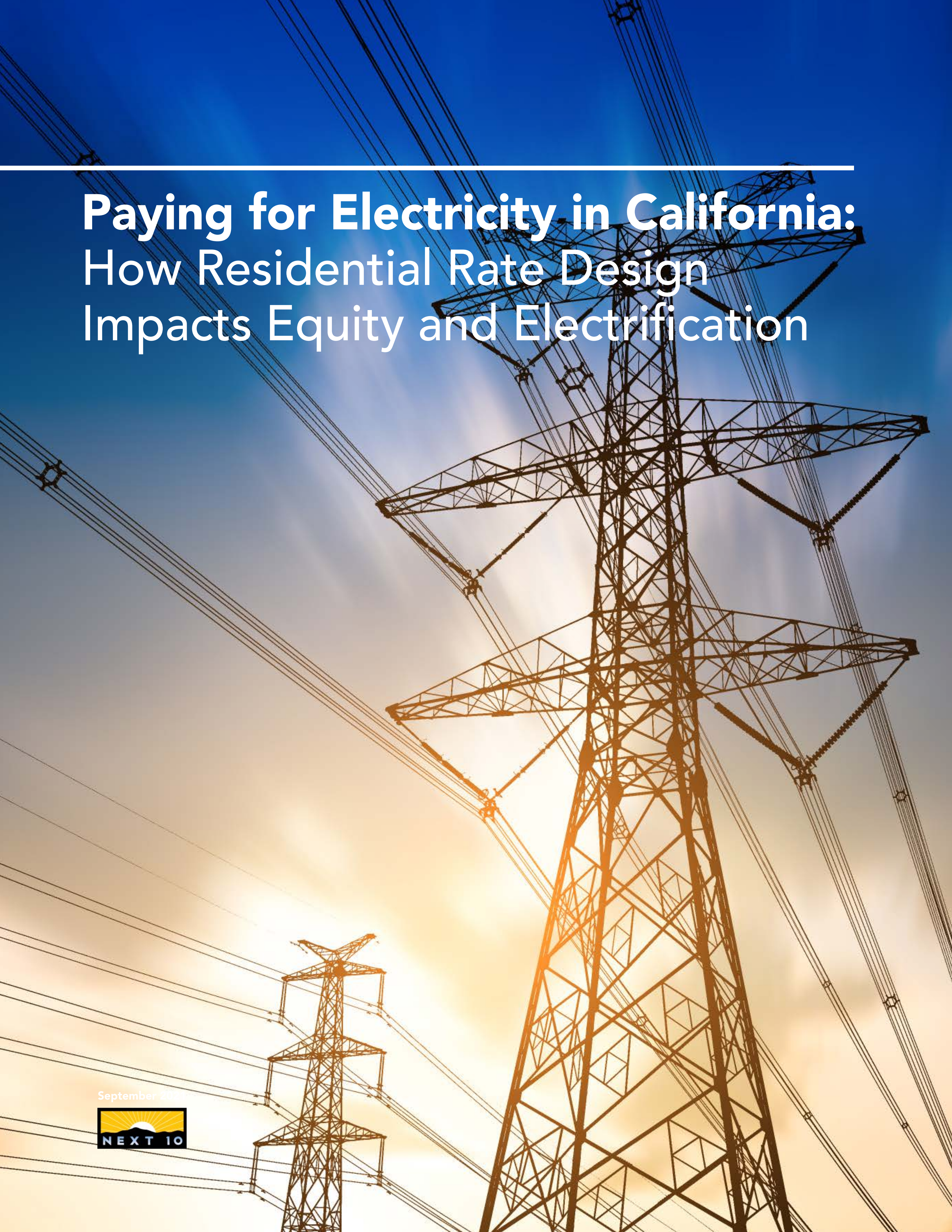

Paying for Electricity in California:
How Residential Rate Design Impacts Equity and Electrification

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NEXT 10

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The Appendix can be found at
https://www.next10.org/electricity-rates-2

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A PROJECT OF

Table of Contents

EXECUTIVE SUMMARY

California has ambitious goals to fight climate change while also ensuring that energy is affordable for all of its residents. Unfortunately, the current structure of residential electricity prices in the state makes achieving these goals much harder. Electric utility rates feature high volumetric (i.e., per kilowatt-hour) prices that are designed to recover many costs beyond the direct incremental cost of providing electricity. These high volumetric prices make electrification less attractive to consumers while simultaneously distributing the burden of paying for electricity in a way that is quite regressive.

In this report, the authors analyze detailed billing data from over 11 million California households served by the state's three large investor-owned utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E)—in order to characterize the implications of the current residential electricity prices for equity and for electrification of vehicles and homes. The authors then discuss potential reforms that could simultaneously improve equity while fostering decarbonization by removing barriers to electrification.

This report builds on a prior companion report that established key facts about retail electricity pricing in California.[1] First, the initial study showed that IOU customers face prices that are two to three times higher than social marginal cost (SMC), which is defined as the going-forward cost to the utility of providing additional electricity to an existing customer, inclusive of pollution costs. Second, the initial report also found that the reason that retail prices are so far above the efficient SMC benchmark is that retail prices are used to recover non-incremental costs of electricity supply along with other programs that have been integrated into bills. This method of cost recovery has generated a large, and rapidly growing, gap between retail electricity prices and social marginal costs. The report authors refer to this gap as the effective "electricity tax."

This report explores the consequences of this effective electricity tax on equity and efficiency and ultimately finds that reforms could better align electricity rates with the state's climate and clean energy goals. Using the detailed billing data, the residual cost burden for each customer—defined as the difference between the amount the customer pays on their bill and the incremental cost to the utility of providing that household with power—is calculated under the current rate system. The distribution of those residual cost burdens across the income distribution is then characterized.

Customers do not see their bill broken into "incremental costs" and "residual cost burden," so the drivers of escalating retail prices are opaque to the typical customer. A primary goal of this analysis is to bring to light essential facts about the current system—who is paying for California's electricity system today? and how is that determined by specific features of current rates?—in order to better inform public discussion.

Household & Equity Impacts: This report offers a first-of-its-kind analysis for California that demonstrates how residual cost increases for customer electricity bills are impacting households and how that impact varies across households with different abilities to pay. The analysis presented in this report finds that:

- Overall, customers across the three IOU service territories contribute $678 per year on average toward the residual cost burden. For PG&E and SDG&E customers, residual cost burdens are more than two-thirds of their total bills, whereas SCE customers pay slightly more than half of their bills towards residual costs. As a result, how California chooses to recover these costs is the primary driver of electricity costs.
- Residual cost burdens vary widely across households. As of 2019, a quarter of households were contributing less than $220 per year, while the quarter of households with the highest usage contributed more than $850 per year.
- California's current electricity pricing regime assigns a greater share of residual costs to higher-income households, but lower-income households pay much more as a fraction of their annual income on average, so much so that the effective electricity tax is more regressive than the state sales tax. Figure ES.1 summarizes these data for 2019: it shows the estimated average residual cost burden by income category for each household (in solid lines, which rise with income), as well what fraction of average income this represents (in dashed lines, which decline with income).[2]

1 Borenstein, Severin, Meredith Fowlie, and James Sallee. *Designing Electricity Rates for An Equitable Energy Transition.* Next 10 and the Energy Institute, February 23, 2021. Available at: https://www.next10.org/publications/electricity-rates.

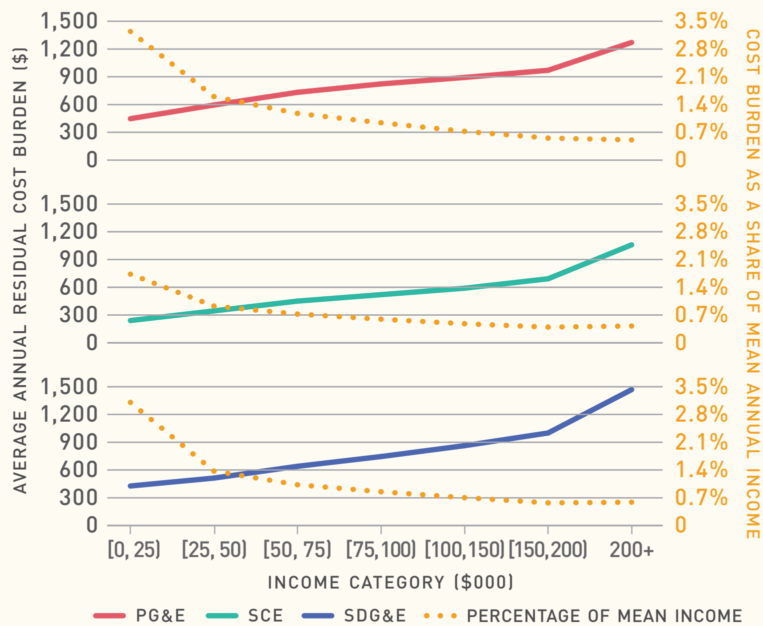
2 This report focuses primarily on 2019 data, because they are pre-pandemic and the most recent available when data were requested from the utilities. But it is clear that the residual cost burden has continued to expand since 2019.

- Net metering for rooftop solar makes the effective electricity tax substantially more regressive. This is because wealthier households are much more likely to have rooftop solar. The effect is strongest in SDG&E, where rooftop solar in 2019 already provided over 20 percent of residential electricity under net metering, thus offsetting a majority of the cross-subsidy created by the California Alternative Rates for Energy (CARE) program.

Impacts on Decarbonization Efforts: The state's strategy for decarbonization includes plans for widespread electrification of buildings and rapid electrification of personal transportation. Relying entirely on the effective electricity tax to recover residual costs, however, implies that customers considering electrification face much higher operating costs if they electrify than they would if prices were set equal to social marginal cost. The authors refer to this increase in operating costs as the "electrification cost premium." Related to this issue, this analysis finds that:

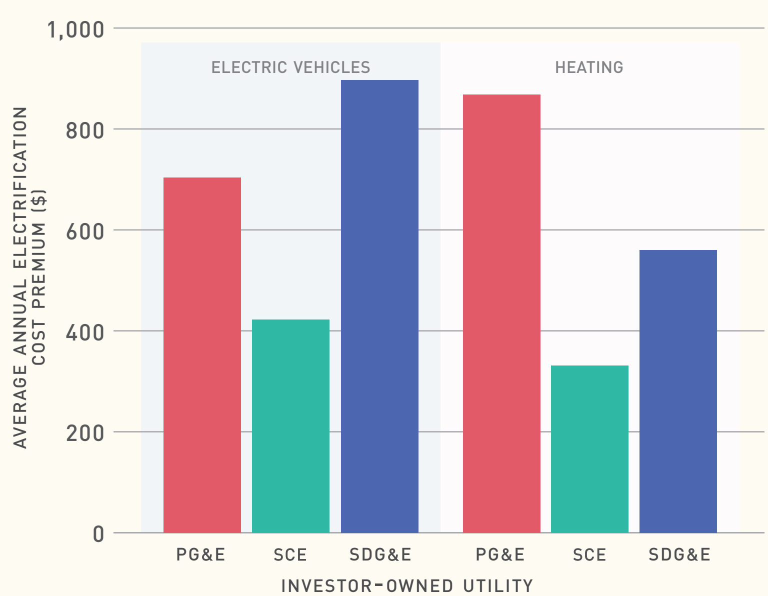
- For California households considering purchasing an electric vehicle (EV), the effective electricity tax raises the annual operating cost of an EV by around $600 per year on average. Recent research suggests that this could be reducing EV adoption by somewhere between 13 and 33 percent. Figure ES.2 shows the average annual electrification cost premium for EVs across the utilities. The premium is close to $900 for the average SDG&E customer.
- For households considering electric heating in lieu of natural gas, the effective electricity tax raises the annual cost of doing so by around $600 per year. Recent research suggests that eliminating this tax could increase the fraction of new homes that are built with electric heating by around one-

FIGURE ES 1 **Annual Residual Cost Burden by IOU (2019)**



Note: Solid lines show average annual residual cost burden (bill amount above SMC) by income category. Dashed lines divide the residual cost burden by average income in the category.

FIGURE ES 2 **Average Annual Electrification Cost Premium by IOU for Electric Vehicles and Home Heating (2019)**



Note: For electric vehicles and electric heat pump space heating in each utility territory, this graph shows the difference in average annual operating cost comparing current prices to price set equal to SMC. See text for details.

third. Figure ES.2 shows how the electrification cost premium for home heating varies across the utilities, with the highest annual burdens, around $850 on average, in PG&E.

Fortunately, there are ways that residential electricity rates could be reformed in order to foster electrification (by lowering volumetric prices), while simultaneously improving equity outcomes. Some of these possible reforms were discussed in the previous related report,[3] but with the detailed billing data available for this report, the authors are now able to examine their impacts much more closely. They find that:

- Moving some costs that contribute to the residual cost burden onto the state budget, to be funded by increases in the sales or income tax, would increase equity and improve efficiency because it would reduce the effective electricity tax. A variety of costs that might be moved are discussed, including public purpose programs, legacy costs and costs related to wildfires.
- Introduction of income-based fixed charges would similarly increase equity and efficiency at the same time. As an example, the authors consider a system of income-based fixed charges that would mimic the progressivity of the state's sales tax, showing the rates needed and the distribution of bill changes it would induce.
- Minimum bills, which have been suggested as a potential source of funds to cover the residual cost burden, would be both ineffective and highly inequitable. The report authors conclude that minimal bills are more regressive than even the current rate structure, as more than half of the added revenues from a minimum bill would be paid by households with below-median income. In addition, minimum bill levels that have commonly been discussed in the current debate, such as $30 per month, would make an extremely small contribution to covering the residual cost burden.

