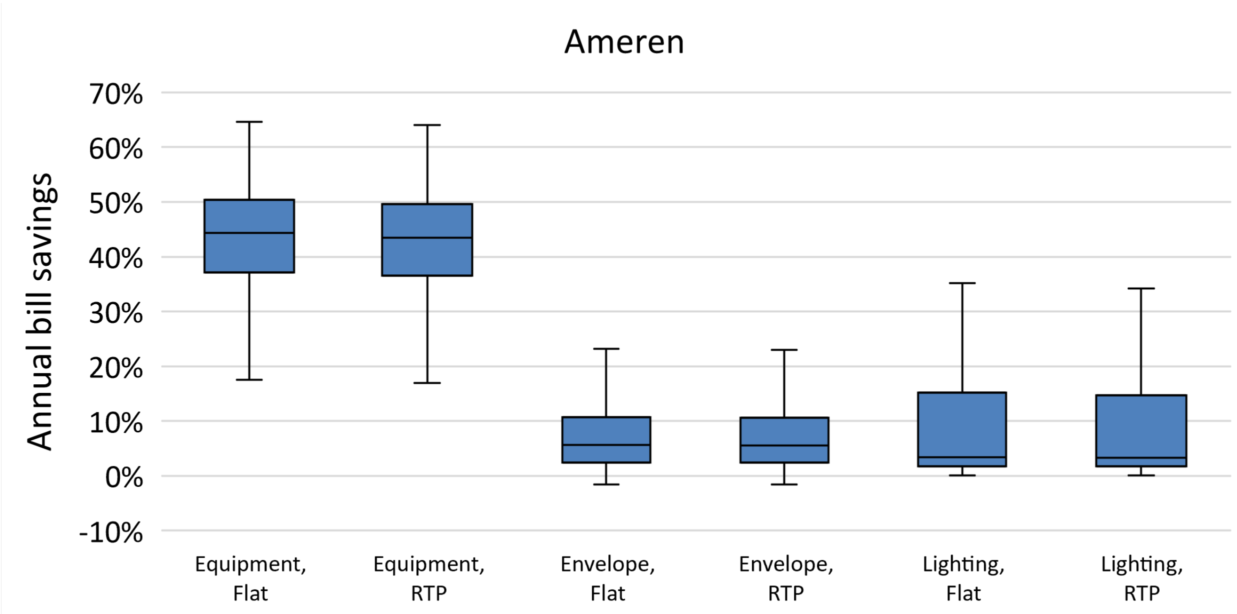


Figure E-1. Difference in south-facing PV normalized bill savings for time-based rates compared to flat rates

