Retail Pricing in Colombia to Support the Efficient Deployment of Distributed Generation and Electric Vehicles

FINAL DRAFT

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Abstract

Electricity tariff reforms will be an essential part of the clean energy transition. Existing tariffs rely on average cost pricing and often set a price per unit that exceeds marginal cost. The higher price encourages over-adoption of residential solar panels and under-adoption of electric alternatives to fossil fuels. However, an efficient tariff based on fixed charges and marginal cost pricing may harm low-income households. Households with low demand for electricity may prefer to disconnect from the grid rather than pay an equal share of fixed costs. We propose an alternative methodology for setting fixed charges based on the predicted willingness-to-pay of each household. Using household data from Colombia, we show the fiscal burden and economic inefficiency of the existing tariffs. We then show how our new tariff methodology could improve economic efficiency, create incentives for the adoption of clean energy technologies, while still leaving low-income households better off.

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Rapid technological change has created a challenge for the traditional approach to public utility pricing. In most of the world, public utility tariffs use average cost pricing, in which the per-unit price combines fixed, capital, and variable costs of providing the service. An average cost tariff means that the price paid by a customer for an additional unit of consumption can far exceed its marginal cost. For electricity, this creates an incentive for customers to install solar panels. With average cost pricing, residential solar panels may be privately optimal even though the average cost of energy is greater than the average cost of energy from a large-scale, grid-connected solar generation unit. Conversely, average cost pricing creates a disincentive for customers to use electricity for applications in which it can replace fossil fuels. With an electricity price that is too high, customers will not switch to using electricity for cooking or transportation—even though the social cost of electricity may be much lower than the social cost of fossil fuels.

Reforming the electricity price structure is an important step to create the conditions for the clean energy transition. The basic principles of an optimal tariff have been well-known since at least Hotelling (1938). Consumers should pay the marginal cost of supply at their level of consumption, including the external costs of local and global pollutants. The remaining costs of providing the electricity service would be covered by a fixed charge that does not depend on the consumption quantity.

Particularly in developing countries, a two-part tariff for electricity with a uniform fixed charge is infeasible. Many households have low willingness-to-pay for electricity and low consumption. Setting the same fixed charge for all consumers may mean that the consumer surplus from electricity consumption is less than the fixed charge, in which case the consumer would prefer to disconnect from the grid. Moreover, for distributional reasons, it may be seen as inequitable to set the same fixed charge for a high-income household with high electricity consumption as for a low-income household with low electricity consumption. There is also an issue of political feasibility: given the existing tariff structure in many countries, transitioning to an efficient tariff with identical fixed charges would leave most households worse off.

We propose an alternative methodology for setting tariffs that avoids these downsides of a traditional two-part tariff. As before, households pay a per-unit price equal to the marginal cost. However, instead of the same fixed charge for all households, the fixed charge would be set based on a prediction of the willingness-to-pay of each household. Those with the lowest predicted willingness-to-pay would pay a low, zero, or even negative fixed charge. Because the fixed charge does not depend on realized consumption, the differences across households will not distort consumption decisions. Instead, the choice of how much electricity to consume, or the decisions to invest in solar panels or electric cars, will depend only on the marginal cost.

We illustrate the proposed tariff regime using household-level data for Colombia. The existing tariff in Colombia has an increasing block structure, with the subsidy on the first tier depending on the socioeconomic classification of the neighborhood. The first-tier subsidies are financed by contributions from the households in the highest two categories, contributions from commercial users, and transfers from the central government. We show that government transfers to support this tariff regime have been increasing over time, in part because of a substantial increase in the number of households on the highest subsidy tier.

The current electricity tariffs in Colombia introduce considerable distortions into decisions about electricity consumption. We use hourly data from the wholesale electricity market to calculate the marginal cost of supplying electricity to a household. Some households pay less than two-thirds of the marginal cost. Other households pay more than three times the marginal cost. These price distortions lead to electricity consumption that is inefficiently high or inefficiently low. On average, the deadweight loss associated with these distortions is about US$1 per household per month.

The tariff structure also affects decisions to adopt new energy technologies. We focus on residential adoption of rooftop solar and electric vehicles. Households who pay an electricity price that is far above marginal cost may have an incentive to install solar panels, even if the value of electricity produced by those panels is less than the installation cost. Those same households paying a high electricity price will be less likely to buy and charge an electric vehicle.

Under our proposed tariff alternative, the price per unit would be the same for every household and equal to social marginal cost. We calculate the revenue requirement per household-month for each electricity distribution company. On average, the required fixed charge would be slightly less than US$5 per household per month. Switching from the current tariff to a new tariff based on marginal cost pricing and an equal fixed charge would leave households in the bottom half of the income distribution worse off on average.

Instead, we show the distributional effects of alternative policies for targetting the fixed charges. Our preferred targeting mechanism uses the predicted squared consumption of each household, based on a regression of the square of household-level electricity consumption on dwelling characteristics. Under the assumption of linear demand, the square of consumption is proportional to the consumer surplus from electricity consumption. The fixed charge for each household is set based on its share of the sum of predicted squared consumption for all households served by the electric utility. The targeting performance of this mechanism would be further enhanced if it were combined with the existing means-testing program for government health insurance subsidies in Colombia.

In contrast to the tariff that sets the same fixed charge for everyone, our proposed methodology (when combined with the existing means-testing program) would leave households in every decile better off on average than under the existing tariff. The share of households who would find it optimal to disconnect from the grid would be less than half the share for the equal-fixed-charge tariff. Because all households will pay the marginal cost for their consumption, all households would face economically efficient incentives for their short and long-term consumption decisions. In particular, adoption of new supply technologies (such as residential solar panels) and adoption of new demand technologies (such as electric stoves or electric vehicles) would not be distorted by the tariff structure.