Some of the challenges with rate reforms are discussed in this report. The authors also note that, even where it is possible to pursue rate reforms that are equitable *on average* across income categories, their analysis of the billing data makes clear that there would be a wide distribution of resulting winners and losers—which could make it more difficult to reach political consensus on reform.

In this report, the authors take as given the amount of revenue that utilities need to recover. Another important policy direction is to identify and reduce any costs due to inefficiency or unnecessary expenditures, but that is not pursued in this report. Also, this report focuses exclusively on residential electricity rates. Commercial and industrial electricity rates are also used to cover costs above SMC, raising many of the same issues around electrification, as well as different concerns over equity and business climate in California.

Given this context and these complexities, this report is first and foremost aimed at providing useful facts and outlining possible paths forward, guided by the twin objectives of fostering decarbonization and improving equity. All possible reforms create some manner of trade off, and as such should be debated in the broader policy context in the state.

3 Borenstein, Severin, Meredith Fowlie, and James Sallee. *Designing Electricity Rates for An Equitable Energy Transition.* Next 10 and the Energy Institute, February 23, 2021. Available at: https://www.next10.org/publications/electricity-rates.

INTRODUCTION

A promising path to deep decarbonization of the economy runs through the electricity sector. This vision calls for an accelerated decarbonization of electricity generation coupled with the widespread electrification of transportation, buildings, and some industrial applications. Attaining this vision, however, will require major investments in the power sector.

Capital investments are needed both to accelerate the deployment of renewable electricity generation and to install the transmission and distribution system infrastructure that renewable energy integration requires. Moreover, substantial investments will be needed to adapt the power system to a changing climate. Ensuring grid reliability and resilience in the face of more extreme and more frequent weather events will require additional capital spending—over and above the investments required to decarbonize the electricity sector.

Who will pay for all this? In the United States, it has been standard practice for utility regulators to use retail energy prices as a vehicle for recovering capital and operating costs. In California and many other states, the costs of implementing related government policies, such as subsidizing energy efficiency investments, technology research and development, rooftop solar installations, and bill reductions for low-income customers have also been recovered via higher electricity prices.

Setting the volumetric price for electricity well above the incremental cost of electricity supply amounts to taxing grid electricity consumption. This effective "electricity tax" is both regressive and economically inefficient. It is a regressive way to raise revenues because lower-income households spend a relatively large share of their income on electricity. Against a backdrop of growing income inequality and social stratification, and amidst escalating concerns about energy poverty and affordability, increasing retail electricity prices to keep up with rising power sector fixed costs and related policy costs will only exacerbate these inequalities.

An electricity tax is economically inefficient because burdening electricity prices with costs that are not going-forward incremental expenses of supplying electricity discourages efficient substitution from natural gas and gasoline other energy sources towards electricity. As such, high electricity prices act as a deterrent to electrification of transportation and buildings.

Fortunately, policymakers have alternatives when it comes to recovering costs associated with climate mitigation and adaptation, as well as other non-incremental costs. Alternative approaches to revenue recovery can be used to pay for grid investments and related policies in ways that are more equitable and less obstructive to investments in electrification.

This study builds on a prior report, *Designing Electricity Rates for An Equitable Energy Transition*, which described the current system of cost recovery among the California's three large investor-owned utilities (IOUs) and proposed some alternatives.[4] That report documented a few key facts that bear repeating in order to set the stage for the current analysis.

First, the volumetric price California residential customers pay for electricity—the component that changes with the quantity of consumption—is far above the social marginal cost (SMC)—the cost of producing and delivering another kilowatt-hour (kWh) of energy to an existing customer, including the social cost from pollution. In 2019, residential prices for the three large IOUs were two to three times higher than SMC. This gap continues to widen over time. It stems from the fact that California regulators have chosen to have IOUs recover nearly all costs—variable, fixed, and related policy costs—through high volumetric prices.

Second, recovering system and policy costs via electricity rates that are far above social marginal cost amounts to an effective electricity tax. Like any other tax, the effective electricity tax requires that customers pay a price that exceeds the incremental cost. The tax revenue is used to cover other costs, in this case system costs for the grid and the cost of related policy goals, such as wildfire mitigation, compensation for past victims of wildfires, making early investments in renewable technologies, plus subsidizing energy-efficiency programs, rooftop solar, and low-income customers. The previous report, using survey data, suggested that this effective electricity tax is a particularly regressive way to cover these costs—more regressive than a sales tax, and far more regressive than an income tax.

Third, the report proposed some alternative ways to recover system and policy costs. One possibility is to pay for some costs out of general state revenue. Another possibility is to institute a system of monthly fixed charges that depend on a household's income. Under the latter approach, the utility recovers the same amount of revenue as before, but it does so by significantly lowering the volumetric price (per kilowatt-hour) and making up the needed revenue via monthly fixed charges. Lowering volumetric prices towards the SMC improves efficiency and makes it more attractive to electrify space heating, water heating, transportation, and other resi-

4 ibid.

dential energy services. A fixed charge schedule that increases with income also addresses affordability concerns by making cost recovery less regressive.

This report extends this prior work in three important ways:

First, the authors use household-level billing data from the state's IOUs to characterize in detail the distributional implications of recovering costs in excess of SMC under the current regime. Section 2 documents the variation in the size of the effective electricity tax burden across households of similar income as well as across the income distribution. The authors show the extent to which the lowest-income households spend larger shares of their income—over three percent on average—on this tax. This analysis paints a more complete picture of how escalating power sector costs are being allocated across California households.

Second, the authors assess the implications of California's high electricity prices for electrification goals in the residential sector, focusing in particular on electric cars and electric space heating. Section 3 begins by quantifying the size of the "electrification cost premium"—the increase in the cost of operating an electric vehicle or residential space heating—under the existing electricity sector cost recovery regime. To assess the likely impacts of these higher operating costs on incentives to electrify, the authors use estimates from recent empirical studies of electric vehicle adoption and residential building electrification. They find that high prices have substantially reduced the pace of electrification in California; estimated adoption rates under efficient pricing would increase by up to one-third.

Third, report authors use the household-level billing data to describe in detail how alternative financing strategies would shift the burden of cost recovery. Section 4 considers a number of alternatives, including the income-based fixed charge idea advanced in the first report, and a minimum bill provision which some stakeholders have actively promoted. Again, the analysis shows not only the average gains and losses among households of different income levels, but also how these gains and losses vary among households with similar incomes who differ in their energy usage.

How state regulators choose to cover the costs incurred in California's electricity sector, including costs associated with the clean energy transition and climate change adaptation, will determine how efficiently the state is able to make the transition and who ultimately pays the price. This report aims to inform an urgent policy conversation around the need for retail energy price reform, elucidating how cost burdens are shared under the current regime, and arguing that a growing cost burden should be reallocated in a way that achieves both efficiency gains and equity improvements.

WHO PAYS AN ELECTRICITY CONSUMPTION TAX?

With access to household-level billing data from approximately 11 million California households, the report authors are able to assess how retail electricity rate designs impact ratepayers across the income spectrum in detail. In what follows, the data used in this analysis is introduced. The authors explain how they combine billing data with census data and the California Residential Appliance Saturation Survey (RASS)[5] to estimate household-level income for utility customers. While these income estimates are imperfect, this approach offers a substantive improvement over the more standard practice which uses group-level averages. This section concludes with a detailed characterization of how the effective electricity tax burden is distributed along the income dimension.

5 California Energy Commission. *2019 Residential Appliance Saturation Study.* August 4, 2021. Available at: https://www.energy.ca.gov/data-reports/surveys/2019-residential-appliance-saturation-study

2.1 Household-level tax burden

To study how the effective electricity tax burden is distributed across households, the report authors obtained monthly billing data on all residential customers from PG&E, SCE and SDG&E, over 11 million California households, between 2016 and 2019.[6] These data contain monthly information for each household, including monthly electricity consumption, monthly electricity bill amounts, the marginal electricity price, and information about household participation in CARE for low-income households and net energy metering (NEM) for solar PV owners. The dataset also specifies the type of tariff each household has, as well as detailed geographic information (census block group and climate zone). Taken together, the data set includes over 500 million customer-month observations.

The authors compare households' annual electricity expenditures to the social marginal cost of the grid electricity they consume.[7] They refer to the difference between the amount a customer was billed and the product of grid electricity consumption and the corresponding SMC as the "residual cost burden." The aggregate of the residual cost burden for all of a utility's residential customers is referred to as the residual revenue requirement.[8]

The authors then calculate the annual residual cost burden for each household included in the data analyzed for each year by summing bills and consumption over twelve months, as illustrated in the following equation:

$$(1)\ \text{Residual cost burden}_{iy} = \sum_{m=1}^{12} \text{Elec bill}_{imy} - SMC_{iy} \sum_{m=1}^{12} Q_{imy},$$

Where Q_{imy} denotes the net electricity consumed from the grid by household i in month m and year y; Elec Bill_{imy} is the total amount billed (in dollars) to household i in month m and year y; and SMC_{iy} is the average social marginal cost for household i's utility in year y.[9]

Figure 1 summarizes the distribution of these household-level contributions, by utility, in 2019. The graph shows two key facts. First, residual cost burdens are large. The average annual residual cost burden is $809 for PG&E customers, $512 for SCE customers, and $786 for SDG&E customers. In 2019, residual cost burdens accounted for about half of SCE customer bills and nearly two-thirds of PG&E and SDG&E bills. As a consequence, the way that these costs are recovered is the main driver of electricity costs for California households. These residual cost burdens are growing as the costs of climate change mitigation and wildfire adaptation escalate. PG&E, for example, saw an increase in its total residential revenue requirement in 2022, which reflects both changes in SMC and residual cost burdens, of 11 percent as compared to 2019.

Second, Figure 1 illustrates that there are large differences across households in this residual cost burden. Among PG&E customers, for example, a household at the 25th percentile of this distribution contributes $520 per year to residual costs, while a household at the 75th percentile contributes three times more, or $1,580. Many factors contribute to this variation, including differences in electricity consumption levels, climate zones, electricity rates, and solar PV adoption.

6 Though the authors did have data for part or all of 2020 from each of the utilities, at this point they did not use 2020 data due to the pandemic.

7 Because the report authors do not observe hourly consumption, they cannot match consumption profiles to the corresponding utility-specific hourly SMC profiles. Therefore, the utility-specific annual average SMC is used.

8 Commercial and industrial customers also pay prices above SMC and contribute to covering residual costs, but this report focuses on residential customers, so the authors hold constant the contribution from residential customers in aggregate.

9 Though this discussion refers to the "month" of each bill, billing cycles do not correspond to the start and end of calendar months and differ across customers. The researchers use the actual billing cycles for these calculations and split bills at the start and end of each year assuming that average consumption was constant over the days of those bills. For households with solar that are on NEM 2.0 (which started in 2016), Elec bill$_{imy}$ includes the non-by passable charge paid on electricity generated by rooftop solar that is injected into the grid and used to offset subsequent grid-electricity consumption. Because the authors observe only aggregate consumption and aggregate bill over the (approximately monthly) billing cycle, they use the annual average SMC for these calculations. Using this average implies that the actual average SMC of supplying power to each household is the same. This is clearly not the case, but the relationship between household average SMC and other demographics has not been well explored. One exception is the effect of rooftop solar on average SMC of electricity supplied by the grid. Due to the very high solar penetration in California, rooftop systems tend to be exporting when prices and environmental impacts are low—the middle of the day—and importing when they are high. A higher average SMC for rooftop solar households would imply that the actual residual cost burden of solar PV households is lower than assigned and the actual residual cost burden of other households is higher than assigned.

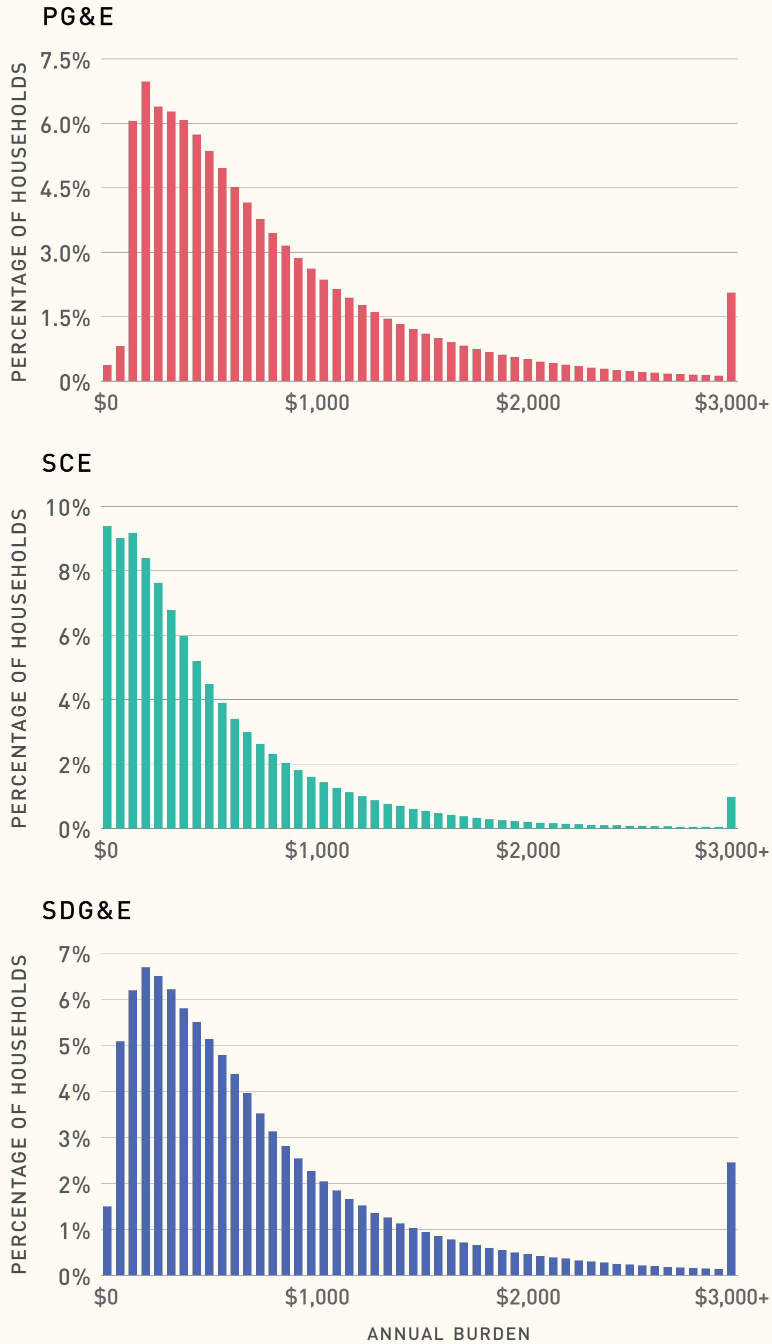
The key implications of this figure are that (a) the current rate system assigns a wide distribution of residual cost burdens, (b) that these burdens are the main driver of customer bills, and (c) as a consequence, alternative methods of residual cost recovery would lead to large changes in these burdens across households. Next, a characterization of how this distribution of burdens relates to income is provided.