Distribution of bill savings by utility and rate-upgrade



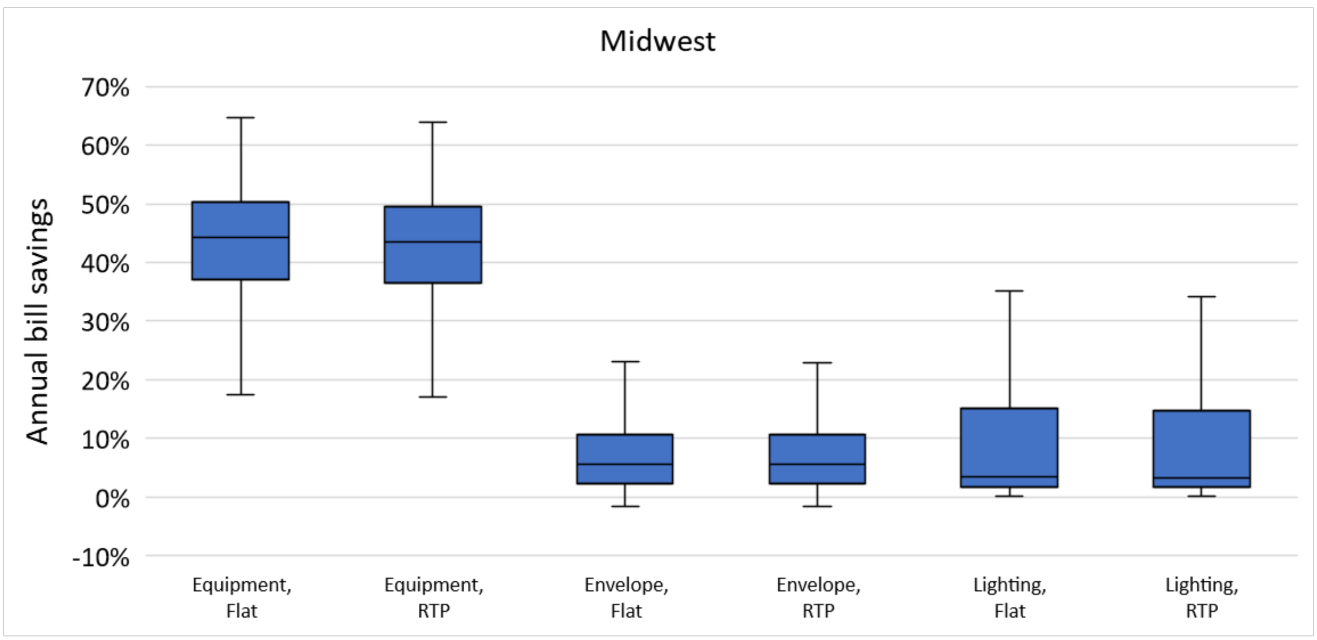


Figure E-2. Distribution of bill savings for Midwest Utility

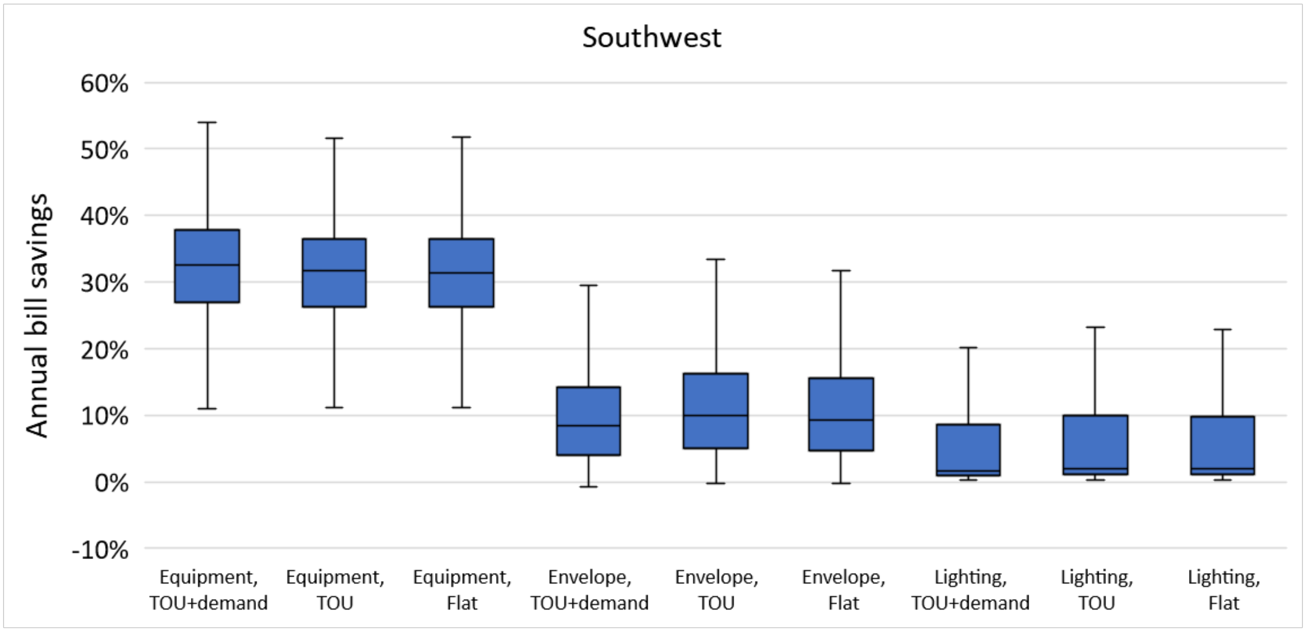


Figure E-3. Distribution of bill savings for Southwest

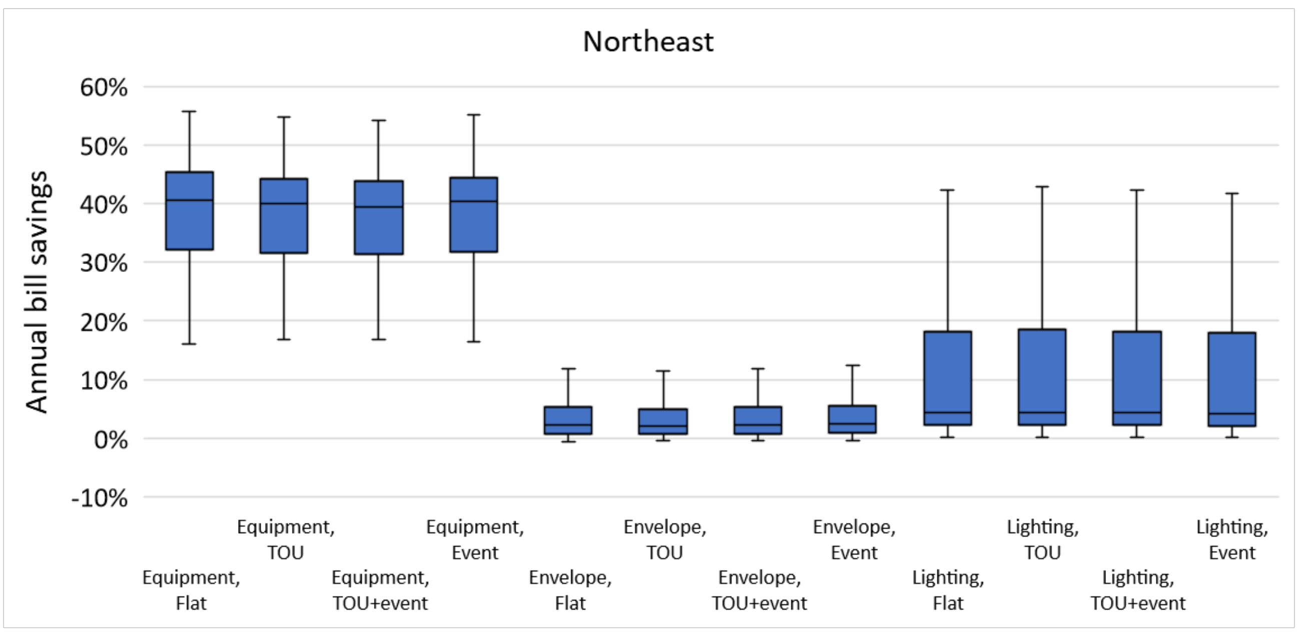


Figure E-4. Distribution of bill savings for Northeast Utility