Our results show that it is possible to transition to an efficient electricity tariff while still protecting low-income households from bill shock. We note that the methodology based on predicted squared consumption is feasible to implement given data that is already available to electricity retailers in Colombia. Our prediction uses dwelling characteristics contained in the national cadastral database which is linked to the utility billing identifiers. This information is already used to determine the stratification and tariff level of each household. What is most appealing about our methodology is that it avoids the intermediate step of the coarse classification of households into six strata. The lack of granularity of the strata means the loss of potentially valuable information in the cadastral data about each household's willingness to pay for electricity. Using dwelling data to predict the square of electricity consumption, then using the predicted square of consumption to set fixed charges, allows for finer differentiation across different types of households.

The remainder of the paper is organized as follows. Section 1 describes the regulatory environment in Colombia and the evolution of the existing tariff regime. Section 2 details our calculation of the marginal cost of electricity and the short-term distortions associated with the existing tariffs. Section 3 provides our analysis of the incentives for installing rooftop solar and buying an electric vehicle. Section 4 outlines our proposal for an optimal tariff, including the alternative methodologies for allocating fixed costs. Section 5 concludes.

1 Residential Electricity Prices in Colombia

The primary regulator in the Colombian energy sector is the Energy and Gas Regulatory Commission (CREG, short for its Spanish name: *Comisión de Regulación de Energía y Gas*). Its role is to set the rules governing the behavior of market participants to ensure an economically efficient provision of electricity and gas. CREG acts based on the policies set by the Ministry of Mines and Energy.

For households and other small consumers, CREG determines the regulated tariff for electricity. The tariff consists of a variable charge, with no fixed charge component. The base tariff is the sum of six components: generation (based on the wholesale market procurement costs for the retailer), transmission, distribution, retailing, allowed losses, and transmission restrictions. Distribution and transmission charges are set based on rate-of-return regulation.

There is considerable variation across retailers in the regulated base tariff, mostly reflecting differences in the distribution and retailing costs (Figure 1). As of June 2017, the cheapest distribution and retailing firm was Emcartago, with a base retail price of about 12 US cents per kWh, and the most expensive was Emevasi, with a base retail price of about 20 US cents per kWh.

Colombia has a targeted program of quantity-based electricity subsidies based on a geographic classification of neighborhoods into six socioeconomic strata (*estratos*). Households in Strata 1, 2, and 3 receive a subsidy of approximately 50–60 percent, 40–50 percent, and 15 percent, respectively, for an initial block of consumption and then pay the regulated base price for all additional consumption. There is variation across the distribution firms and across months in the level of the subsidies applied to the Strata 1 and 2 consumption (Figure 2).

Households in Strata 5 and 6 and commercial users pay 120 percent of the regulated base price for their entire consumption, with the additional 20 percent being used as a contribution to the subsidy program. Households in Strata 4 pay the base price for their entire consumption. There are relatively few households contributing to the subsidy program and these are concentrated among the distribution firms serving the largest urban areas (Figure 3).

The stratification procedure is run by municipal authorities, following guidelines set by DANE, the national statistical agency. Over the past 15 years, there has been considerable growth in the number of subsidized households in Strata 1 and 2 (Figure 4). The total number of customers in these two strata grew from about 5 million in 2004 to more than 9 million in 2018. The number of contributing households in Strata 5 and 6 has not grown as quickly.

The increase in the number of subsidized households has been matched by an increase in the quantity of subsidized consumption (Figure 5). In contrast, the aggregate consumption in Strata 5 and 6 has stayed fairly constant since 2004, reflecting a decline in the per customer consumption of these households. This decline may have been caused by a combination of a change in customer composition and by improvements in energy efficiency for high-income households. As of 2019, the penetration of residential rooftop solar is negligible in Colombia, so this is unlikely to have contributed to the reduction in aggregate consumption by high-income households.

For all except the largest urban electricity distributors, the cross-subsidy from high-income households and commercial users does not cover the cost of the subsidy transfers to the households in Strata 1 to 3. The subsidy deficit for each utility is covered by the redistribution fund known as the Solidarity Fund for Subsidies and Income Distribution (FSSRI, for its initials in Spanish: *Fondo De Solidaridad Para Subsidios y Redistribución de Ingreso*). Utilities with an contribution surplus pay the extra revenue into FSSRI and utilities with a contribution deficit receive the difference from FSSRI. The overall fund runs at a loss and this loss is covered by a budget allocation from the central government.

The trends described above have increased the loss of the redistribution fund and increased the required government transfer. There are many more subsidized households, the consumption of these households has increased, and the subsidy percentages have increased. On the revenue side, the consumption by residential users who are paying a contribution has stayed fairly constant. A policy change also eliminated the contribution requirement for some types of non-residential customers. Overall, these changes have meant that the program deficit funded by the central government has increased over time to more than 0.75 percent of total government expenditure (Figure 6).

There are two main challenges for the current electricity tariff regime in Colombia. First, the tariffs create a wedge between the price and the marginal cost of electicity consumption. Most households pay a price that exceeds marginal cost, while some households in Stratum 1 and 2 pay less than marginal cost. Second, the tariff structure places ever-greater burdens on the Colombian government to meet the shortfall between the payments to electricity suppliers and the revenues received from households.