2.2 Inferring household income

Having estimated household-specific contributions to utilities' residual revenue requirements, a natural question to ask is: How do these tax burdens vary across more versus less advantaged households? In this section, household-level income is estimated for the residential electricity customers in the data. Annual income is an imperfect measure of households' level of vulnerability, but it is a reasonable point of departure for a distributional analysis of retail electricity pricing.

Household income is not directly observed in the electricity billing data, but detailed information about household location is available. This allowed the researchers to precisely match each household with a census block group (CBG), which on average contains about 570 households. Prior studies have used median income, measured at the CBG level, as an income proxy for of all households in the group. The advantage of that approach is that median CBG income is readily observed in U.S. Census data. The disadvantage is that this ignores significant variation in household incomes within census block groups. Assigning the median (or mean) income to every household within a CBG will substantially understate the dispersion in income.[10, 11]

FIGURE 1 **Annual Residual Cost Burden by IOU (2019)**



Note: These figures summarize utility-specific distributions of annual residual cost burdens borne by residential utility customers in 2019. For each household, the residual cost burden is calculated using Equation (1).

10 Borenstein, Severin. 2012. "The Redistributional Impact of Non-Linear Electricity Pricing." American Economic Journal: Economic Policy, 4 (3), 56-90.

11 Recent work by Cahana et al. (2022) also demonstrates the importance of inferring household-level income when analyzing the distributional impacts of retail electricity rate structures. When they use household-level income, they find that real-time electricity pricing in Spain is slightly regressive relative to a flat price. An analysis that uses zip code averages as a proxy for household-level income reaches the opposite conclusion. (Cahana, Michael, Natalia Fabra, Mar Reguant, and Jingyuan Wang. 2022. "The Distributional Impacts of Real-time Pricing." CEPR Working Paper DP17200.)

TABLE 1 Estimated Share of Households in Each Income Category (2019)

		INCOME CATEGORY ($000 PER YEAR)						
IOU	Total Customers	[0,25)	[25,50)	[50,75)	[75,100)	[100,150)	[150,200)	200+
PG&E	4,690,424	16%	16%	14%	12%	16%	10%	16%
SCE	4,548,790	16%	19%	16%	13%	17%	9%	10%
SDG&E	1,323,612	14%	17%	16%	13%	18%	10%	13%

To improve upon the standard practice of using group medians or means to proxy for household-level income, the research team leveraged two additional data sources. First, using data from the 2019 American Community Survey (ACS) 5-year sample, they estimated the distribution of household income within each census block group.[12] If there were a perfect rank order correlation between electricity consumption and household-level income within each CBG (i.e., the household with the highest income in the CBG has the highest consumption, and so on), the authors could simply sort households within a CBG by gross electricity consumption and assign each a corresponding income by matching their rank to the income distribution for their CBG. However, there are many factors that generate variation in electricity consumption within a CBG. Assuming a perfect and positive rank-order correlation would lead to overstating the progressivity of the current electricity consumption tax. On the other hand, assuming zero correlation, as Burger et al. (2020) do, would lead to understating the progressivity.[13]

To more accurately approximate the within-CBG relationship between income and electricity consumption, the Residential Appliance Saturation Survey (RASS) is leveraged. The 2019 RASS is a stratified random survey of 51,500 California households. Survey data include household-level information about CARE participation, rooftop solar adoption, and a categorical measure of household income. This information is used to empirically estimate the within-CBG relationship between income and electricity consumption for CARE customers and non-CARE customers, respectively. RASS is also used to estimate CARE participation rates by income category. The Appendix includes a detailed explanation of how each household is assigned a position in their CBG income distribution on the basis of their gross electricity consumption and CARE participation status.

Based on the steps described above, Table 1 shows the estimated number of households in the data for each utility and the allocation across the seven income categories used for the analysis.[14]

2.3 How does the residual cost burden vary with income?

With estimates of household-level income in hand, the relationship between household income and electricity consumption can now be investigated. This relationship plays an important role in determining the equity implications of relying on high volumetric retail prices, rather than fixed charges, to recover residual costs. The current 'linear pricing' practice is often rationalized on the grounds that wealthier households consume more electricity and thus will end up contributing relatively more when cost recovery is achieved via a per kWh tax.[15]

Figure 2 summarizes estimated average annual household electricity consumption, measured in kWh, by income category. The solid lines chart average gross consumption values, which are derived by adding estimated rooftop solar generation to the observed net consumption for those households with PV systems.[16]

12 These statistically reliable distributions are based on approximately a 14 percent Census population survey sample over 5 years.

13 Burger, Scott P, Christopher R Knittel, Ignacio J Pérez-Arriaga, Ian Schneider, and Frederik Vom Scheidt. 2020. "The Efficiency and Distributional Effects of Alternative Residential Electricity Rate Designs." The Energy Journal, 41(1).

14 To be included in the dataset for a given year, a household must have bills that cover at least half of the year. Households in the dataset, but with less than full-year coverage are extrapolated to the full year accounting for average seasonal variation.

15 Levinson, Arik, and Emilson Silva. 2022. "The Electric Gini: Income Redistribution through Energy Prices." American Economic Journal: Economic Policy, 14(2): 341–65.

16 As explained in the Appendix, to estimate solar generation, the authors matched a database of residential solar installations from Lawrence Berkeley National Lab to the billing data based on ZIP Code and date of installation. The database includes the system capacity. A solar generation calculator was then used to estimate the average output from the system in each month.

The broken lines chart consumption net of rooftop solar generation. Overall, the authors estimate that rooftop solar production accounts for 13 percent of gross residential consumption for PG&E, 9 percent for SDG&E, and 22 percent for SDG&E.

The most striking feature of Figure 2 is the widening difference between gross and net electricity consumption as household incomes rise. Net electricity consumption rises with income much more slowly than does gross consumption. This is because higher-income households are far more likely to have rooftop solar and to install larger systems. This makes the current effective electricity tax more regressive because, under net metering, households are billed for net consumption.[17]

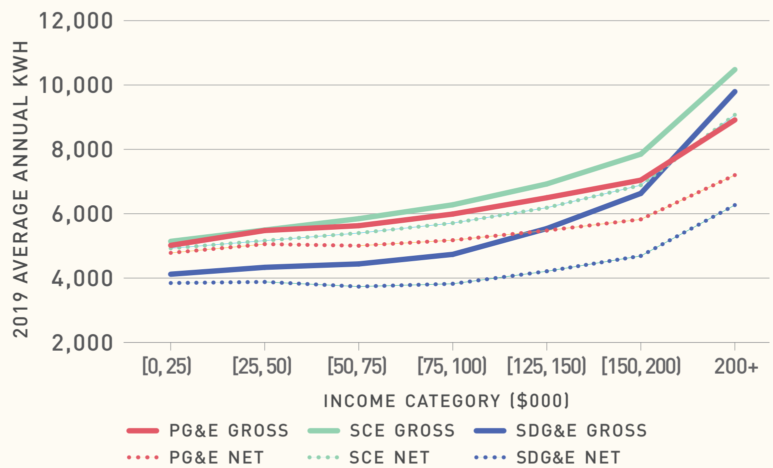
The gap between net and gross consumption is most pronounced in SDG&E territory, where the penetration of rooftop solar has been particularly high. To the extent that the rooftop solar penetration rates in SDG&E are a sign of where the other utility territories are headed in the future, these data are indicative of the potentially regressive impact of continuing to use the effective electricity tax to recover residual costs if net metering provisions are left in place.

Overall, the relationship between household income and net electricity consumption suggests that any system that recovers residual costs through high volumetric prices will tend to be regressive. Next, the researchers turn to calculations that take all of the features of the current system into account and directly estimate residual cost burdens for each household.[18]

Figure 3 summarizes the distribution of residual cost contributions using "box and whiskers" plots. For each income category within each IOU, the dots represent mean values for a given income group; the center bars are medians; the boxes show the 25th/75th percentiles; and the lines outside the boxes (the whiskers) show the range from the 5th percentile to the 95th percentile. These figures show that higher-income households do indeed contribute more on average—the mean and median contribution to residual costs rises modestly across the income categories. This reflects both the fact that higher-income households consume somewhat more energy (as seen in Figure 2) and how other features of the current system—such as CARE, increasing-block pricing and climate zones—impact bills differently by income group.

Despite the fact that higher-income households contribute more, the current effective electricity tax is still quite regressive, with lower-income households contributing a larger share of their income than higher-income households. This is illustrated by the red dashed lines in Figure 3, which present the mean residual cost burden divided by average household income for each category, with the scale indicated on the right-hand vertical axis. While higher-income households do pay more in dollars, the red line shows that these customers pay far less as a fraction of their income. In both the PG&E and SDG&E territories, for example, households in the lowest-income group pay more than 3 percent and households in the second-lowest group pay about 1.5 percent of their annual income towards electricity system residual costs.

FIGURE 2 **Average Gross and Net Electricity Consumption by Income Category**

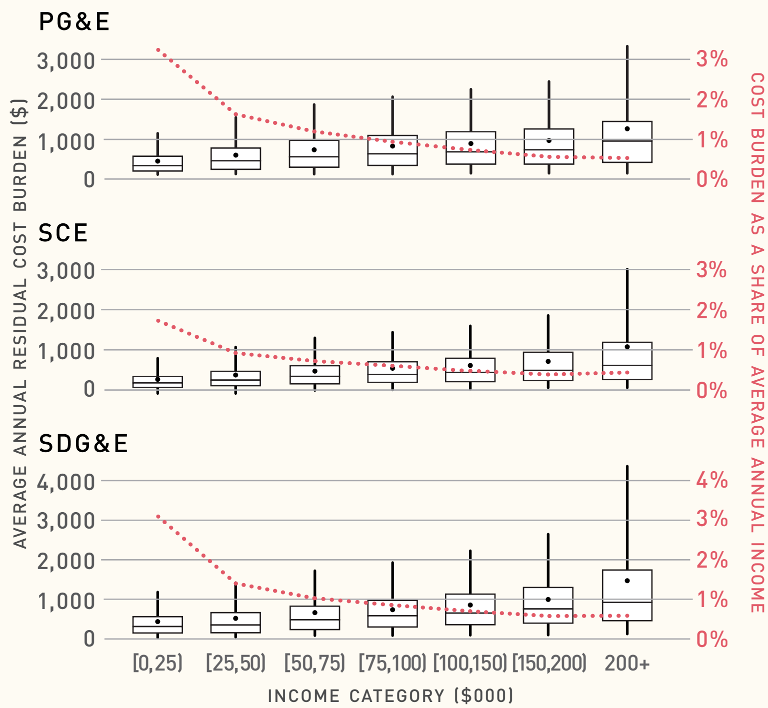


Note: This figure shows the average gross and net consumption of households in each income category by utility in 2019. Gross consumption is estimated by adding estimated solar production for each solar household (based on the size and location of the household's system) to the net consumption observed in billing data.

17 For NEM2.0 customers, the billing structure is somewhat more complicated. These households pay a small (2-3 cents/kWh) non-bypassable charge on electricity exported to the grid that is later used to offset consumption from the grid.

18 In Section 4.1, the authors describe how each of these features impacts the distribution of burdens.

FIGURE 3 **Annual Residual Cost Burden by IOU (2019)**



Note: These figures summarize the residual cost burden in 2019 by income category for each utility. For each income category within each IOU, the dots represent mean values for a given income group; the middle bars are medians; the boxes show the 25th/75th percentiles; and the lines outside the boxes (the whiskers) show the range from the 5th percentile to the 95th percentile. See text for details.

(Total bills are higher than the amounts shown in this figure because the figure includes only the residual cost contributions above social marginal cost.) Higher-income households on average pay well below 1 percent of their income in all three utilities.

Finally, the box-and-whisker elements of these figures illustrate the enormous variation in residual cost contributions paid by different households, both within and across income categories. This owes to the fact that residual cost contributions will scale with net consumption, so that higher net usage households will contribute more, as well as to other features of rates, including climate zones and CARE participation, that impact different households differently. The enormous variation in burdens from the current system imply that any reforms to the retail rate structure are likely to create a wide distribution of gains and losses across households within an income category.