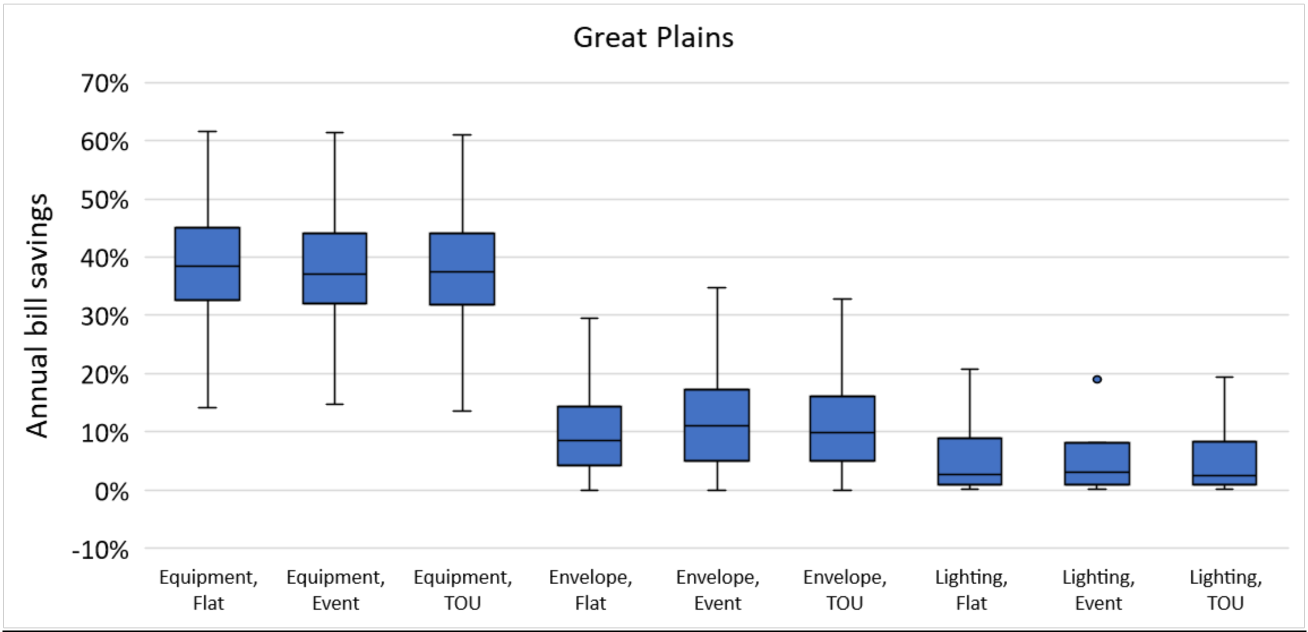


Figure E-5. Distribution of bill savings for Great Plains Utility

<u>Difference in PV bill savings for time-based rates compared to flat rates by orientation</u>

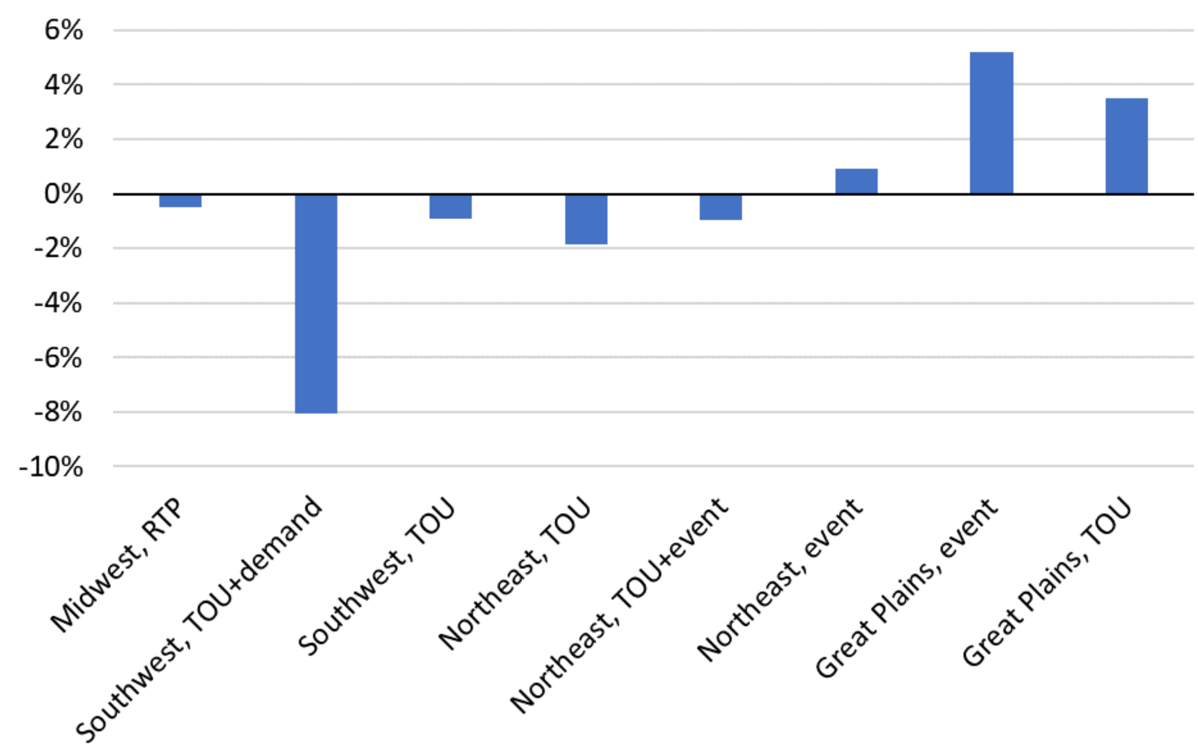


Figure E-6. Difference in south-facing PV bill savings for time-based rates compared to flat rates