2 Short-run Implications of Inefficient Retail Pricing in Colombia

An **efficient** price schedule for electricity is one in which the amount that the consumer pays for one additional unit of consumption (the marginal price) is equal to the cost of supplying that additional unit of consumption (the marginal cost). If marginal prices are higher or lower than marginal costs, then there will be a distortion in the consumption decision. In particular, if the marginal price exceeds the marginal cost, then the household will choose to consume too little electricity. Society as a whole will be worse off, because of the lost opportunity for beneficial electricity consumption.

2.1 Marginal Price of Electricity

We use data from the National Household Budget Survey that was conducted in Colombia between July 11, 2016 and July 9, 2017 (Departamento Administrativo Nacional de Estadística, 2018). For each household, the survey provides information on the municipality where they live and the stratum used for their electricity tariff. This makes it possible to match the household data to the electricity distribution company and then to the electricity tariff that households faced in the month before the survey. In addition, survey respondents report the amount of their most recent electricity bill. Given the tariff information, this makes it possible to impute their electricity consumption for the month in kilowatt-hours.

We illustrate this imputation procedure with an example. In the survey data, suppose we observe a Stratum 2 household living in Bogotá with a reported electricity expenditure of 50,000 pesos in March 2017. We match the municipality (Bogotá) to the electricity supplier (Codensa) and use the tariff sheets published by Codensa for March 2017.[1] The tariff for Stratum 2 households was 245 pesos/kWh for the first 130 kWh of consumption per month and 454 pesos/kWh for all subsequent consumption. A Stratum 2 household consuming the entire first tier would have a bill of 31,850 pesos (245×130). So the survey household had 18,150 pesos of consumption on the second tier, or 40 kWh (18,150/454). The imputed monthly consumption for the survey household is 170 kWh (130 + 40).

Figure 7 shows the distribution of monthly household electricity consumption in Colombia. We drop households with very low (below 10 kWh/month) or very high (above 2000 kWh/month) imputed consumption. Most households consume less than 250

[1] The tariff data for Codensa was obtained from `https://www.enel.com.co/es/personas/tarifas-energia-enel-codensa.html`.

kWh/month. We drop observations for dwelling types other than houses or apartments—most of these are rooms in boarding houses that are unlikely to have individual electricity meters.

For the households in Strata 4 to 6, the marginal price that they pay for electricity can be read directly from the tariff schedule. Households in Strata 1 to 3 face a nonlinear tariff and so their marginal price will depend on their consumption. We combine the imputed consumption from the survey with the tariff schedules to identify the marginal price the household faces. If the household has consumption exceeding the first tier threshold, then their marginal price is the second tier price, which is equal to the base retail price. Otherwise, if the household has consumption below the first tier threshold, their marginal price is the subsidized price for the first tier.

The distribution of marginal prices, in US cents per kWh, is shown in Figure 8.[2] The lowest marginal price observed in the data is 5.2 U.S. cents per kWh. The highest marginal price in the data is more than four times higher: 22.8 cents per kWh. For comparison, the average residential retail price in the United States during 2017 was 12.9 cents per kWh.[3] The lowest price was in Washington state: 9.7 cents per kWh. Hawaii was the only state with an average electricity price exceeding the maximum marginal price that we observe in our Colombian household data.

2.2 Marginal Cost of Electricity

Whenever a household turns on a light, boils a kettle, or plugs in an electric heater, the increase in their electricity consumption is instantly matched by an increase in the output of an electricity generation plant somewhere on the grid. The higher output does not necessarily come from the plant that is closest to the household's location. The marginal cost of satisfying this increase in consumption is the cost of generating one extra unit of electricity and delivering it through the grid to the household.

Like all short-term wholesale electricity markets, Colombia runs an auction in which generators compete to supply electricity by offering in their generation units. In an idealized environment with no transmission constraints and no other operating constraints,

[2]We use the same exchange rate to convert from Colombian pesos to U.S. dollars throughout the paper: 2954 Colombian pesos per dollar. This was the mean exchange rate over the period covered by the household survey. The minimum and maximum values for the exchange rate were 2,838 and 3,188 pesos per dollar. Exchange rate data are from the Colombian central bank, Banco de la República: `http://www.banrep.gov.co/es/tasa-cambio-del-peso-colombiano-trm`.

[3]`https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf`.

the system operator could stack up the generator offers in order of increasing price, choosing to run the cheapest plants first, until the cumulative output equals total electricity demand. The price offered for the last plant that is turned on would be exactly equal to the marginal cost of producing one more unit of electricity. The price offer of this plant is the system price.

Unfortunately, this process is complicated by real-world constraints on the operation of the transmission grid. In particular, each transmission line has a capacity rating that determines the maximum quantity of electricity that it can carry. These ratings place additional constraints on the optimization problem solved by the system operator. For example, suppose there is a high-cost generation plant located in a region that has limited transmission capacity to the rest of the grid. During hours in which demand in the region exceeds the capacity of the transmission line into the region, the system operator will need to use the high-cost plant. As a result, the marginal cost of supplying an extra unit in the region will be the marginal cost of the high-cost plant. This could be much higher than the price for other parts of the country.

Every system operator faces the same problem of transmission constraints and is required to account for these constraints when solving for the optimal allocation of generation across plants. However, markets differ in the extent to which they explicitly report these constraints and account for them in the prices that generators receive and the prices that retailers pay. For a nodal price market, every location on the transmission grid has an associated hourly price. This price is defined as the marginal cost of supplying one extra MWh of demand at that location in that hour, accounting for all transmission constraints, transmission losses, and other operating constraints. These nodal prices make it straightforward to determine the marginal cost of meeting an increase in electricity demand by a household.