Another way to think about the current method of recovering revenues is to ask how the annual contributions to residual costs will rise for each household as these residual costs increase. Many different factors are poised to drive up non-marginal costs in the next few years, including climate change mitigation and wildfire risk mitigation and damage compensation. Between 2019 and 2022, residential revenue requirements for the three California IOUs rose by an average of 16 percent.[19] There is some variation in the rate of increase across utilities, with SCE seeing the largest percentage increase, while SDG&E has had the smallest in recent years.

To assess the incidence of a 10 percent increase in revenue requirements, Figure 4 shows the implied average increase in annual electricity bills holding household electricity consumption constant at 2019 levels. These calculations assume that the increased revenue requirement is met by increasing retail electricity rates by 10 percent for all customers. Such an increase is projected to raise annual bills by around $75 for the lowest income households. Higher-income households see average increases of $125 or higher.

2.4 Comparison to other state revenue sources

This analysis demonstrates that the approach that California is currently using to raise needed revenues in the electricity sector is regressive; lower-income households spend a larger share of their income on these residual cost recovery contributions. To put this regressivity into context, it can be compared to the regressivity of alternative tax instruments the state could potentially use to raise revenues. More precisely, the authors estimate the progressivity of California's income tax, sales tax, and gasoline tax using survey data from the Bureau of Labor Statistics.[20] These are compared against the progressivity of the effective electricity tax paid under California's

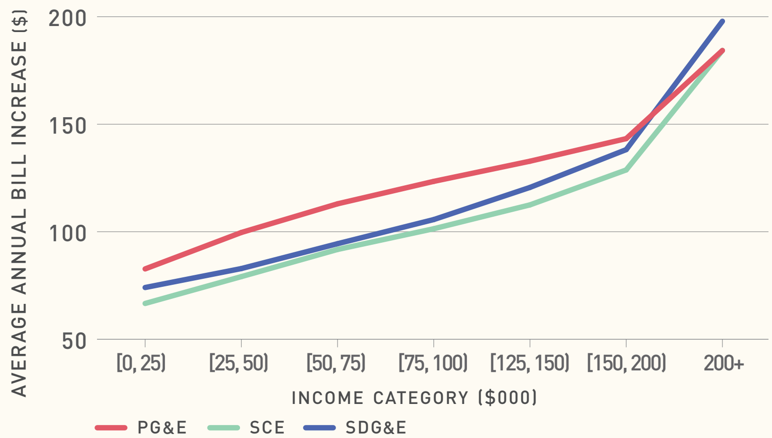
19 Annual revenue requirements (residential) can be constructed using data found in SB 695 (2009) reports based on implementation advice letters.

20 U.S. Bureau of Labor Statistics. Consumer Expenditure Surveys. Available at: https://www.bls.gov/cex/.

current pricing regime.

The 2019 Consumer Expenditure Survey (CEX) interview microdata, which surveys a representative sample of households in the U.S. about their income and expenditures across various consumption categories, is utilized and the responses of households that live in California are analyzed.[21] Based on the income that households report in the CEX, the average taxes for the income categories used in the analysis above are calculated. Consumers report expenditures across a variety of categories. The authors coded each category by whether or not it is subject to the sales tax, and then it is assumed that the sales tax burden of a household is proportional to its total expenditures in those categories—consistent with the fact that the sales tax is a fixed proportion of expenditures in these categories. The CEX directly asks households about their state income tax payments, so this measure is used.

FIGURE 4 Projected Bill Increases by Income Caused by a 10 Percent Increase in Revenue Requirement



Note: This figure shows the average annual bill increase for households in each income category by utility if the revenue requirement for residual customers were to be increased by 10 percent.

Consumers also report expenditures on motor fuels. Recognizing that gasoline taxes are assessed per gallon, the burden of motor fuels taxes are directly proportional to motor fuels expenditures.

The relative progressivity of these different types of taxes are shown in Figure 5. The figure shows the tax burden for each type of tax as a proportion of the tax burden among households with annual income below $50,000.[22] This figure shows that the state income tax is dramatically more progressive than the other taxes. The richest households in the state pay nearly 40 times more than households earning less than $50,000 in annual income. This shows clearly that using the income tax to raise needed revenues would be much more progressive than any other source.

Among the other three taxes, the sales tax is substantially more progressive than the effective electricity tax or motor fuels taxes. Households in the highest income category pay nearly four times more than those in the lowest income category, whereas that ratio is slightly less than three for the electricity tax. The effective electricity tax is comparable to the state's motor fuels taxes, which are widely understood to be regressive.[23]

Shifting some program costs that are currently part of the residual cost recovery to the state budget—for which revenue has historically been raised primarily from income taxes and sales taxes—would increase the progressivity

21 The CEX does not indicate the IOU service territory, so the match between the CEX and billing data is imperfect, as the authors' CEX analysis includes the approximately 30 percent of California households that are served by utility distribution companies other than the three large IOUs.

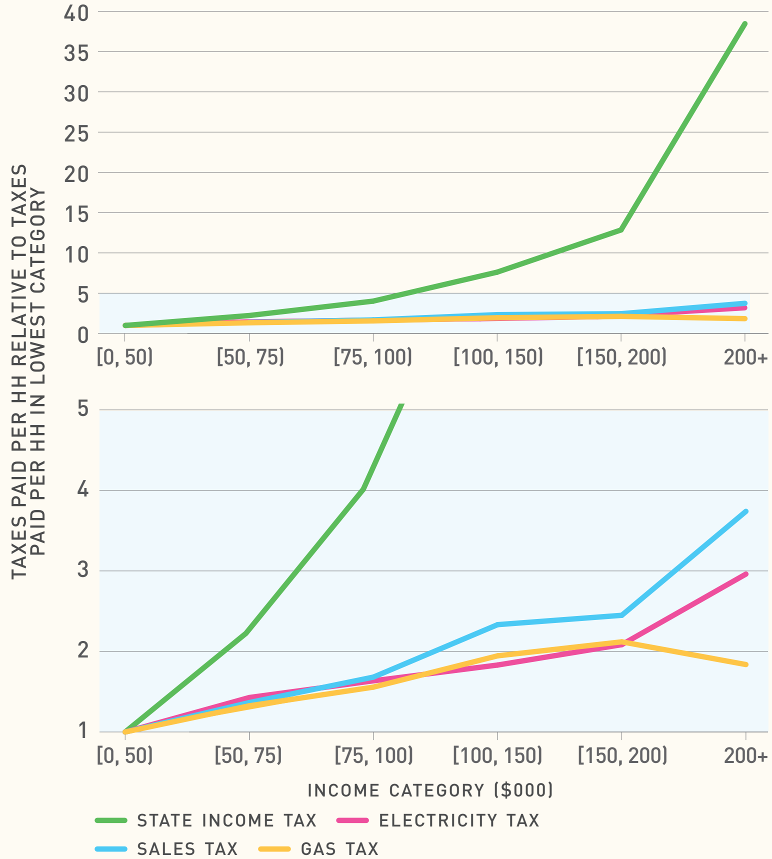
22 This combines two income categories that are shown separately in other parts of this report. The reason this is done is because the average state income taxes paid among households in the lowest-income category (income below $25,000) are negative. In these figures, the researchers want to scale burdens proportional to the lowest-income categories, and this is not a meaningful calculation when some values are negative. Thus, the bottom two categories are combined and shown for each tax how much the average household pays in each income category, relative to the combined lowest income group.

23 This last result differs from a figure in the prior report, *Designing Electricity Rates for An Equitable Energy Transition*, where the electricity tax appeared to be more regressive than the gasoline tax. When writing that report, the report authors did not have access to utility billing data. To assess the regressivity of the effective electricity tax, that report thus relied on self-reported electricity expenditures from that survey and assumed that the effective electricity tax scaled proportionally with expenditures. The method in this report also differs in the source of income data—here it is the imputed measure for approximately 11 million households, whereas before it was based on a direct survey of approximately 2,800. Overall, both methods show that the effective electricity tax is relatively regressive, but it may or may not be more regressive than a motor fuels tax.

of funding these expenses. Doing so would also have regional redistributional impacts, as is the case when any expenses move from local funding sources to the state budget, such as education, health care, or transportation funding. These regional impacts, which would depend critically on the specific programs that are shifted, were not analyzed as a part of this study.

Overall, these data show that, compared to other ways that the state has chosen to pay for public goods and to distribute the cost burden for infrastructure across households, the effective electricity tax is relatively regressive. Reforming rates in a way that lowers the effective electricity tax could have both efficiency and equity benefits. In the remainder of the report, the authors explore the plausible magnitude of efficiency benefits related to electrification and the equity impacts of feasible rate reforms.

FIGURE 5 **Progressivity of Different Taxes in California (2019)**



Note: This figure shows the average burden of different taxes on households by income category, normalized to the burden on households with income below $50,000. The vertical axis is "broken" for visual clarity in order to include the income tax on the same graph as the other taxes. The effective electricity tax is based on IOU billing data (2019), and other taxes are based on the CEX (2019).

ELECTRIFICATION

Setting retail electricity prices at a level that reflects the social cost of electricity consumption—including the monetized damages associated with air pollution and greenhouse gas emissions—is important for encouraging socially efficient choices in energy consumption and conservation. Burdening electricity prices with costs that are not going-forward incremental expenses of supplying electricity is particularly problematic given the central role that electrification is expected to play in decarbonization efforts. Higher retail electricity prices will make it harder to convince households and businesses to electrify.

In this section, the authors assess the extent to which the residential electricity pricing distortion identified increases the operating costs of two key energy-consuming durables: electric vehicles (EVs) and electric space heating. Recent empirical analysis of residential adoption decisions is then leveraged to assess the likely impact of high electricity prices on the market penetration of electric vehicles and electric heating, respectively.

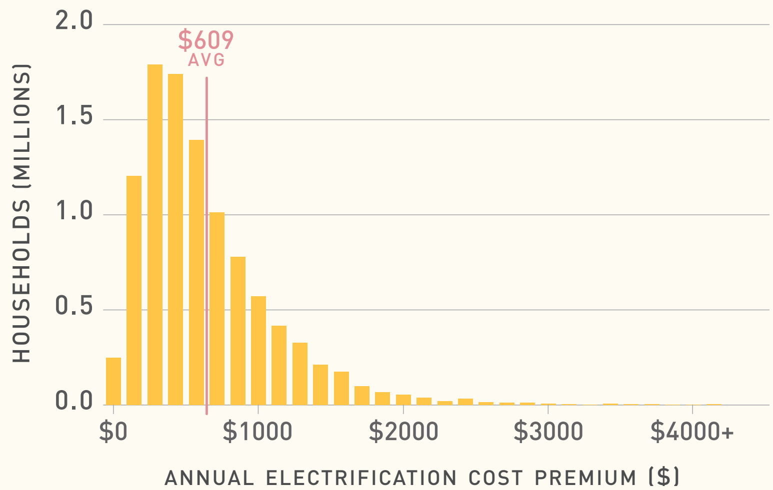
3.1 Electric vehicles

The costs of driving an EV in California will depend on a number of factors including vehicle utilization rates, vehicle charging behavior, and the retail electricity price trajectory over the life of the vehicle. Constructing household-specific estimates of vehicle charging costs is beyond the scope of this study. Instead, the authors use data on vehicle miles traveled by households in California and ask: if all of these households were driving EVs, how would the current practice of pricing above SMC inflate charging costs? The likely effects of these inflated charging costs on EV adoption are then assessed.

This analysis proceeds in four steps:

1. The miles driven by all California households within the three IOU territories are estimated using odometer readings from the most recent National Household Travel Survey (NHTS 2017).[24]
2. These vehicle miles traveled are then mapped to electricity consumption assuming a 0.26 kWh/mile efficiency rate.[25]
3. The quantity of electricity required to charge an EV over a year is then translated into a cost in dollars. As the authors do not observe when households charge their vehicles, they use the average retail electricity price in 2019 to estimate annual vehicle charging costs under observed retail prices. For each vehicle in the survey sample, average residential electricity prices in the corresponding IOU service territory are used to estimate the vehicle charging costs.[26]
4. The authors then calculate how much different annual vehicle charging costs would have been if households paid the social marginal cost of electricity, versus the observed residential retail price. More precisely, EV charging costs under efficient electricity pricing are subtracted from the charging costs implied by observed average retail rates. The authors refer to this difference as the vehicle electrification cost premium.

FIGURE 6 Distribution of Annual Electrification Cost Premia for Vehicles



Note: This figure shows a histogram of the annual increase in charging costs due to electricity prices being above SMC. Each data point is a California vehicle observed in the NHTS (2017). The annual burden estimates the additional charging costs at 2019 retail prices compared to charging cost if retail prices were set at SMC. Calculations are based on the annual mileage reported in NHTS data.

Figure 6 summarizes the authors' estimates of the annual vehicle electrification cost premium that would be paid annually by households in the NHTS sample if all vehicles represented in this sample were EVs. Each

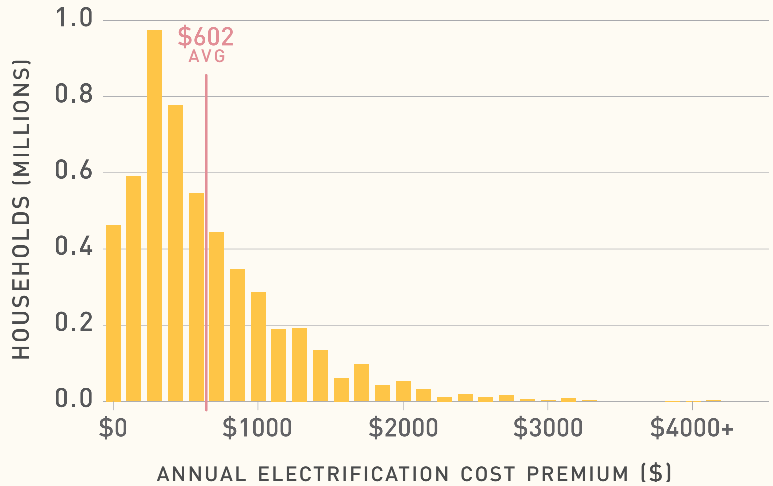
24 U.S. Department of Transportation. 2017 National Household Travel Study. Available at: https://nhts.ornl.gov/

25 Exact mileage ratings vary considerably across EVs, but this corresponds to a fairly efficient EV, and kWh efficiency is improving steadily. See https://ecocostsavings.com/electric-car-kwh-per-mile-list/.