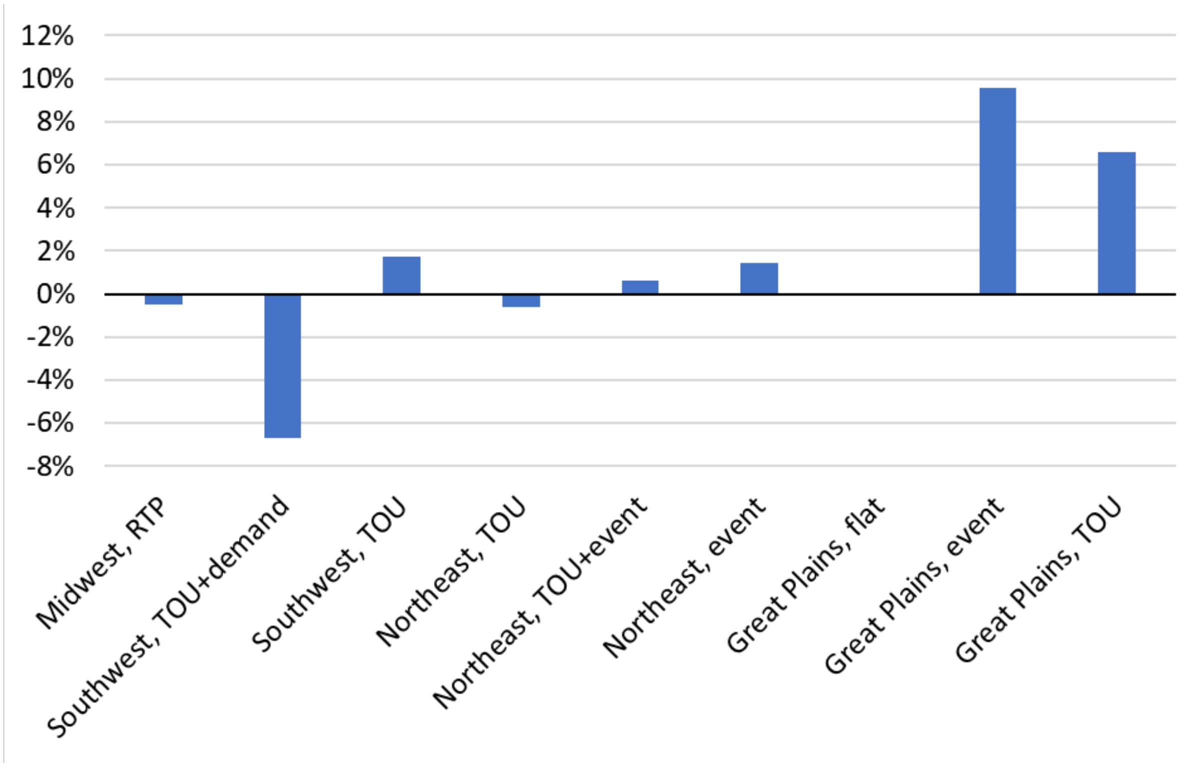


Figure E-7. Difference in west-facing PV bill savings for time-based rates compared to flat rates

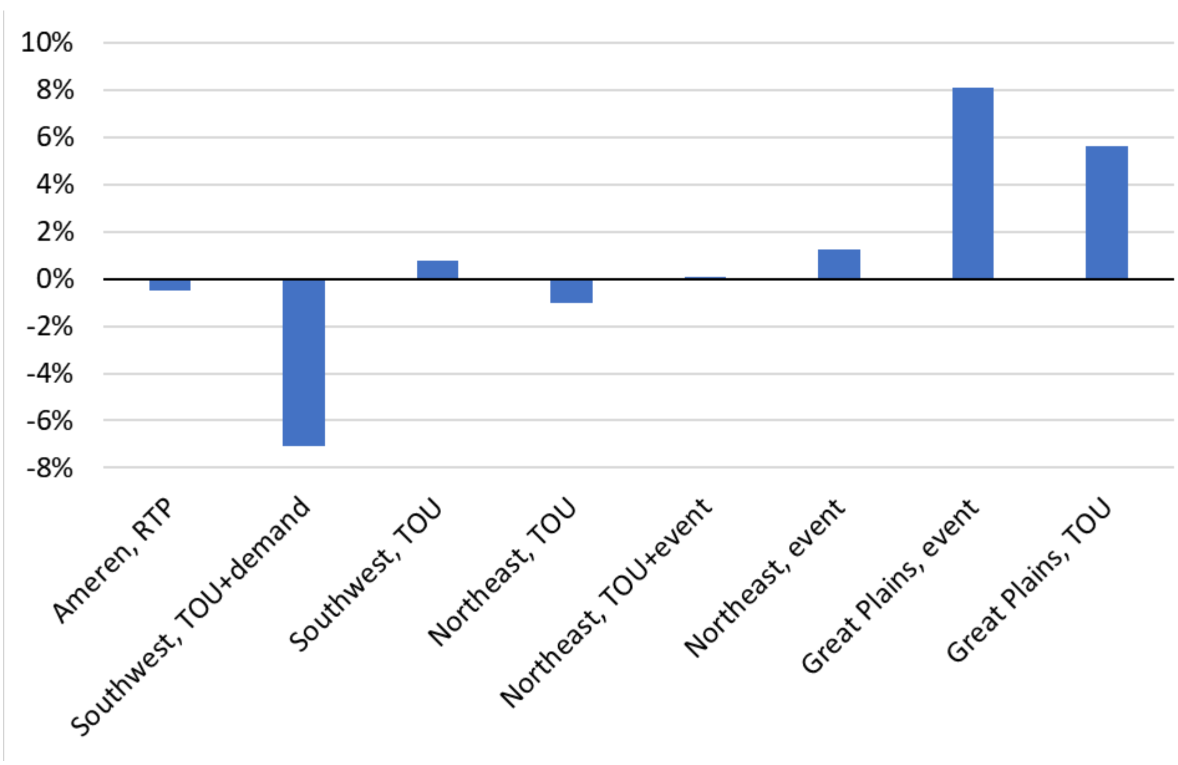


Figure E-8. Difference in southwest-facing PV bill savings for time-based rates compared to flat rates