Colombia does not use nodal prices in its wholesale electricity market. Instead, the system operator solves two optimization problems. First, it calculates the optimal generation under the assumption of no transmission constraints. This calculation determines the system price and the "ideal" generation for each plant. Figures 9 and 10 summarize the average pattern of system prices, over hours in the day and over weeks in the year, that come out of this algorithm, expressed in U.S. dollars per MWh. Prices are highest in the peak demand hours in the early evening. Prices fluctuated over the period covered by our household survey, but generally trended down, falling below US$25 per MWh by the end of May 2017.

After computing the system price and ideal generation, the system operator calculates the optimal generation mix accounting for the transmission constraints. This determines the actual generation allocated to each plant. Generators receive the system price for their output. However, if a generator is required to produce more or less than its ideal generation, it receives a reconciliation payment for the difference. Positive reconciliation payments, for actual generation in excess of ideal generation, are calculated based on the fuel costs of the plant.

We use data from the system operator XM on the hourly system price as the starting point for calculating the marginal cost of electricity. The true marginal cost will vary by location, depending on the requirement for additional generation plants in a region to be turned on as a result of the transmission constraints. We do not have information on the optimal dispatch algorithm that accounts for these constraints. Nor do we have information on the value of reconciliation payments made to each generator. These are not published by the system operator because they would reveal confidential information about fuel prices.

Instead, we estimate the average hourly positive reconciliation payments. For each generator with output exceeding its ideal generation, we multiply the excess generation by the difference between the plant's offer price in the wholesale market auction and the system price. We sum this amount for all plants and divide by aggregate generation. Formally, the calculation of average reconciliation payments is:

$$rec_t = \frac{\sum_{j \in J} \max(0, q_{jt}^{r+}(p_{jt} - P_t)}{\sum_{j \in J} q_{jt}}$$

where j indexes generation plants, q_{jt} is the output of plant j in hour t, p_{jt} is the offer price of plant j in hour t, P_t is the system price in hour t, and q_j^{r+} is the positive reconciliation quantity for plant j in hour t.

The sum of the system price and the average positive reconciliation payment is our estimate of the marginal cost of generating an additional kWh of electricity. However, the marginal cost of **consuming** an additional kWh will be higher than this due to transmission and distribution losses. These losses are an unavoidable consequence of resistance in the cables used to transmit electricity, causing some of the electricity to be converted to heat. If losses are 10%, then for a household to consume 1 kWh, the generation plants will need to produce $1/(1 - 0.1) = 1.11$ kWh of electricity. In that case, if the marginal cost of generating 1 kWh is 100 pesos, the marginal cost of consuming 1 kWh will be 111 pesos.

Resistance (and hence losses) increase with the square of the amount of electricity flowing through a wire. This means that losses will be greater during peak demand hours when electricity flows are higher. For determining the marginal cost of electricity consumption, the marginal losses are what is relevant, not the average rate of losses during the year.

We have hourly data from the system operator on the losses that are allocated to retailers as part of the financial settlement process. In theory, the transmission losses are the difference between the electricity that is injected into the grid at the generation plants and the electricity that is withdrawn from the grid by the distribution networks. However, the aggregate allocated losses are uncorrelated with system demand. This suggests that they are based on an administrative formula rather than a physical measurement. We use the average hourly allocated losses (1.5 percent of demand) as a proxy for the marginal transmission losses.

The losses from sending electricity through the distribution network to the final user are typically larger than the transmission losses. This is because the distribution network carries electricity at a lower voltage than the transmission network, and the electrical resistance of a wire is higher at lower voltages. Unfortunately, we do not have data on the hourly quantity of distribution losses. These are very difficult to measure because they would require hourly information on the quantity of electricity being injected into the distribution network as well as the quantity of electricity being consumed by each user. Such a calculation would only be possible if all customers in the network had hourly meters.

Instead, distribution networks report information on their average losses over a year. The reported losses are the difference between the electricity entering the grid and the electricity that is metered and billed to customers. The average reported losses include both technical and non-technical losses. The technical losses are the physical losses from electricity flowing through a wire, described above. The non-technical losses include unmetered withdrawals of electricity by final users—for example, by households in informal settlements with unofficial connections to the grid. It is possible to use engineering models of the distribution network to estimate the technical losses, leaving the non-technical losses as a residual. However, it is impossible to separately measure the two types of losses.

This distinction between technical and non-technical losses is important for two reasons. From the perspective of social welfare, the technical losses represent a cost to society, because the electricity is being generated but provides no consumption benefit. However, the non-technical losses are not a cost to society—they represent a transfers of benefits from the distribution company to the unmetered users. The electricity still provides consumption benefits, even if it is not paid for.

The second reason we should distinguish the two types of losses is that for calculating the marginal cost of electricity, only the marginal technical losses are relevant. For a household using an extra kWh, some additional losses will be created within the distribution network. But there will be no effect on the consumption of neighboring households with informal connections to the distribution grid.

We therefore face two challenges for calculating marginal distribution losses. The available data is annual, not hourly, so it informs us about average not marginal losses. Furthermore, the reported losses include both technical and non-technical losses, but we only want to include technical losses in the calculation.