26 California EV drivers are, in principle, eligible for an EV rate that reduces the cost of vehicle charging at specific times of day. Bushnell, Muehlegger and Rapson (2022) reports that from 2014 to 2017 over 90 percent of California EV owners were on standard residential rates rather than special EV rates. Implicitly, this calculation assumes that all charging is done at home or that the cost of charging at other locations has the same markup above SMC. (Bushnell, James, Erich Muehlegger, and David S. Rapson. 2022. "Energy Prices and Electric Vehicle Adoption." Energy Institute at Haas Working Paper 326.)

data point in this distribution is a vehicle observed in the NHTS. Variation comes from differences in mileage, as reported in the NHTS, and differences in retail rates across IOU service territories. These data show that, on average, drivers considering adopting an EV face annual operating costs that are more than $600 above the costs they would face if prices were set equal to SMC. Many higher mileage customers face burdens in excess of $1,000 per year. As such, the effective electricity tax in California translates into a substantial increased cost of driving an EV.

FIGURE 7 Distribution of Annual Electrification Cost Premia for Space Heating



This figure shows a histogram of the annual increase in space heating costs due to electricity prices being above SMC. Each data point is one single-family detached dwelling in the RASS. The annual burden estimates the additional operating costs at 2019 retail prices compared to operating cost if retail prices were set at SMC.

Presumably, high charging costs have discouraged some drivers from purchasing an electric car. Estimating the extent of this impact is complicated because it will depend on relative fuel prices, consumer preferences, and the extent to which consumers pay attention to fuel prices when making their vehicle choices. The likely impacts of California's high retail electricity prices on EV adoption was assessed based on the recent work of Bushnell, Muehlegger and Rapson (2022).[27]

Using EV registrations in California, together with detailed gasoline and electricity price data from 2014 to 2017, Bushnell et al. (2022) considered the relationship between retail electricity prices, gasoline prices, and EV adoption. The authors of that study estimated an empirical model of households' EV adoption choices. They exploited the fact that retail electricity prices vary significantly across investor-owned utilities and municipal utilities. They first used data from all California households to estimate the model. However, because higher electricity prices can be correlated with other factors (such as income), Bushnell et al. were concerned about confounding the effects of higher electricity prices with the effects of other correlates. To address this concern, they repeated the estimation exercise using data from only those households living close to utility service territory borders, ensuring that households facing different electricity prices across the border are similar in other respects.

This report used both sets of empirical results from Bushnell et al. to simulate the effects of the retail electricity price distortion on EV adoption in California. First, data that represents all residential IOU customers were used to simulate EV adoption under observed retail electricity and gasoline prices over 2014-2017. The model was then used to simulate EV adoption in a counterfactual scenario in which IOUs charged retail electricity prices equal to the social marginal cost of electricity consumption. Simulated EV adoption was 13 percent higher under efficient retail electricity pricing. When the exercise was repeated using only households living close to service territory borders, EV adoption was 33 percent higher under efficient electricity pricing. This larger effect is due in part to the fact that this subset of households is wealthier on average and less likely to live in multi-unit dwellings.

3.2 Electric heating

Turning to building electrification, the authors used data from the RASS survey to construct a representative distribution of space heating service demand across

27 Bushnell, James, Erich Muehlegger, and David S. Rapson. 2022. "Energy Prices and Electric Vehicle Adoption." Energy Institute at Haas Working Paper 326.

California households.[28] The RASS data were used to establish a distribution of annual household-level heating service demand. Assuming that electric heating efficiencies were in line with the 2019 Energy Star standard, this distribution of heating services can be mapped into a distribution of annual electricity consumption.

Following a similar approach to the one outlined in the preceding subsection, the electric heating costs that would be incurred under efficient electricity pricing were then subtracted from the heating costs that would be incurred to heat with electricity under the retail electricity prices observed in 2019. Figure 7 summarizes the distribution of implied annual heating electrification cost premium paid by households represented in the RASS sample. The figure shows how California's high retail electricity prices increase the cost of heating homes with electricity quite substantially. Using 2019 retail prices, the average heating electrification cost premium exceeds $600 per year.

Davis (2022) provides a roadmap to assessing the likely impact of these cost distortions on households' heating fuel choices.[29] Davis analyzes the heating fuel choices observed at newly constructed homes. His model of heating fuel choice incorporates a variety of factors that could influence this choice including fuel prices, climate, income, housing type, and geography. By far, the single most important factor driving the heating fuel choice is fuel prices.

Davis's heating choice model is used here to simulate observed and counterfactual home heating fuel choices, focusing exclusively on California homes constructed post-2009. When the choice model is calibrated using observed fuel prices, the model predicts that 42 percent of new California homes choose electric heat. This is close to the 39 percent adoption rate actually observed over this time period. When the model is used to predict what these heating fuel choices would have looked like under a counterfactual scenario in which retail electricity prices were set at social marginal cost, the predicted share of homes choosing electric heat increases to 56 percent, about a one-third increase in home heating electrification.

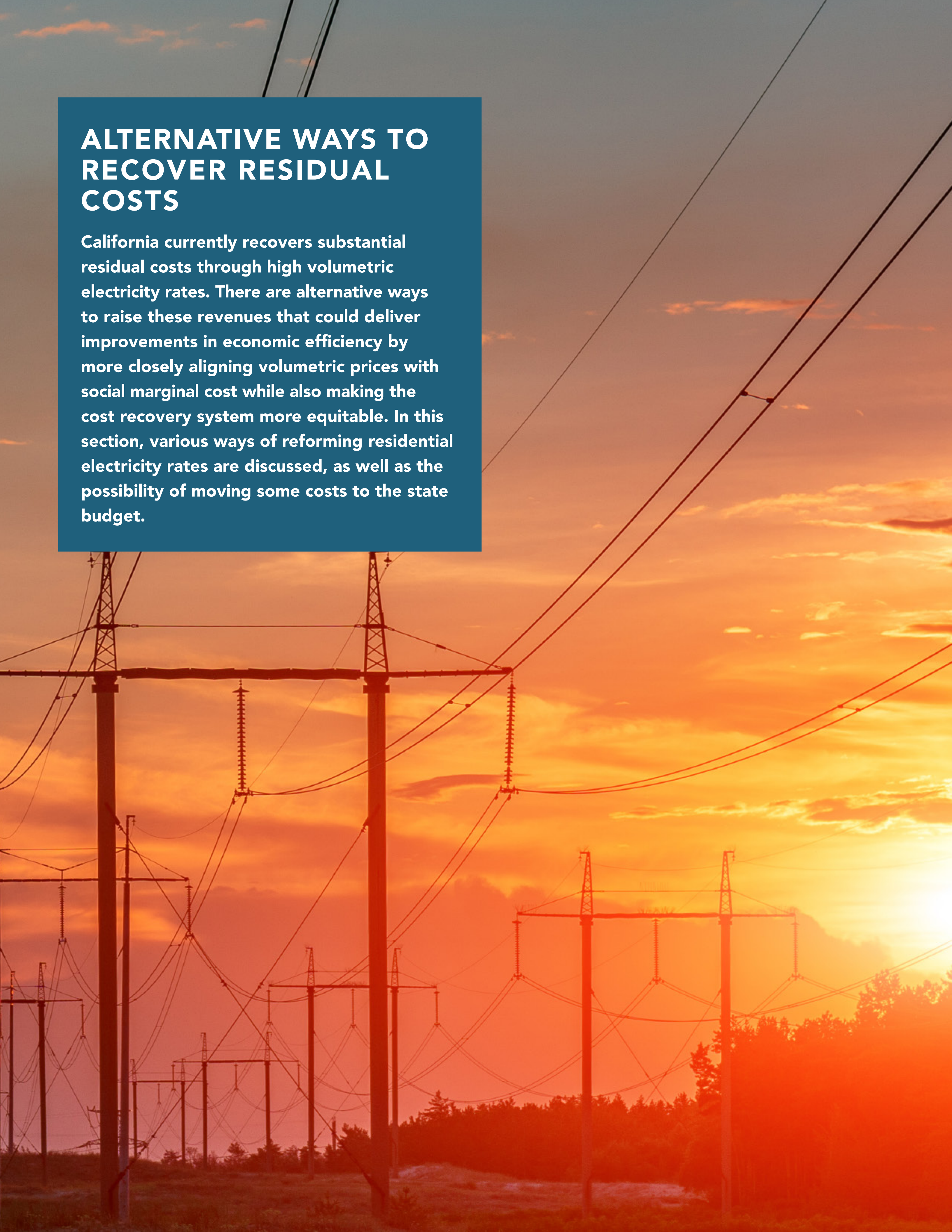
3.3 Electricity consumption taxation slows the pace of electrification

In summary, the current practice of recovering non-incremental costs in higher retail electricity rates has significantly increased EV charging costs and electric heating costs. Leveraging retrospective empirical analyses of households' technology adoption choices, the authors find that these high retail electricity prices have substantially slowed the pace of home and transportation electrification.

Looking ahead, special retail rates could be designed to mitigate the extent to which high retail rates slow technology adoption. However, this could shift costs to non-adopters, with the associated equity and efficiency concerns. The state has also pledged to spend billions on subsidies to accelerate transportation and building electrification. These subsidies could have a much bigger effect on the pace of electrification if retail prices more closely approximated social marginal cost.

28 Estimates of heating service demand are taken from Borenstein and Bushnell (2022). Following that analysis, this study focuses on the 27,583 single-family detached dwellings in the RASS (thus excluding apartments and mobile homes). (Borenstein, Severin, and James B Bushnell. 2022. "Headwinds and tailwinds: Implications of inefficient retail energy pricing for Energy substitution." Environmental and Energy Policy and the Economy, 3(1): 37–70.)

29 Davis, Lucas W. 2022. "What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices." Energy Institute at Haas Working Paper 309.



ALTERNATIVE WAYS TO RECOVER RESIDUAL COSTS

California currently recovers substantial residual costs through high volumetric electricity rates. There are alternative ways to raise these revenues that could deliver improvements in economic efficiency by more closely aligning volumetric prices with social marginal cost while also making the cost recovery system more equitable. In this section, various ways of reforming residential electricity rates are discussed, as well as the possibility of moving some costs to the state budget.

4.1 Could modifying the existing rate structure reduce regressivity?

Some might be surprised that California's retail electricity pricing regime is not more progressive. After all, the existing system has several important features, including CARE, climate zones and increasing-block pricing, that are designed to ensure affordability and foster progressivity. One might wonder why those features are not sufficient, or whether it is possible to simply augment them to achieve a fairer distribution of the necessary cost recovery.

In this section, the detailed billing data are used to disentangle the impacts of the different features of the current regime that determine how residual costs are allocated across households. The authors do so by calculating how much households in each income category would end up contributing to residual costs if certain features of rates were changed, assuming that each household's electricity consumption is held constant at 2019 levels, and that the overall revenue requirement for the utility is unchanged.

The average residual cost burden across households within each income category is shown in Figure 8 for each utility. The black lines show the average annual burden for each income group under the current system. (This is identical to the mean values (the dots) in Figure 3.) The other lines show how these annual burdens are reallocated (on average) as the following features are removed: increasing-block pricing (tiers), climate zones, CARE, and net metering for rooftop solar. In what follows, the report discusses how removing each of these features affects allocation of the residual cost burden.

4.1.1 Increasing-block pricing

Method: To separate the effects of increasing-block pricing from the effects of climate zones, flat volumetric electricity rates are created within each utility/climate zone so as to hold constant the average rate for that utility/climate zone.[30] In this scenario, CARE customers continue to get the same average discount within each utility. The single volumetric rate that would yield the same total revenue as the current system is calculated assuming consumption is held constant within each utility/climate zone. For each household, the authors then calculate their monthly bill under this alternative price. Finally, each household's annual contribution to residual costs is calculated, which is equal to their bill payments minus the social marginal cost times consumption (as defined in Equation 1).

Impact: The yellow lines in Figure 8 shows these burdens if tiers are eliminated. Tiers do make the current system more progressive, but the impacts are modest. For example, the elimination of tiers would lower the annual burden on the wealthiest households served by PG&E by around $50 for PG&E, and only slightly raise the contributions to the five lowest income groups.

4.1.2 Climate zones

Method: Next, the impacts of eliminating both tiers and climate zones, while preserving the assumption that there is a single volumetric rate rather than tiers, is considered. The authors calculate a single volumetric rate for the entire area served by each utility, again assuming that consumption is held constant at 2019 levels and that the utility is set to recover the same total revenue across its entire service territory. Again, the percentage CARE customer discount is assumed to be unchanged.

Impact: Eliminating climate zones yields no significant impact on equity—the lines for the no tiers case and the no tiers plus no climate zone case in Figure 8 are so close that they are nearly indistinguishable for all three utilities.[31]

4.1.3 CARE

Method: The authors assess how burdens would change if the CARE program was eliminated. This is done by calculating the utility-wide single volumetric price that would be needed to recover utility revenue assuming no CARE discount with current consumption levels.