Average energy savings by rate for PV systems by orientation

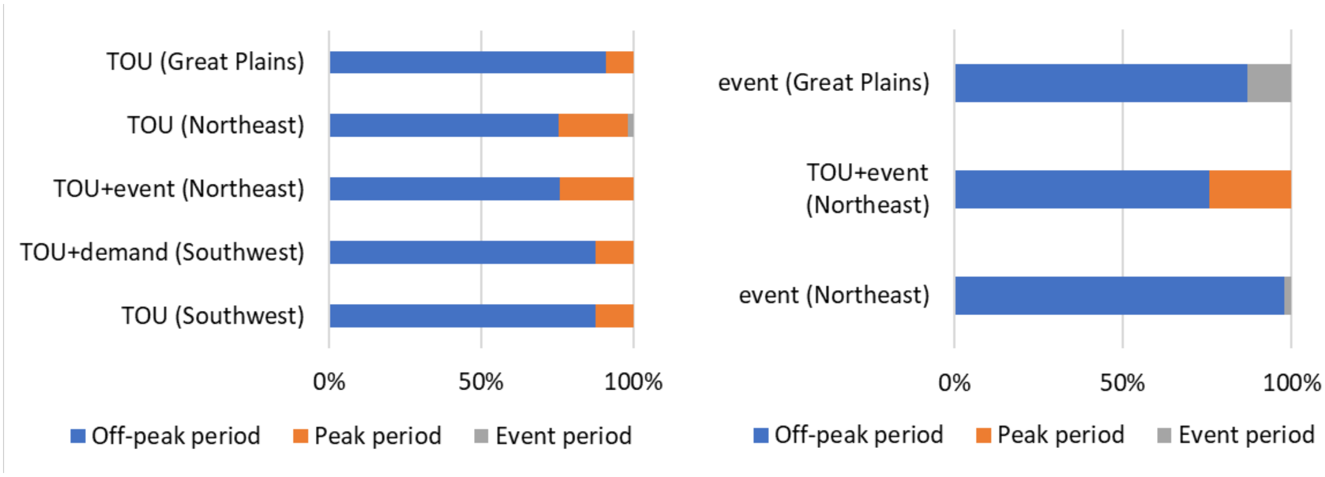


Figure E-9. Average energy savings by rate for south-facing PV systems

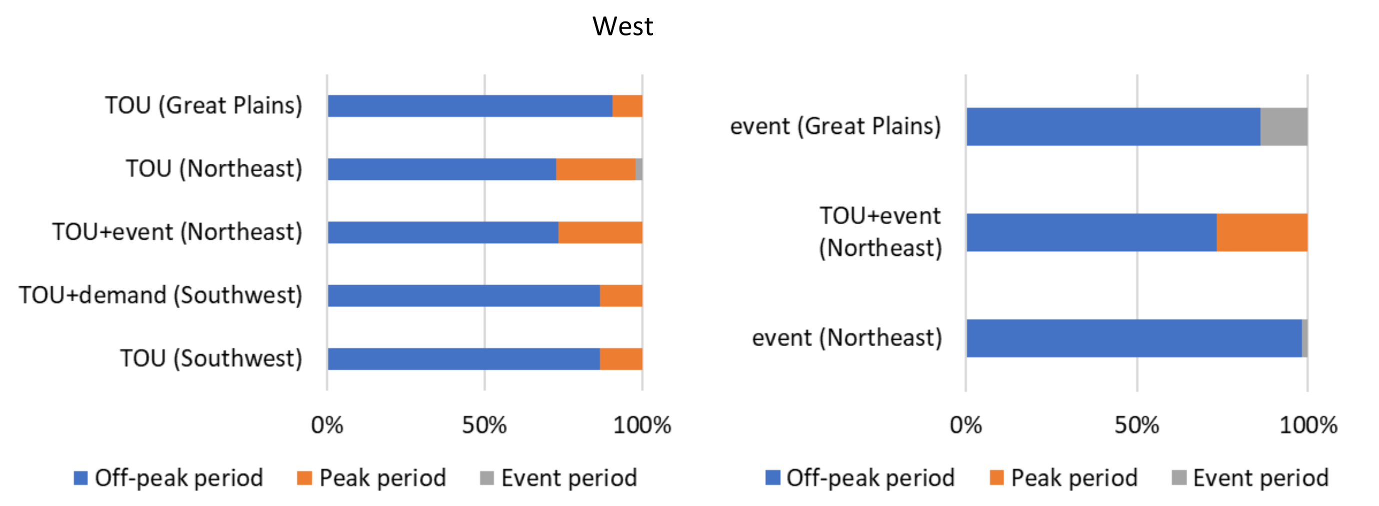


Figure E-10. Average energy savings by rate for west-facing PV systems

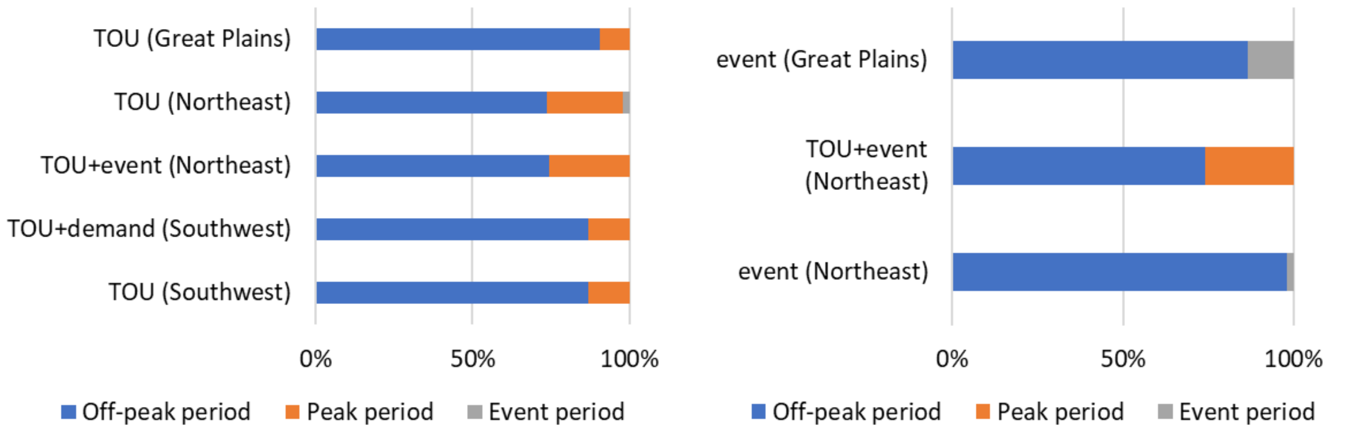


Figure E-11. Average energy savings by rate for southwest-facing PV systems