Instead, we use recent estimates from Borenstein and Bushnell (2018) on the marginal losses in the distribution networks in the United States. They estimate a distribution of marginal losses with a mean of 8.87% and a standard deviation of 1.83%. We apply these parameters to estimate marginal losses in Colombia, allocating losses to hours using the system load shape. Specifically, we rank every hour in our sample in order of total electricity demand. Given the percentile rank of each hour, we use the inverse cumulative normal distribution function with the Borenstein and Bushnell (2018) parameters to calculate the corresponding marginal losses. We truncate the estimates at the minimum and maximum of the estimated losses in their paper.

Figure 11 shows the distribution of hourly marginal losses in the transmission and distribution networks in Colombia. The mean marginal loss over the sample is 10.93%. However, for the highest demand hours, marginal losses exceed 15%. These losses have an important effect on the marginal cost of electricity consumption.

The final component of the marginal cost of consuming electricity is the external cost associated with the emissions from the generation plants that increase their output in response to an increase in demand. There are many studies by economists estimating these marginal emissions effects for electricity markets in the United States (Cullen, 2013; Novan, 2015; Callaway, Fowlie and McCormick, 2018). The methodology is similar in all cases. Output (or emissions) from individual plants is regressed on total system output. The results provide econometric estimates of the incremental production from each plant in response to higher demand.

Unfortunately, it is difficult to apply this methodology to estimate marginal emissions effects in Colombia. Approximately two thirds of electricity generation in Colombia is hydroelectric. One advantage of hydro plants is that they can change their output very quickly. As a result, in hydro-dominated systems, variation in demand during the day is typically met by changing the hydro output. Figure 12 shows the average within-day variation in output for different generation technologies in Colombia, between June 2016 and May 2017. The values are scaled so that the mean output for each technology is 1. Hydro is by far the largest source of energy in market. It is also the technology that exhibits the greatest operating variation across the day. In the middle of the night, hydro output is more than one third lower than output during the evening peak. The fuel with the least variation is coal, reflecting the longer time necessary to increase or decrease generation from coal-fired plants.

These results imply that instantaneous increases in electricity demand are met by increasing output from hydro plants. This might suggest that there are zero emissions associated with marginal increases in demand, because hydro does not produce emissions. This is incorrect. There is a constraint on the total amount of water available to produce hydroelectricity. All else being equal, producing an extra kWh from hydro today will mean that there is less water available in the reservoirs to produce electricity tomorrow. If the constraint on the total amount of water available is binding, so that all available water is used during the year, then a marginal increase in demand will have to be met from fossil fuel generation plants.

The complication for the analysis is that there is no easy way to match the increase in demand to the subsequent increase in fossil fuel generation. Castro (forthcoming) studies the shifting of emissions across hours of the day through the reallocation of hydro production in the Californian electricity market. However, for the case of Colombia, it is possible that there is a time gap of six months or more between the demand shock and the resulting thermal generation. Because we do not know when the additional generation occurs, we cannot identify the type of generation: coal or fuel oil or natural gas. This matters because these fuels have very different emissions profiles.

Instead, we calculate the average emissions per kWh from thermal generation in Colombia for the period of the study. We use daily data on the fuel consumption of each generation plant, measured in millions of BTU. We convert the fuel consumption to carbon dioxide emissions using standard emissions coefficients (U.S. Energy Information Administration, 2016). Dividing the total carbon dioxide output by the total thermal generation for the period gives an average emissions factor of 0.61 tonnes of carbon dioxide per MWh of electricity generated. We convert this emissions factor to a monetary value using a social cost of carbon of US$33.60 per ton (Nordhaus, 2018). This calculation gives a carbon price component for our marginal cost calculation of 2.1 US cents per kWh.

The above discussion assumes that there is a binding constraint on hydro availability, so that any increase in demand is met by fossil fuel generation. If there is excess water available that is not currently used for generating electricity, then an increase in demand could be met by higher hydro generation. This would imply that the external cost component of the marginal cost of electricity consumption is zero. We note that hydro spill (the release of water from hydro reservoirs without generating electricity) was non-zero during the period, suggesting that the hydro constraint was non-binding. However, more information would be needed on the reasons for spilling the water, to understand whether it could have been used to offset an increase in electricity demand.

The only external cost from electricity generation that we consider is the cost of carbon dioxide emissions—a contributor to global climate change. Other pollutants from fossil fuel plants, including sulfur dioxide, nitrogen oxides, and particulate matter, create local air pollution that may harm the surrounding population. Several studies by economists in the United States quantify the marginal emissions of these other pollutants and use models of how they move through the atmosphere to identify the affected areas (Muller and Mendelsohn, 2009; Holland et al., 2016). Unfortunately, data on power plant emissions is not collected in Colombia, making it difficult to estimate the marginal emissions effects.

Combining the four components of the cost of electricity consumption, we find that the mean marginal cost over the year of our study is 8.4 US cents per kWh: 4.8 cents for the system price of generation, 0.6 cents for the positive reconciliation payments, 2.1 cents for the carbon price, and 0.9 cents for the marginal losses. On average, this is the efficient price that households in Colombia should be charged for their electricity consumption. Charging a price that is too high or too low will create distortions in household consumption decisions.

However, there is considerable variation in the marginal cost over days of the year and even hours of the day. Figure 13 shows the mean composition of marginal costs across hours of the day. The marginal cost of consuming electricity is lowest at 3:00 AM and highest at 7:00 PM. Most of this variation reflect differences in marginal generation costs due to the pattern of electricity demand across the day. By assumption, carbon costs are the same in every hour, and the reconciliation costs are fairly stable across the day. Interestingly, differences in marginal losses exacerbate the intraday variation in marginal costs. Marginal losses are higher in high-demand hours, exactly when generation costs are also high.