Impact: This scenario is shown in blue in Figure 8. If CARE discounts were eliminated, the distribution of burdens would flatten substantially, as one would expect. In other words, CARE is making the system more progressive in terms of how residual costs are allocated

30 Throughout this analysis, the report authors abstract away from any discussion of time-varying pricing. Price signals that convey information about variable real-time market conditions can deliver important efficiency gains; incremental costs can be significantly reduced via improved coordination of demand and supply. However, these efficiency gains pertain to incremental costs, including incremental capacity costs. Recovering non-incremental costs in higher retail electricity prices distorts consumer prices, whether they are dynamic or not.

31 Note that this does not necessarily imply that eliminating climate zones while preserving increasing block pricing would have no equity impact. Rather, the decomposition peels back the layers of the current system cumulatively.

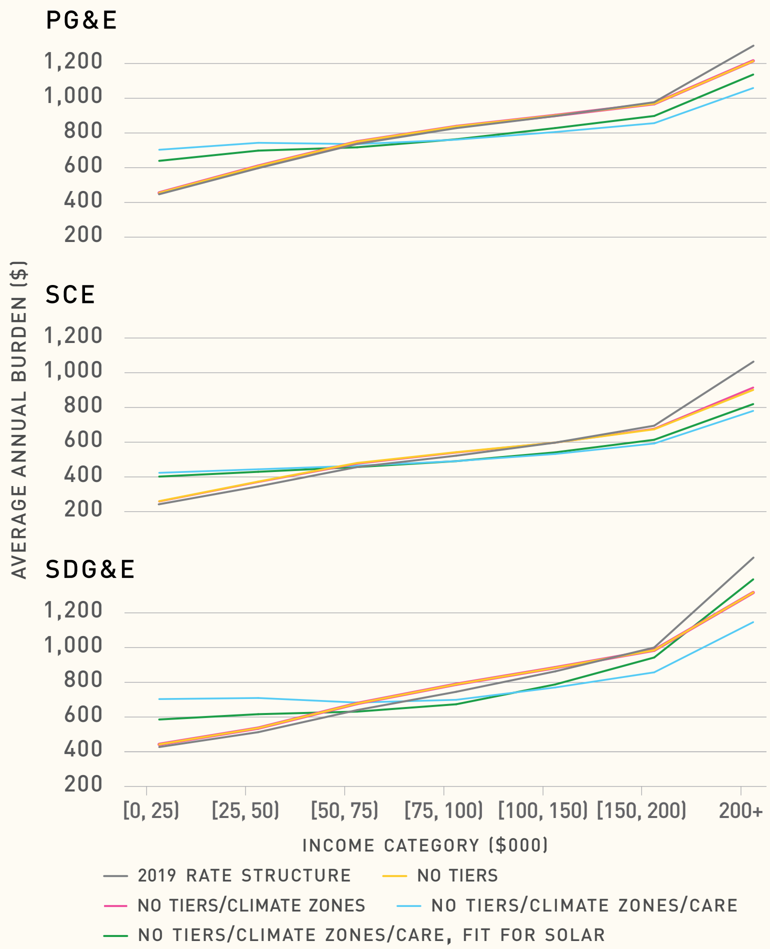
across households. Absent CARE, average residual cost burdens would be quite similar over the entire income distribution, with only the very highest income category paying noticeably more.

4.1.4 Net metering

Method: The last step is to suppose that, in addition to all of the other changes, compensation for rooftop solar generation is reformed. Under the current net metering policy, electricity generated by residential solar systems is compensated at the retail price. Because the retail price exceeds the true social marginal cost by a significant (and growing) margin, this amounts to a significant (and growing) subsidy, as discussed in *Designing Electricity Rates for An Equitable Energy Transition.*[32] An alternative policy would compensate rooftop solar at a level that is commensurate with the social benefit generated (including the value of avoided fuel costs, avoided climate impacts, and avoided local air pollution). The authors of this study consider a regime that replaces net metering with a feed-in-tariff, under which all rooftop generation is sold to the grid at social marginal cost.

To model this change, the authors use their estimates of gross consumption (i.e., grid electricity consumption plus solar electricity generation for households with rooftop solar), and assume that bills rise by the difference between the prevailing electricity price and social marginal cost multiplied by the estimated output of the solar system. This raises more revenues from households with rooftop solar, thus lowering the bills of non-solar customers (because the prevailing uniform volumetric price needed to recover residual costs will be lower).

FIGURE 8 Annual Residual Cost Burdens Under Rate Alternatives (2019)



Note: This figure shows annual average residual cost burdens under current system as well as counterfactual rates that unwind specific features, assuming constant consumption and an unchanged revenue requirement.

Impact: Comparing the green lines to the blue lines shows the impact of net metering. Replacing net metering with a feed-in tariff (FIT) that compensates rooftop solar generation at the social marginal cost would make the system less regressive. The impact of net metering varies across utilities, consistent with the pattern of rooftop solar penetration. In SDG&E territory, net metering unwinds a significant majority of the progressive impact of CARE subsidies. The impact in SCE territory is much more modest, and PG&E is between those two cases. Still, the impact is likely to rise as solar continues to expand unless there is a dramatic change in the income distribution of those getting rooftop solar.

32 Borenstein, Severin, Meredith Fowlie, and James Sallee. Designing Electricity Rates for An Equitable Energy Transition. Next 10 and the Energy Institute, February 23, 2021. Available at: https://www.next10.org/publications/electricity-rates.

In sum, this analysis makes clear that features of the current system do in fact determine the progressivity of the effective electricity tax in important ways, and in particular that CARE is an important program that improves equity. But, even with these features in place, the current system is quite regressive.[33] One could imagine seeking to improve the progressivity of the current system by altering these features. In particular, one might advocate for a more expansive and more generous CARE program. However, any scheme that simply makes CARE more generous in exchange for further raising volumetric rates on non-CARE customers is exacerbating mispricing for non-CARE customers and raising the effective electricity tax that threatens to deter electrification. Moreover, CARE as currently constructed is a blunt instrument that provides the same price reduction to all participating households, whereas it might be better to offer bigger benefits to those with the very lowest incomes.

Instead, the authors advocate for more careful consideration of alternatives, including shifting expenditures to the state budget or the use of income-based fixed charges, because these reforms can be better targeted and deliver efficiency and equity improvements simultaneously.

4.2 Moving selected costs to the state budget

In principle, any source of revenue can be used to pay for residual electricity costs, including the general state budget. Shifting even a limited set of budgetary costs from the electricity payment system to the state budget could have significant impacts that would slow the rise of rates. For example, it has been estimated that wildfire-related costs increased retail electricity rates by six to nine percent in 2021.[34]

Moving costs onto the state budget is likely to be both more efficient and more equitable than the status quo. In terms of equity, as detailed above, the main sources of state revenue—the income tax and the sales tax—are more progressive than the effective electricity tax, so shifting more of the burden onto those tax bases will increase progressivity.

In terms of efficiency, it is important to note that increasing either the sales or income tax has distortionary effects in the economy associated with taxing real wages. The efficiency consequences of increasing these taxes could be important, but at current levels, it is highly likely that the distortion from the effective electricity tax is larger than the distortion from raising the same amounts through these other taxes. The reason is that one of the key determinants of economic distortions from a tax is the size of the wedge between the price and social marginal cost, and this wedge is much larger in electricity than in labor markets. That said, a full accounting of these efficiency trade-offs is an important topic for future research.

In what follows, utility revenue requirements are held constant so as to evaluate alternative approaches to raising these revenues in terms of both efficiency and equity. There are likely steps the state could take to reduce system costs. Although important to consider, cost containment is beyond the scope of this analysis.

4.2.1 Criteria for shifting items onto the state budget

How might policymakers decide which costs would be most appropriate to move onto the state budget? The authors suggest three criteria, which are summarized as alignment, incentive compatibility, and stability.

Alignment reflects the extent to which an activity is central to an electric utility's basic function of providing (or procuring) generation, transmission, and distribution of electricity in a socially cost-minimizing way. For political and administrative reasons, less-aligned items seem likely to be leading candidates for shifting to the state budget.

Incentive compatibility refers to the impact of cost assignment on the incentive of decision-makers to make choices that are socially beneficial. If a utility has wide discretion over expenditures in an area and has strong private incentives to deviate from socially optimal choices, then assigning those costs to the state budget is likely to exacerbate incentive conflicts by disassociat-

33 One feature that has not been discussed here, in part because it is presumably a short-term response to COVID-related stressors, is the California Arrearage Payment Program (CAPP). This program uses funds from the state budget to provide debt relief to utility customers who have accumulated arrears over the COVID-19 pandemic period. This program would raise moral hazard issues if it became a permanent feature in the policy landscape. Moreover, it may also raise fairness issues insofar as low-income households who struggled, but managed to pay bills on time, would receive no benefits under the program.

34 CPUC. 2021. "Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues." California Public Utility Commission Working Paper.

ing those costs from the utility. On the other hand, if a category of expenditures is largely exogenous to the utility, then shifting those costs to the state is less likely to create inefficiencies.

Stability reflects the belief of some that putting costs or programs onto the state budget potentially puts them at risk of being cut or of having funding delayed, depending on changing political preferences, budgetary conditions, or just the sluggishness of the budget process. At the same time, others argue that regular scrutiny of program funding is exactly the sort of budget priorities debate that should take place in the legislature, and that the stability of funding for projects paid for through utility bills is a byproduct of a problematic lack of oversight. The report authors are agnostic about the weight that stability should receive, but recognize that it is an important factor in the political debate over which costs might be moved onto the state budget.

4.2.2 Costs that potentially could be shifted to the state budget

A complete analysis of moving specific costs to the state budget is beyond the scope of this report, but these costs that have been suggested as possible candidates for state funding.

Public purpose programs. Currently, volumetric electricity rates are used to pay for many state policy initiatives, including improving energy efficiency, rolling out EV charging stations, and discounting electricity for qualified low-income customers and customers with critical medical devices that require electricity. Some of these costs are explicitly part of the public purpose charge, while others are not.

What all of these programs have in common is that they are not directly aligned with the central utility function of providing generation, transmission, and distribution. Rather, they are state public policy initiatives paid for through volumetric electricity rates. As such, they are probably among the easiest to split off from utility budgets and shift to the state budget. They also generally present the fewest incentive issues when moved to the state budget. The primary concern that has been voiced in response to such a proposed shift is the stability issue, particularly with regard to programs for the benefit of disadvantaged households. However, comparable programs that support food (CalFresh) and medical care (MediCal) for low-income households are part of the state budget, rather than being paid for through higher prices on food and medical care for other customers.

Another policy priority currently paid for through retail rates is the subsidy for rooftop solar and other behind-the-meter resources through net metering. Though the subsidies themselves are highly controversial, any level of subsidy decided upon could be paid for through the state budget. Direct compensation for these resources through the electricity system could then be based on their value to the electricity system.

Past purchases of renewable energy at above-market prices. With the current extremely low cost of grid-scale wind and solar, renewable energy procurement today is largely cost competitive, but that has not always been the case. Utilities hold many long-term contracts for renewable energy that were purchased at well above market prices. The excess cost of buying renewables at the time was driven by state policies to support early-stage renewable technologies and help them to scale up, so it was not aligned with the basic utility function. These contracts could be transferred to a state entity and the loss from selling that power in the wholesale market could be borne by the state rather than the utility. Transferring these contracts seems to present little incentive conflict for utilities, nor does it create funding stability risks, because the state would be legally liable for the contracts.

Existing power contracts that are now above market. While older renewables contracts were signed years ago recognizing that the price was above market, other contracts for conventional power were signed at prices that were expected, on average, to equal market prices. Some of those contracts, however, were signed at times that the market price of power was expected to be substantially higher than it has turned out to be, particularly contracts signed before the fracking revolution drastically lowered the price of natural gas. The state could take over these contracts and effectively cover the losses from their above market prices. This would, however, be difficult to support on the alignment argument, because power procurement is a basic function of the electricity sector, through a vertically-integrated utility or some other load serving entity. It would also raise incentive compatibility issues if utilities didn't see this as a one-time action, but thought that the state might in the future bail them out of contracts that turn out to be uneconomic.

Wildfire mitigation and adaptation costs. Transmission and distribution utilities have always had robust vegetation management activities in order to reduce the risk of fire starting from contact between their lines and nearby vegetation. With extreme drought, reduced humidity, and rising temperatures, the danger has greatly increased in the last decade. Utilities are now spending much more than in the past on vegetation management, improved grid monitoring and near-instantaneous shut off when a fault is detected, and advanced technologies to harden infrastructure against fire risks. These costs could certainly be seen as resulting from climate change, a disaster outside the control of these utilities or their customers. Thus, while these activities are aligned with basic utility operations, an argument could be made for state funding in the same way that state and federal governments offer aid to households and businesses to help them cope with other disasters beyond their control. Such aid, however, typically raises incentive and verifiability concerns. It is difficult to verify exactly how much of utility expenditures on these functions are due to the changing climate, and utilities would have an incentive to attribute normal grid management costs to climate change.

Wildfire victim compensation costs. Few people would disagree with forcing utility shareholders to bear the cost of wildfire losses when the utility has been negligent, but under California's inverse condemnation law, utilities are also bearing the losses when they are not found to be at fault. Those costs are passed along to ratepayers. Given that utilities are not found to be negligent in cases covered by inverse condemnation, incentive problems with the state covering these costs may not be large, though attributing fault is typically not unambiguous. There are significant legal complexities with changing the conditions under which the utility is responsible for compensation, but given that these costs already play a significant role in driving rate increases and will likely become more significant, this issue seems worth exploring further.

Transmission and distribution. One of the largest causes of the gap between retail price and SMC is the fixed costs of transmission and distribution (T&D). This is true in any electricity grid simply because there are very large economies of scale in building out capacity for moving electricity.[35] In California, however, the push for electrification will increase these expenditures and expanded use of renewables will increase transmission costs further. Thus, some T&D costs are more closely related to policies of electrification and decarbonization, while others are part of the basic utility function.