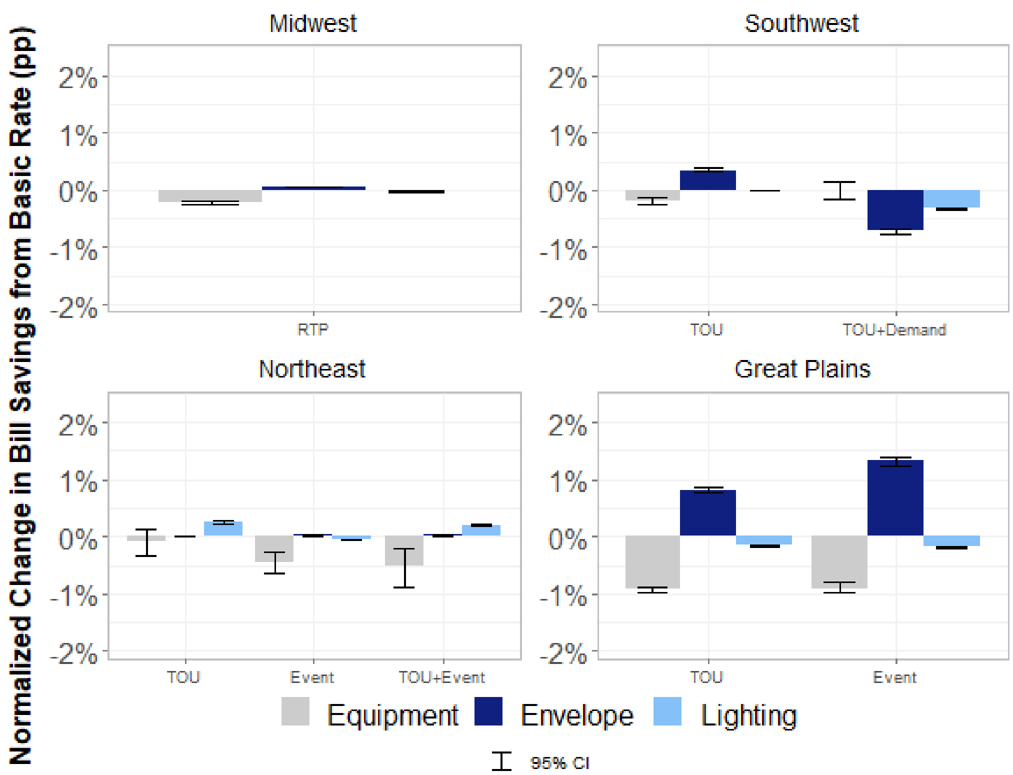


Figure E-12. Median percentage point difference in normalized EE bill savings for time-based rates compared to flat rates with 95% confidence intervals

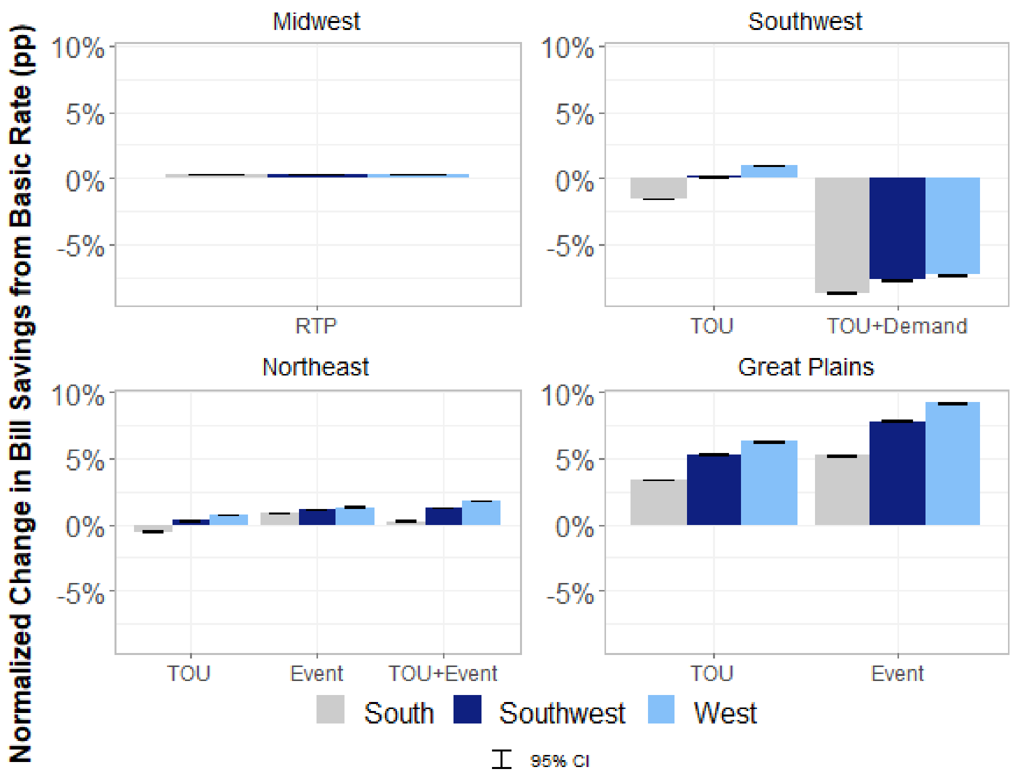


Figure E-13. Median percentage point difference in normalized PV bill savings for time-based rates compared to flat rates with 95% confidence intervals