The marginal costs also differ across months of the year, as shown in Figure 14. The graph shows the weighted mean of the components of marginal cost across all the hours in each month. Marginal cost was highest in August 2016 (nearly 11 cents per kWh) and lowest in May 2017 (less than 6 cents per kWh). These differences are mostly due to changes in generation costs over the study period, arising from changes in the opportunity cost of using water for hydro generation and changes in the price of fossil fuels for thermal generation.

Figures 13 and 14 illustrate the variation in marginal costs across hours in the year. The optimal tariff structure would have a time-varying electricity price, set each hour to reflect the real-time marginal cost. The lack of real-time meters in Colombia makes it impossible to implement such a tariff. We instead consider a tariff that changes each month based on the marginal costs in Figure 14, but that does not vary for hours within the month. Implementing such a tariff in Colombia could lead to substantial gains in economic efficiency. Outside the study period, there were months when the marginal cost of consumption rose far higher than 10 cents per kWh. This occurs as a result of periodic shortfalls in inflows into the hydro reservoirs due to El Niño events. Currently, consumers pay a price that does not adjust to reflect the higher costs during these drought periods. This means that they do not have an incentive to reduce their electricity consumption.

2.3 Short-run Distortion from Inefficient Prices

We combine the results of the previous two sections to compare the monthly mean marginal cost of consuming electricity with the marginal prices that households face. Figure 15 shows the distribution of the ratio between the marginal price faced by each household and the marginal cost of consuming electricity. A value of 1 means that the household faces the true marginal cost. A ratio less than 1 means that the marginal price of consumption is below marginal cost, so the household consumes too much electricity. A ratio greater than 1 means that the marginal price exceeds marginal cost, so the household consumes too little electricity. All observations are weighted by the survey sample weights so that the figure is representative of the population of grid-connected Colombian households.

The distribution shows that for most households, the marginal price they face is too high. In the extreme, some households face a price that is more than three times greater than the marginal cost. These households are in Strata 5 and 6 in electricity distribution territories with high costs. Conversely, a minority of households face a price below marginal cost. These are households in Strata 1 or 2 with low consumption that places them on the subsidized first price tier, served by utilities with a low regulated base price.

For each household, we can quantify the difference between their optimal consumption (were they to face the correct price) and their actual consumption. We can then use this difference to calculate the welfare loss that is created by the price distortion. This calculation requires an assumption about the household's demand for electricity. We consider two types of demand: a linear demand model and a constant elasticity demand model. For both of these, we consider two alternatives for the price elasticity of demand: -0.15 and -0.30.

For each household and each set of demand assumptions, we calibrate a demand equation for that household to match the observed marginal price and observed consumption of the household. For the case of the linear demand model, the elasticity varies along the demand curve and so we can only calibrate the demand elasticity at a single point. We can then use the calibrated demand equation to compute the counterfactual consumption of the household, if the household faced the true marginal cost of electricity. Figure 16 illustrates the procedure. We observe the increasing block tariff faced by the household. We impute the actual consumption of the household, Q_{act}, based on the monthly electricity bill from the survey. Given that Q_{act} places the household on the second tier of the price schedule, the marginal price that the household faces is P_{marg}. We calibrate a demand curve for the household so that it passes through the point (P_{marg}, Q_{act}). Using this calibrated demand curve, we compute the optimal consumption Q_{opt} as the quantity where the demand curve crosses the marginal cost MC.

The deadweight loss from pricing above marginal cost represents the loss to society for the consumption that did not occur, even though the marginal benefit to the household of this lost consumption exceeded the marginal cost of that consumption. Note that for each unit of consumption between Q_{act} and Q_{opt}, the demand curve (that is, the marginal willingness to pay of the household) is higher than the marginal cost MC. We calculate the area of this triangle. For the opposite case in which the household faces a price below the marginal cost, consumption will be too high, and the deadweight loss will represent the difference between marginal cost and marginal willingness to pay, over the range of the excess quantities.

Table 1 summarizes the average deadweight loss from non-marginal-cost pricing, in US$ per household per month, broken down by the six stratum. Each of the four columns represents one of the four alternative assumptions for demand. Note that assuming a more price inelastic demand (an elasticity of -0.15 instead of -0.30) means that the difference between the actual and the optimal consumption is smaller, and so the deadweight loss is smaller. In the extreme, if demand were perfectly inelastic, then there would be no deadweight loss at all. The consumption distortion and the deadweight loss under the constant elasticity assumption is somewhat higher than under the linear demand model.

The deadweight loss for households in Strata 1 and 2 is between 25 and 71 US cents per month. The deadweight loss for these households is small because their demand for electricity is lower and the difference between their marginal price and marginal cost for also low. At the other extreme, households in Stratum 6 have a deadweight loss between $1.32 and $3.68 per month. These households have higher demand for electricity and face the most extreme difference between marginal price and marginal cost.

Table 2 presents the same deadweight loss calculations, but scaled as a proportion of electricity expenditure. The results show a U-shaped pattern across the strata. Households in Stratum 1 and in Strata 5 and 6 have the highest deadweight losses relative to their electricity expenditure.

These results quantity the magnitude of the short-run distortion from pricing electricity above or below marginal cost. In the short-run, electricity demand is assumed to be constant, and the mispricing causes the household to move up or down along their demand curve. However, in the long-run, the household might adjust their bundle of energy-using durable goods. There are many more choices that the household can make to adjust their electricity demand, potentially leading to a shift in or out of the entire short-run electricity demand curve. In other words, electricity demand may be much more price elastic in the long-run, meaning that welfare distortions are potentially much larger than shown in Tables 1 and 2.