There are different models that could move these expenses off of bills. The simplest model would be to still have T&D expenses overseen by the CPUC, but some approved expenses would then be paid from the state budget rather than added to the revenue requirement that drives rates. Utilities would still own the wires and their compensation would include a rate of return on their investment. One alternative model for transmission would be state ownership: when new transmission is deemed necessary, the state could procure construction services from the private sector through a bidding process (as is now done with highways and bridges) and then turn over the operation of the transmission to the California Independent System Operator (CAISO), as utilities that are part of the CAISO now do. A more extreme change would be for the state to purchase existing transmission and distribution lines from utilities (investor-owned and municipally-owned) to create a state-owned grid. That would, however, turn utility functions into state responsibilities and change the ownership of billions of dollars of capital, which would almost certainly be tied up in years or decades of litigation.

4.2.3 Redistribution across utilities

One potential political barrier to moving expenses to the state budget is that it would likely redistribute costs regionally across utility boundaries. To take just one example, a far higher share of PG&E customers qualify for the CARE program—households with income below 200 percent of the federal poverty level—than is the case for many of the municipal utilities that operate inside the boundaries of the area PG&E covers. The cost of PG&E's CARE discount is covered by higher rates for PG&E's non-CARE residential customers and for its commercial and industrial customers. Moving CARE to the state budget would place the burden of the program on all California taxpayers regardless of where they live. The same would be true for other public purpose programs and any of the other expenses discussed in the previous subsection to the extent they are not distributed uniformly across different service territories. It is hard to

35 Transmission does generate some revenue directly through congestion revenue rights, but that is typically far less than the cost of the investment if the capacity is optimally sized.

know which utility customers would be net winners or losers from such changes. Nor is it obvious which costs should be spread across the entire state rather than across the customers of a given utility. Still, it is important to acknowledge that a burden shift would follow from moving expenses from utilities to the state.

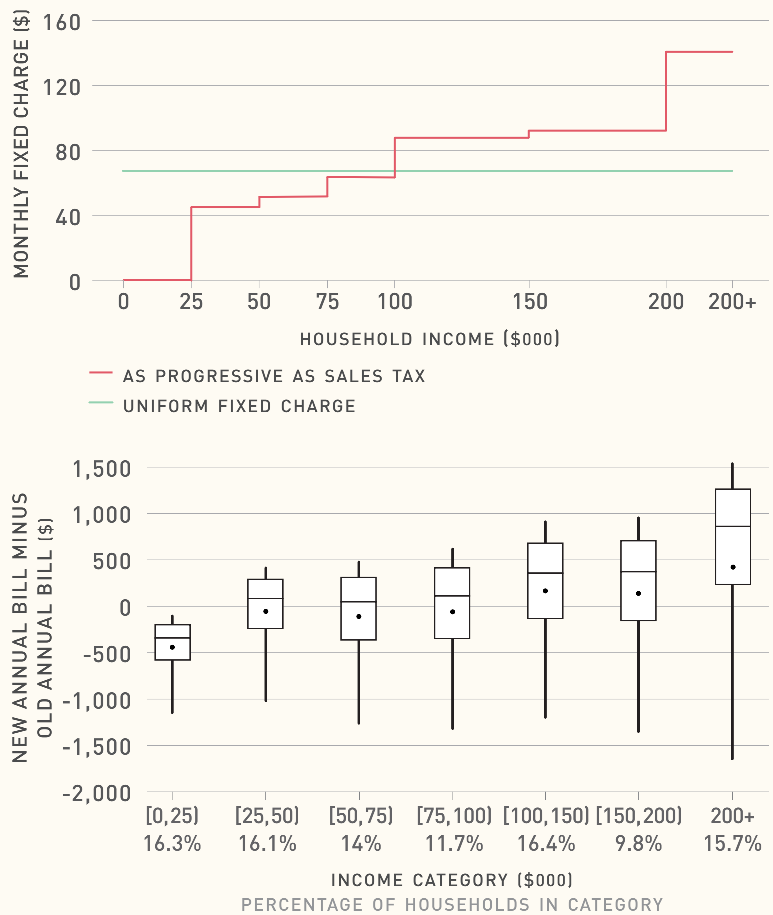
4.3 Income-based fixed charges

In the prior companion report to this study, *Designing Electricity Rates for An Equitable Energy Transition*, the authors proposed an income-based fixed charge (IBFC) as a promising alternative to the current rate structure. A key challenge to implementing an IBFC is that the utility needs to access credible information about income for all of its customers. The first report discussed this challenge and described alternative ways that utilities could interact with state agencies to overcome it.

Here, the authors extend their analysis of how an IBFC would impact the allocation of the residual cost burdens across the income distribution. Specifically, they study a case in which retail rates are set equal to social marginal cost, and remaining revenue is recovered via the IBFC. Their calculations continue to make the simplifying assumption that each household consumes the same amount of electricity after the reform as before. Changes in the bill for each household are then calculated. Bills are pushed up by the fixed charge for all but the lowest income households. However, bills are pushed down due to lower volumetric prices. The net impact on total bill will vary across households depending on consumption levels (more consumption implies a larger savings due to the reduced volumetric price) and income (higher income will be associated with a higher fixed charge). Pricing all electricity consumption at the SMC eliminates tiers and CARE, which also impacts the estimates of bill changes.

There are many potential IBFC schedules that could be considered. The authors focus on an IBFC schedule that is designed to be approximately as progressive as the state's sales tax and varies across discrete income categories. They design a schedule that recovers the necessary revenue and requires no fixed charge for the lowest income category (households with annual income below $25,000), and then imposes a fixed charge on all of the other income categories that is the same ratio relative to the second income category as is created by California's sales tax, the calculations of which are described above. This is a useful benchmark because it mimics the progressivity of the sales tax and limits the complexity of

FIGURE 9 Monthly Fixed Charge Schedules and Change in Annual Bills Under Income-Based Fixed Charge (PG&E)



Note: The top panel shows two fixed charge schedules that would recover the 2019 PG&E residential revenue requirements had volumetric rates been set to SMC. The flat teal line shows the monthly fixed charge for all households if charges are uniform. The red step line shows an income-based fixed charge that mimics the progressivity of the sales tax. The bottom panel shows the distribution of the change in annual bills, holding household electricity consumption fixed, for PG&E households in each income category. This change is induced by moving households from the status quo to an IBFC pegged to the progressivity of the state sales tax. A negative number indicates that bills would go down under an IBFC. The percentages below the income categories indicate the share of households falling into each category.

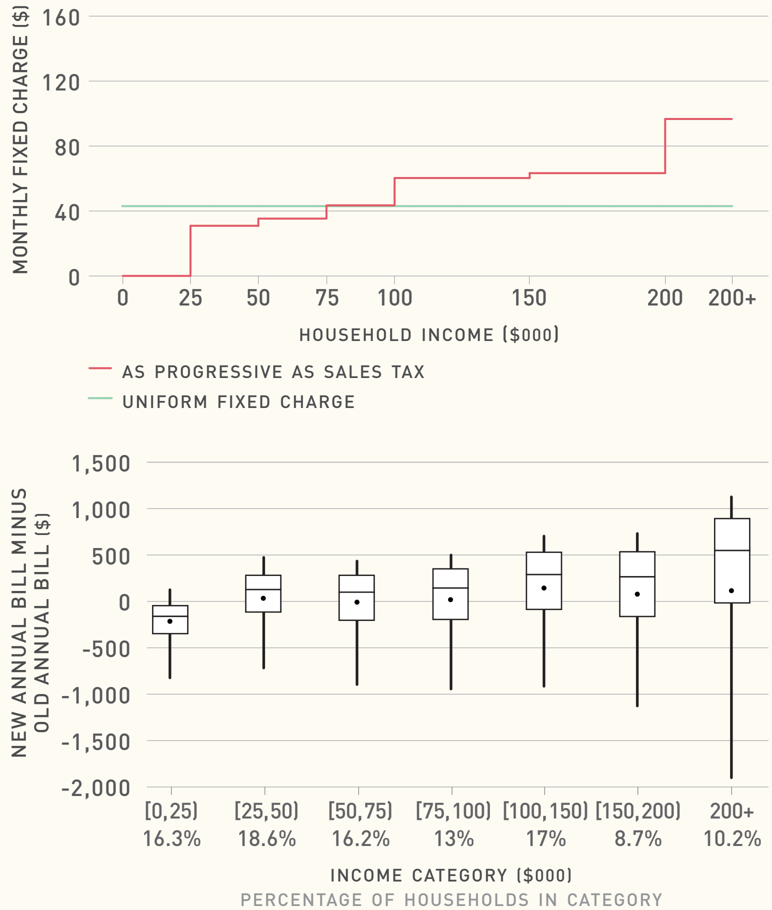
the schedule by having only a few tiers, but it is worth emphasizing that this is only one illustrative possibility.

The implied monthly fixed charge schedules are shown in Figures 9, 10, and 11. The flat horizontal lines in the figure show the uniform monthly fixed charge that would be required in each service territory if prices were set at social marginal cost and the fixed charge were not income-graduated. For PG&E, this is a monthly charge of $67 per household, with the corresponding numbers equal to $43 for SCE and $65 for SDG&E. As in all scenarios analyzed, the average bill change is zero in this scenario. This potential fixed charge is used mainly as a reference point for understanding an IBFC.[36]

An IBFC that mimics the progressivity of the state's sales tax is shown in the red step function. In all service territories, the fixed charge is constrained to be zero for the lowest income households, but the highest income category (those making over $200,000 per year) would pay $141 per month in PG&E, $97 in SCE and $138 in SDG&E.

The bill impact of these fixed charges is offset to varying degrees across households by the reduction in the volumetric price. Panel B in Figures 9, 10, and 11 show the distribution of annual bill changes across and within income categories. For each income category within each IOU, the dots represent mean changes for a given income group; the bars are medians; the boxes show the 25th/75th percentiles; and the lines outside the boxes (the whiskers) show the range from the 5th percentile to the 95th percentile. A negative value indicates that bills fall under the IBFC as compared to the status quo. Again, the average bill change across all households is zero by construction, but, as the figure shows plainly, there is a great deal of variation in bill impacts across households.

FIGURE 10 **Monthly Fixed Charge Schedules and Change in Annual Bills Under Income-Based Fixed Charge (SCE)**



Note: The top panel shows two fixed charge schedules that would recover the 2019 SCE residential revenue requirements had volumetric rates been set to SMC. The flat teal line shows the monthly fixed charge for all households if charges are uniform. The red step line shows an income-based fixed charge that mimics the progressivity of the sales tax. The bottom panel shows the distribution of the change in annual bills, holding household electricity consumption fixed, for SCE households in each income category. This change is induced by moving households from the status quo to an IBFC pegged to the progressivity of the state sales tax. A negative number indicates that bills would go down under an IBFC. The percentages below the income categories indicate the share of households falling into each category.

In all service territories, the average (mean) bill will decrease or be very close to zero change for households in the first four income categories, which accounts for roughly 60 percent of the population. Bills rise on average for wealthier households. However, there are winners and losers within every income category except the lowest income group, which is assumed to pay no fixed charge and thus enjoys a volumetric price drop without any offset-

36 A similar analysis was provided in the first report in this study, but there it was limited to characterizing the impact on the average household. With this billing data, the report authors can characterize the full distribution of bill changes across households with different consumption and income.

ting fee, so all such bills decrease. This wide variation in impacts is due primarily to differences in consumption, rooftop solar, and CARE participation.

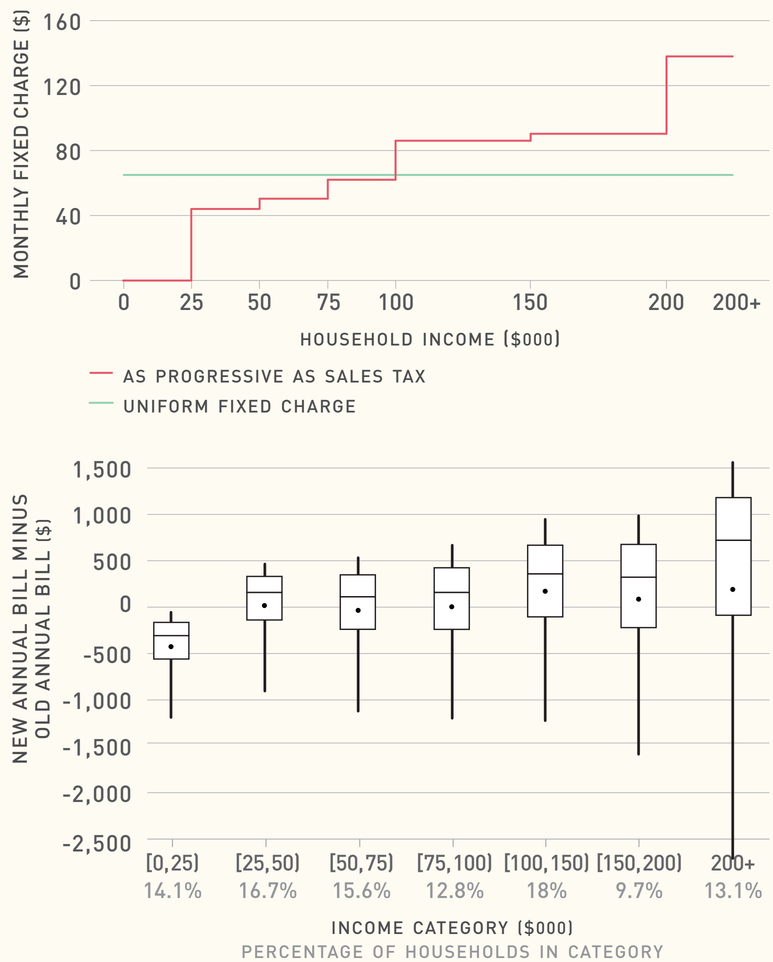
In sum, an IBFC can easily be designed to be progressive overall, but it is important to keep in mind that it creates a complicated set of changes in rates that would lead to a redistribution of impacts across households both within and across the income distribution.