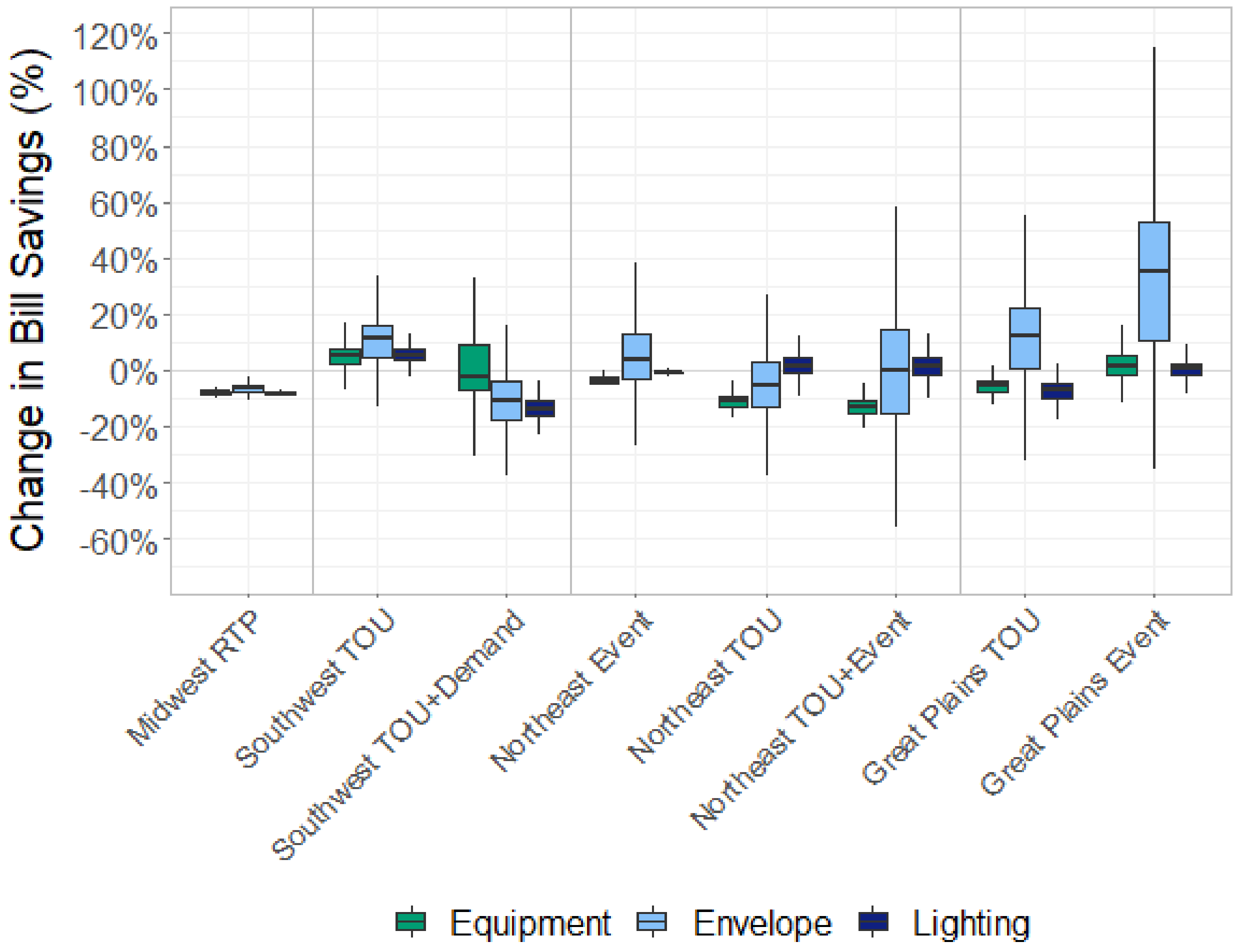


Figure E-14. Box-and-whiskers plot of percentage changes in EE bill savings for time-based rates compared to flat rates