3 Long-run Implications of Inefficient Retail Pricing//in Colombia

The most important energy consumption decisions made by households are the choice of energy-related durables. For example: What type of car to buy? Whether to install energy-efficient materials? What type of cookstove to use? These decisions constrain the household's short-run decisions for years or even decades. If the household decides to buy a fuel-inefficient car, this will have a much larger effect on gasoline consumption over the following years than minor changes in driving habits.

In this section, we analyze the relationship between the electricity tariff structure in Colombia and two types of choices that may be made by households: whether to install rooftop solar and whether to buy an electric car. The incentives created by non-marginal-cost pricing operate in opposite directions for these decisions. If households pay a marginal price for electricity that exceeds social marginal cost, there will be too much investment in solar panels and too little investment in electric cars, relative to the socially optimal level of investment.

3.1 Incentives for Installation of Residential Solar

In this section we model the potential market for residential rooftop solar in Colombia. We compare the existing tariffs (including the recent regulations for distributed generation) to an alternative tariff in which households pay a marginal price equal to marginal cost. The goal of the analysis is to show the interactions between the tariff structure and the solar adoption potential. We do not attempt to predict the future development of the solar market. This will depend on the unknown future path of solar installation prices.

Our analysis complements the existing research on the residential solar market in Colombia (Castaneda et al., 2017; Jimenez, Franco and Dyner, 2016; Castaneda, Franco and Dyner, 2017; Castaneda, Zapata and Aristizabal, 2018; Cardenas et al., 2017). These papers adopt a system dynamics framework that allows simulation of feedback effects over a multidecadal time horizon. Solar adoption in these papers follows a diffusion model and all assumptions and variables are national-level aggregates. In contrast, our analysis models the adoption decision at a household level, using current data on tariffs, consumption, solar potential, and installation eligibility. This allows us to model the heterogeneity in adoption potential and its effect on individual electric utilities.

CREG Resolution 30 of 2018 defined the rules for paying small renewable producers, including households with rooftop solar installations (Comisión de Regulación de Energía y Gas, 2018). Distributed generators will have two meters: one to record the power withdrawn from the grid and the other to record the power sent to the grid. There are three cases to consider for the calculation of the monthly bill:

1. For the hours in which self-generation is less than consumption, no electricity is sent to the grid, and the electricity withdrawn from the grid is reduced by the amount of the generation. This occurs "behind the meter" and is not observed by the retailer.

The consumer benefits by avoiding the full retail price on the self-generated units.

2. For the hours in which self-generation exceeds consumption, the excess generation is exported to the grid. As long as the total amount of exports in the billing period is less than the total amount of imports, the exports are subtracted from the imports to calculate the monthly bill. However, the customer pays the retailing component of the regulated tariff on the quantity of exported generation.

3. If the total exports in the billing period exceed the total imports, the customer receives the average wholesale electricity price for the surplus generation.

We model the potential market for residential solar under two tariff assumptions. First, we consider the existing nonlinear tariffs with the application of the Resolution 30/2018 regulation on the pricing of excess generation. Second, we consider our proposed optimal tariff structure for which the household pays the social marginal cost of electricity. In this second scenario, we assume the excess solar generation is priced in a net metering framework, with all sales and purchases of electricity occurring at the marginal cost price.

We limit our analysis to the subset of households that could plausibly adopt private residential solar systems, based on the sample restrictions used by Hancevic, Nuñez and Rosellón (2017). We focus on owner-occupied houses (not apartments). Because of the weight-bearing requirements for solar installations, we limit our sample to houses with brick or concrete block walls. The survey does not have information about the roof material. With these restrictions, our sample of potential solar adopters drops to slightly more than 30% of the households in Colombia. Most of the decrease is due to the significant fraction of households in rental properties or in apartment buildings.

For the potential adopters, we obtained information on the annual solar potential of the dwelling location from the Global Solar Atlas. This resource reports the amount of electricity that could be generated at a location assuming an optimal installation angle for the solar panels. The calculation is based on multi-year time series of solar radiation and air temperature. The calculation accounts for hill shading effects and other common reasons for losses at a location, such as snow or dust.

The spatial resolution of the Global Solar Atlas is approximately 1×1 kilometer. The survey data only reports the municipality in which the household lives. Instead of using an average value for the municipality, we use geographical shape files from DANE that show the outline of the largest urban center in each municipality. We then extract the mean solar generation potential for the cells inside each urban area.

For large urban areas, there is often a big difference in the solar potential for different parts of the city. This is especially relevant in Colombia where many cities are located in mountain valleys in which terrain effects can be important. Because we do not know their exact location, we assign each household the mean generation potential for its urban area. We apply a 5 percent discount to the solar potential to reflect the inefficiencies associated with small rooftop residential systems.

We model the adoption of solar installations of different sizes: 1 kW, 2 kW, and 3 kW. While a 1 or 2 kW installation would be considered small by U.S. standards, their generation potential is larger than the annual electricity consumption for many households in Colombia. The potential annual generation from a 1 kW system varies between 1,133 kWh and 1,662 kWh across the households in our data. This is equivalent to a capacity factor of between 13% and 19%.

To calculate the change in the electricity bill from installing solar, we need to make assumptions about the timing of electricity consumption and the timing of electricity generation during the day. Based on the self-generation regulations, this timing determines the value the household receives from its solar installation.