4.3.1 Why not just use the income tax?

Using an income-based fixed charge to reallocate electricity-related costs may seem unnecessarily complicated. If the state wants to give more money to people with lower income, why not do so via the state income tax or other social programs, rather than trying to use utility bills to achieve equity goals? Indeed, this line of thinking has a long tradition in public economics, where there is a presumption that certain tools, like an income tax or universal education, should be the primary levers used to achieve equity goals. Other policies should stay focused on the issues directly in their purview.

This line of reasoning can lead in two directions. One is to conclude that, rather than inventing an income-based fixed charge, regulators and policymakers might simply shift more costs onto the state budget, and use the income tax to cover the costs. This is in line with the authors' thinking in the prior section, which advocates shifting some costs to general state revenue, though it raises issues of redistribution across utilities, as discussed above.

FIGURE 11 Monthly Fixed Charge Schedules and Change in Annual Bills Under Income-Based Fixed Charge (SDG&E)



Note: The top panel shows two fixed charge schedules that would recover the 2019 SDG&E residential revenue requirements had volumetric rates been set to SMC. The flat teal line shows the monthly fixed charge for all households if charges are uniform. The red step line shows an income-based fixed charge that mimics the progressivity of the sales tax. The bottom panel shows the distribution of the change in annual bills, holding household electricity consumption fixed, for SDG&E households in each income category. This change is induced by moving households from the status quo to an IBFC pegged to the progressivity of the state sales tax. A negative number indicates that bills would go down under an IBFC. The percentages below the income categories indicate the share of households falling into each category.

The other direction is to advocate for an electricity rate structure which includes a traditional fixed charge that is not income based, paired with a reform of the income tax system (or other state programs) designed to offset any cost shift onto lower-income households. Put another way, introducing a uniform fixed charge would shift burdens onto lower-income households as compared to the status quo, but the state legislature could simultaneously tweak the income tax system to counteract that cost shift. This has the obvious advantage of not requiring the new institutions or infrastructure required to support an IBFC. This idea has merit, but as well it has limitations. It would likely be difficult to credibly pair rate reforms from the CPUC with income tax changes from the legislature and governor.

Another important drawback of a uniform fixed charge combined with income tax changes is that, while such a reform could be designed to ensure a neutral (or progressive) impact on average across households, it will still create winners and losers along the income distribution. This is inevitable given both the complexities of how households interact with the income tax system and the large variation in residual cost burdens documented here. Recent research has demonstrated the extreme difficulty of designing policies that compensate all households in the presence of consumption variability.[37,38] In contrast, an income-based fixed charge that includes no fixed charge for households below a certain income threshold would likely result in a higher share of households below that threshold being made better off by the reform, assuming that they can be correctly identified.

4.4 Minimum bills would raise little revenue and would be very regressive

Minimal bills are sometimes suggested as an alternative rate reform to increase revenues and address funding needs. Careful calculations of the revenues that minimum bills would bring in, however, show that they would not meaningfully address the funds needed to cover the residual cost burden. At the same time, minimum bills create inefficient incentives to increase consumption for those with low usage.

If a utility has a minimum bill, then customers pay the higher of two amounts: the minimum, or the amount they would be billed given the other components of the rate structure. Thus, if a utility had a $30 per month minimum, anyone with sufficient consumption to be charged more than $30 would be unaffected, but a customer who otherwise would have spent only $20 in a particular month would see their bill increase by $10.

Minimum bills are sometimes conflated with fixed charges because both imply that any given bill will be at least as large as some number. As pointed out by Borenstein (2016),[39] however, a minimum bill is in fact a fixed charge combined with a zero volumetric price for some initial range of consumption.[40] This creates inefficient incentives, because customers consuming below the "breakeven quantity" can raise their consumption at no cost, whereas society still bears the social marginal cost for each additional kWh. At the same time, a minimum bill raises no additional revenue from any customer who would have consumed enough to exceed the minimum amount anyway. The minimum bill levels that have generally been suggested—$30-$60 per month—would have no effect on the great majority of customer bills, while giving low-usage customers distorted incentives to increase their consumption up to the minimum bill level.

The equity impact of a minimum bill depends on which customers tend to consume a small enough quantity from the grid that their monthly bill would otherwise be below the minimum bill. Normally, one might think that this is disproportionately lower-income households, but it could also apply to household that have installed large solar systems, which displace most of their consumption from the grid.

To examine this possibility, the authors used the 2019 utility billing data to calculate the impact of adopting a minimum bill of either $30 or $60 per month ($1 or $2 per bill-day). To do so, they identified all bills that were below the minimum and counted the additional revenue implied if the minimum were in effect, but household consumption was unchanged. By assuming households below the minimum do not increase their consumption, despite the fact that marginal consumption would be free, the calculation overstates the increased net revenue to the utility. To the extent that household did increase their consumption up to the minimum bill, that would raise no additional revenue but would impose additional costs to cover supply of that extra electricity.

The calculation includes customers with rooftop solar and customers on CARE. Excluding either group would lower the revenue further. Table 2 shows that even with these generous assumptions, a $30 per month minimum bill raises very little revenue and even a $60 per month minimum raises modest sums compared to the overall residential revenue or the residual cost burden.

The authors also use the billing data to examine the distributional implications of raising this amount of revenue via minimum bills. Table 3 shows how much of each dollar of extra revenue comes from households in different income categories. For instance, for PG&E,

37 Sallee, James. 2019. "Pigou Creates Losers: On the Implausibility of Achieving Pareto Improvements from Efficiency-Enhancing Policies." Energy Institute at Haas Working Paper 302R.

38 Cronin, Julie Anne, Don Fullerton, and Steve Sexton. 2019. "Vertical and Horizontal Redistributions from a Carbon Tax and Rebate." Journal of the Association of Environmental and Resource Economists, 6(S1): S169–S208.

39 Borenstein, Severin. 2016. "The economics of fixed cost recovery by utilities." The Electricity Journal, 29(7): 5–12.

40 For instance, a minimum bill of $30 per month for a utility that charges $0.20 per kWh means that the first 150 kWh per month have no effect on a customer's bill, that is, effectively they have a zero volumetric price.

53 percent of the additional revenue would come from households in the bottom three income categories, which constitute only 46 percent of all households. By contrast, the 26 percent of all households that are in the top two income categories would contribute only 20 percent of the additional revenue. In practice, a minimum bill of $60 per month would be a far more regressive approach to raising funds for the residual cost burden than even the current rate design.[41] The results are similar in the other service territories.

4.4.1 Grid defection

A concern raised in response to proposals for large fixed charges—whether they are income based, uniform, or applied only to households with behind-the-meter generation—is that they could lead customers to disconnect from the grid entirely in order to avoid paying the monthly charges.

This phenomenon, commonly referred to as "grid defection," is most relevant for solar customers, who can potentially move off the grid by having a solar system adequate to power their home when combined with a battery storage system, and possibly a backup fossil-fueled generator. For customers with large solar-plus-storage systems, a connection to the grid functions as insurance against a streak of low solar production that exhausts batteries. The implicit insurance premium paid by such a household for the grid backup is the fixed charges paid.

Socially-inefficient grid defection occurs when the incremental social cost (including pollution externalities) of providing electricity to a customer from the grid, for a given level of reliability, is lower than the cost of doing so disconnected from the grid, yet the customer still chooses to disconnect in order to lower their private cost. This could occur if a large fixed charge caused the retail bill to be well above the incremental social cost of serving the customer, as the authors' analysis of the residual revenue requirement suggests would be the case in California. In fact, given the very low social marginal cost of providing clean power from the grid, virtually any grid defection by a household that has had a distribution line connection is likely to be inefficient.

It is important to recognize that the concern with grid defection under income-based fixed charges would be with the most affluent households, those facing the highest fixed charges. These are also the customers most likely to install large solar systems with batteries. And they also are likely to be willing to pay the most to avoid unreliable electricity supply. With the exception of small numbers of enthusiasts willing to devote a great deal of focus to balancing their energy production and usage, these households seem unlikely to be willing to endure outages or the need to monitor consumption closely in order to avoid running out of power.

At this point, it remains expensive to install sufficient battery storage to reach reliability levels comparable with the grid, as Gorman, Callaway and Jarvis (2020) demonstrate.[42]

TABLE 2 Revenue Increases Under Minimum Bills by Utility (2019)

	MINIMUM BILL AMOUNT	
IOU	$30/month	$60/month
PG&E	2%	9%
SCE	5%	18%
SDG&E	4%	15%

TABLE 3 Distribution of Revenue Increase by Household Income for $60/Month Minimum Bill (2019)

	INCOME CATEGORY ($000 PER YEAR)						
IOU	[0,25)	[25,50)	[50,75)	[75,100)	[100,150)	[150,200)	200+
PG&E	20%	18%	15%	11%	15%	8%	12%
SCE	23%	22%	16%	12%	14%	6%	6%
SDG&E	17%	20%	17%	12%	16%	8%	9%

41 The same is true for a minimum bill of $30 per month, but the revenue impact of such a low minimum bill is minuscule, so we focus on a higher figure.

42 Gorman, Will, Duncan S Callaway, and Stephen Jarvis. 2020. "Should I Stay Or Should I Go? The importance of electricity rate design for household defection from the power grid." Applied Energy, 262(1): 114494.

To take a case very favorable to grid defection, consider a relatively wealthy household that has fairly high usage, but has sized its solar system to exactly match annual consumption, so it currently pays virtually nothing to the utility for electricity.[43] Grid defection for this household would avoid the fixed charge under the IBFC proposed above, a savings of approximately $1,200 to $1,700 per year for a household in the top income category, depending on the utility. Gorman, Callaway and Jarvis (2020) find that the vast majority of such households would need to invest in over 100 kWh of storage to reach a level of reliability comparable to the grid. At today's prices of distributed battery storage with installation, such as the Tesla Powerwall, that would cost at least 20 times more than the annual savings on the fixed charge. Of course, if distributed storage costs were to decline drastically, such inefficient grid defection could become a serious problem for a system covering its residual revenue requirement through high volumetric prices.

A more serious concern in the short run would be wealthy households that install a large solar system, moderate battery capacity, and a natural gas-powered generator with significant capacity.[44] If such customers were willing, and allowed, to run the generator whenever the solar plus storage came up short, they may be able to achieve close to the same reliability as they could with grid connection. The question is whether such households would find the large capital investment, attention needed to manage one's own electricity needs, and local pollution from the gas-fire generator worth it to avoid the fixed charge. As of today, despite some research arguing that grid defection has been economic for many years, there is little evidence it has taken hold yet.[45] Still, that could change as technology improves and the financial incentives for defection increase, making income-based fixed charges relatively less viable compared to covering residual costs through the state budget.

43 The household would still be responsible for the non-bypassable charge (2-3 cents/kWh) on its gross consumption of electricity from the grid.

44 The capital and installation costs of such a generator that can meet the full load of a relatively large home seems to be $10,000-$20,000. See: https://www.bobvila.com/articles/whole-house-generator-cost/.

45 Kantamneni, Abhilash, Richelle Winkler, Lucia Gauchia, and Joshua M Pearce. 2016. "Emerging economic viability of grid defection in a northern climate using solar hybrid systems." Energy Policy, 95: 378–389.

CONCLUSION

There is a fundamental tension between the way that California pays for electricity and its stated goals of achieving decarbonization while fostering equity and ensuring that energy is affordable for all. Escalating costs, which are both caused by climate change (e.g., wildfire mitigation) and required to combat it (e.g., system upgrades to spur electrification), are exacerbating these problems and are bringing the state to a point of crisis. As such, California is at a point of reckoning, requiring a substantial reconsideration of how electric utility costs are recovered, even if it is costly and difficult. Identifying ways to contain and reduce these costs is another important policy objective, but not one that is addressed in this report.

The good news is that there are feasible rate reforms that can simultaneously improve equity while eliminating headwinds against decarbonization by lowering the marginal price of electricity faced by households in the state. These include moving costs onto the general state budget and instituting income-based fixed charges.

To help understand the strengths and weaknesses of potential reforms, this report provided a detailed look at who bears the burden of residual cost recovery under the status quo and under some specific alternatives. As well, it quantified the magnitude of the barriers to electrification implied by the current regime.

The authors showed that, while richer households do pay more per year towards residual cost recovery, the effective electricity tax imposed to cover those costs is more regressive than a sales or income tax. Moreover, there is a great deal of variation across households in the burdens created by the effective electricity tax, depending on their consumption, participation in CARE, and adoption of rooftop solar.

The current pricing system is also creating substantial barriers to electrification, slowing progress on electrification in the residential sector. The authors estimate that current prices create an average excess cost burden of roughly $600 per year on both electric vehicle ownership and on the adoption of electric space heating. This excess cost slows adoption of cleaner technologies, and this impediment to decarbonization will keep growing as costs rise if the rate system is not reformed.

The wide variation in residual cost burdens under the current regime implies that any major reform will create winners and losers. Even so, the authors show that it is straightforward, conceptually, to design a system of income-based fixed charges—designed to be approximately as progressive as state's sales tax—that shifts the burden of cost recovery systematically towards higher-income households while simultaneously lowering rates so as to foster electrification. Such a reform requires administrative and legal actions, but the authors believe it is time for the state to seriously consider this option, as well as the more administratively straightforward option of moving costs directly on to the state budget.