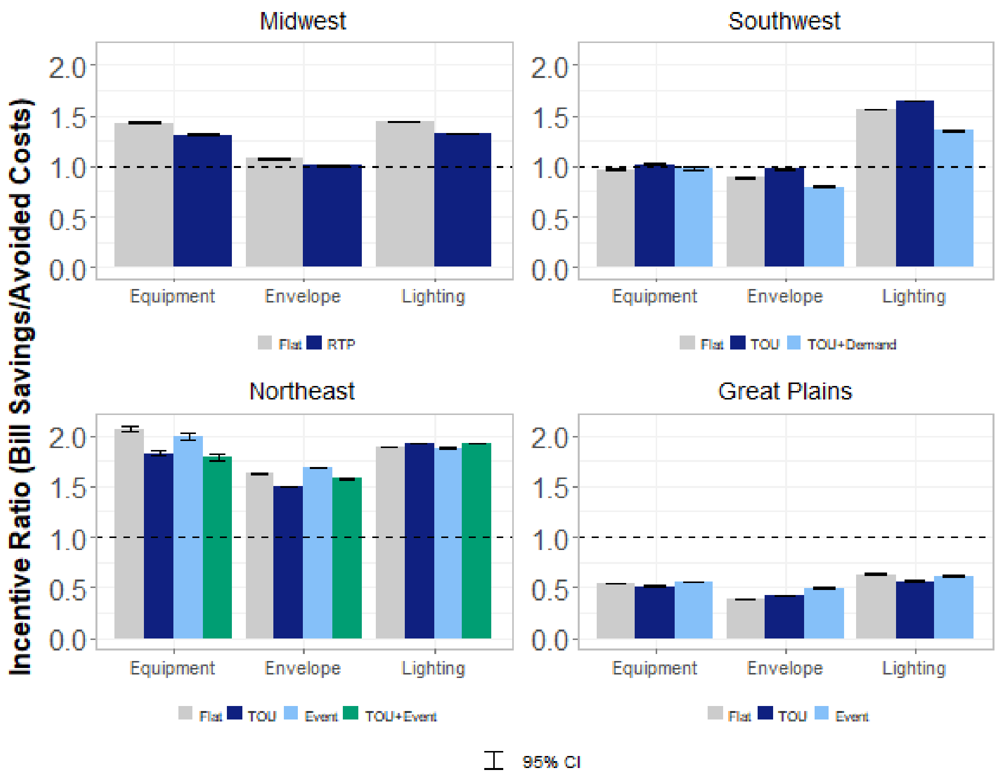


Figure E-15. Median incentive ratio by utility, rate, and EE upgrade package

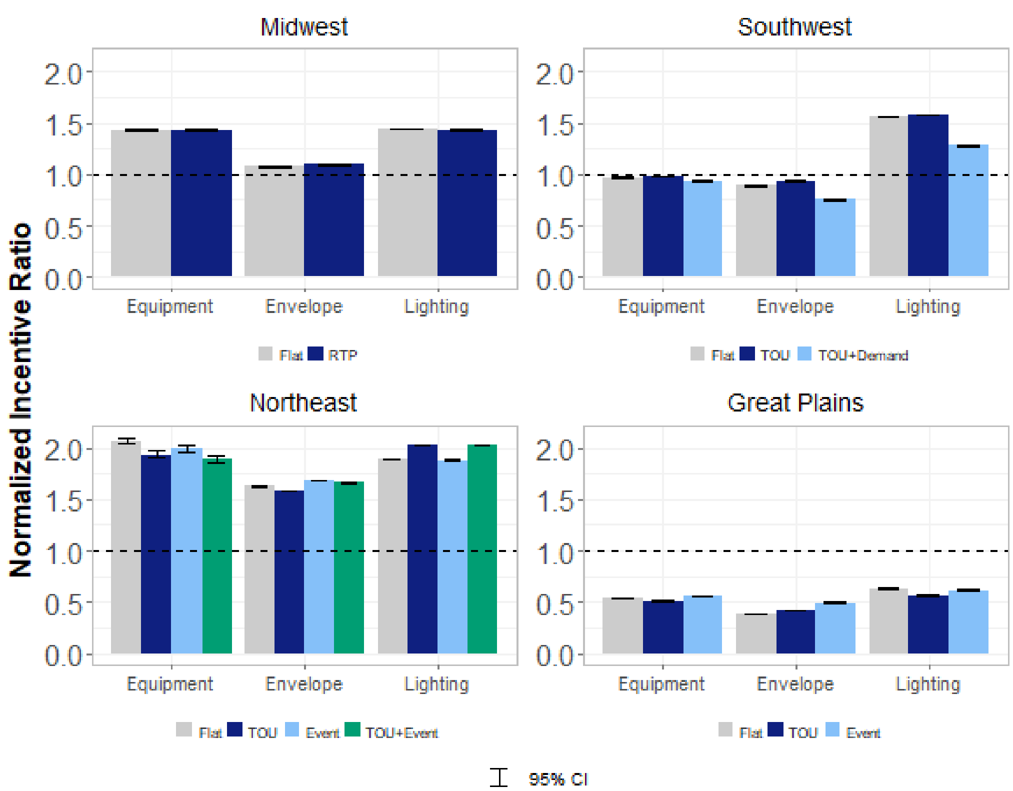


Figure E-16. Normalized median incentive ratio by utility, rate, and EE upgrade package

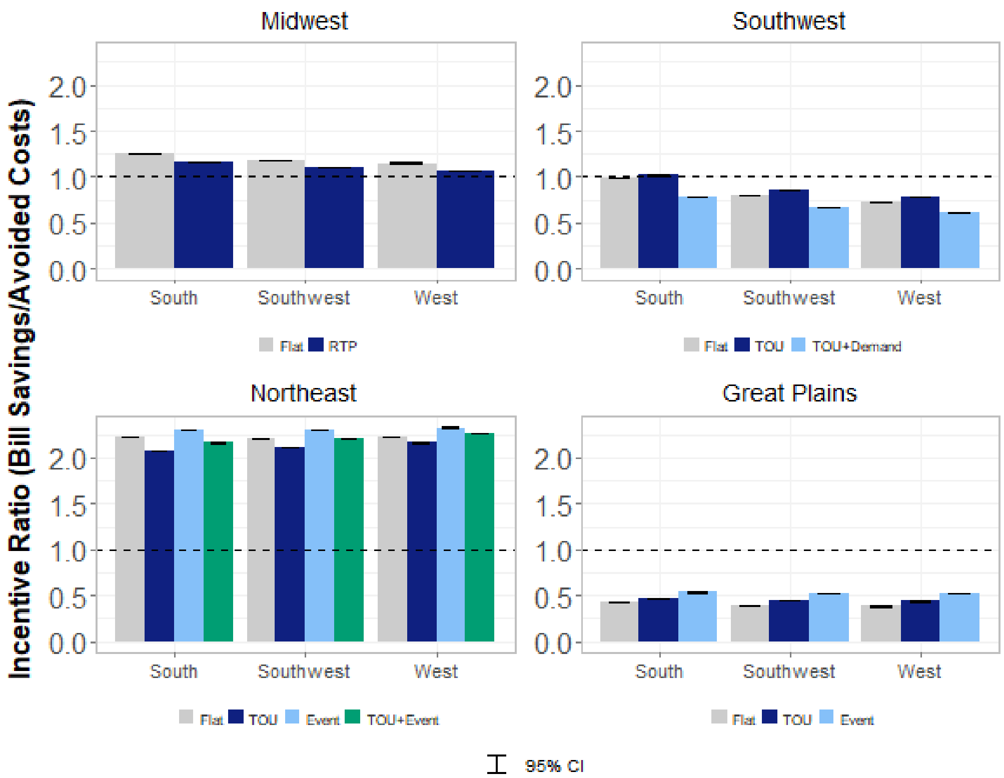


Figure E-17. Median incentive ratio by utility, rate, and distributed PV orientation

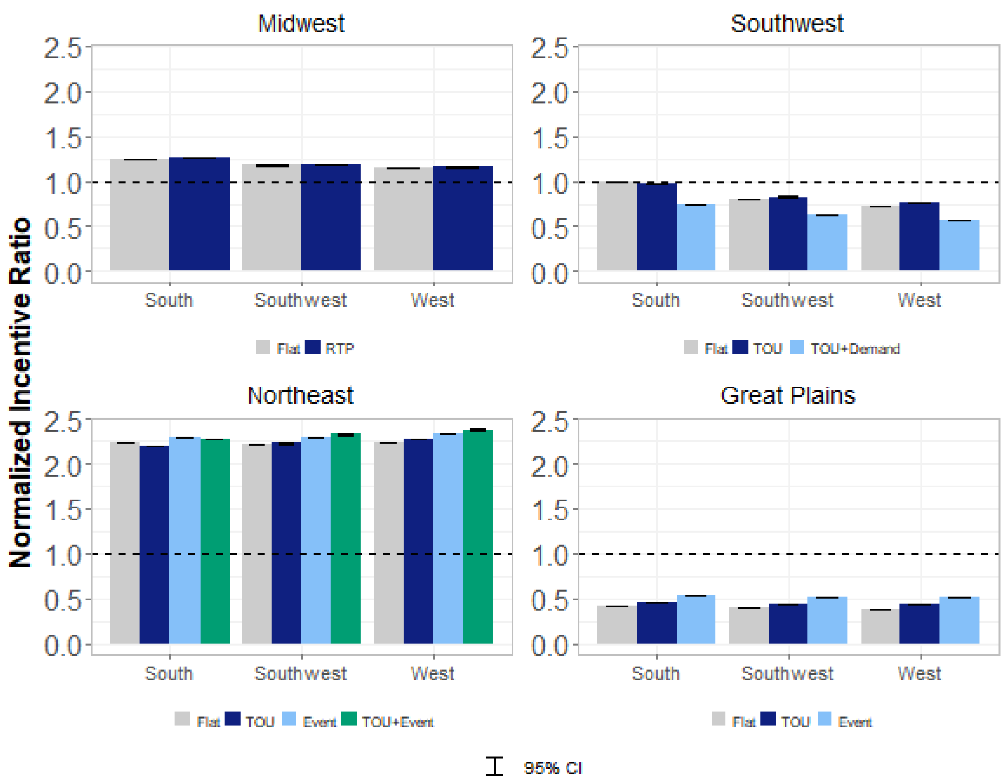


Figure E-18. Normalized median incentive ratio by utility, rate, and distributed PV orientation