We use hourly solar radiation data from IDEAM for six monitoring locations in Colombia: Bogotá, Medellín, Bucaramanga, Barranquilla, Villavicencio, and Calí, for the three-year period from 2016 to 2018. All of our analysis is based on annual averages and we do not account for changes during the year in sunshine or electricity consumption. Because of this assumption, we average the solar radiation data by hour-of-day across the six sites. Figure 17 shows the hourly mean solar radiation at each location, scaled so that the daily total is equal to 1. There are minor differences in the timing of the peak across the locations, reflecting differences in longitude. True midday (when the sun is directly overhead) differs from clock midday based on east-west location relative to the time zone. The thick blue line shows the mean across all locations. We assume that all households in Colombia have the same timing of solar generation.

For the timing of electricity demand, we use data from XM for the hourly regulated demand for each retailer. Residential electricity consumers in Colombia do not have real-time meters: the utility only observes total electricity consumption over a month. However, large electricity consumers paying a unregulated price for electricity are required to have real-time meters to measure their hourly consumption. Total hourly demand for each distribution network is also measured at the substations where the distribution network withdraws electricity from the transmission network. This means that the hourly demand for regulated customers can be computed as the difference between the total withdrawals, less the consumption of the unregulated consumers.

There are many electricity retailers in Colombia serving non-residential customers, with an hourly load shape that is distinct from the pattern for residential customers. We focus on the subset of retailers that are integrated with a distribution network. Nearly all residential customers are served by an integrated retailer-distributor of electricity.

Figure 18 shows the hourly load shapes for our subset of electricity retailers in Colombia. The hourly means are scaled so that the daily total demand is equal to 1. For almost all retailers, peak electricity demand is between 7:00PM and 8:00PM. Demand is lowest between 3:00AM and 4:00AM. We average across the retailers and use the mean hourly load shape (thick blue line on Figure 18). Just as for solar generation, we assume that all locations in Colombia have the same timing of hourly demand.

For each household who might potentially adopt solar, we have an estimate of their annual solar generation. We have their electricity consumption for one month, imputed from their self-reported electricity expenditure. We assume that annual electricity consumption is twelve times the monthly electricity consumption. This assumption is less problematic in Colombia than it might be in a different setting, because the tropical climate means there is limited seasonal variation in electricity demand.

The electricity bill for households who install solar will depend on the hourly timing of their generation relative to their demand. If annual generation is very small relative to annual demand, then this generation will directly offset the consumption. The household will withdraw less electricity from the grid during peak solar hours. From the point of view of the electricity distributor, the only change is that the household's metered consumption is lower.

Suppose annual generation is 50 percent of annual consumption (second panel of Figure 19). Assuming the hourly shape of household load and generation is the same as the national average, there will be six hours in the middle of the day when the generation completely covers the household's consumption and the household is sending its excess generation to the grid. Of the total daily solar generation, 81.1 percent covers the household's own consumption and offsets the hourly imports from the grid. The remaining 18.9 percent is the excess generation that is sent back to the grid in the middle of the day. Based on the rules of the CREG 30/2018 resolution, the excess 18.9 percent of generation will be charged the retail component of the base regulated price. The household's electricity bill will be calculated using the usual tariff for the 50 percent of consumption that is not matched by self-generation, plus the retail charge for the 18.9 percent of exported generation.

Suppose instead that annual generation is exactly equal to annual consumption (second panel of Figure 19). In this case, the billed consumption for the year will be zero, because the generation cancels out the demand. However, the household will still have to pay the retailing charge for the share of generation that is sent to the grid. Based on the assumptions for the pattern of household load and solar radiation, 52.7 percent of the solar generation will be subject to this retail charge. This means that the household will still pay a positive, albeit smaller, electricity bill.

We repeat this calculation for every household in our sample who is a potential candidate for solar generation. For the three different sizes of solar installation, we calculate the new electricity bill for the household based on the existing retail tariff structure and the CREG 30/2018 methodology. The new bill may be negative if the solar generation is sufficiently greater than the household's electricity consumption. We calculate the change in the electricity bill coming from the solar investment, as the difference between the hypothetical bill with solar and the household's existing electricity bill without solar.

Investing in solar will be optimal for the household if the present value of the calculated reductions in their electricity bill exceed the initial capital cost of installing solar. We assume the life of the solar panels is 30 years. The two crucial parameters for the calculation are the discount rate and the capital cost of solar. We explore the sensitivity of our results to a range of different values for these parameters. For the discount rate, we use annual discount rates of 2.5, 5, and 10 percent. Because we assume there is no change in the level of tariffs, these rates should be interpreted as real discount rates.

Costs for residential rooftop solar installations declined by between 47 and 78 percent between 2010 and 2017 (International Renewable Energy Agency, 2018). However, considerable regional variations in installed solar costs remain. For example, the cost in California is more than three times higher than in India. To reflect the uncertainty in investment costs, we show the results for a wide range of values, from US$500 to US$4000 per kW. As reference points, we highlight the residential solar installation costs for the U.S. ($3,600/kW), Brazil ($2,600/kW), and Spain ($1,400/kW), also from International Renewable Energy Agency (2018). The results for the range of prices can also be regarded as simulations for the effect of possible future declines in installation costs.

The potential solar panel adoption, as a function of panel price, discount rate, and system size, is reported in Table 3. Figure 20 shows the same information for a system size of 2 kW. Both the table and figure report the share of the population for whom installing solar panels would be a privately-optimal financial decision. This may not correspond to the actual adoption rates. There may be unobserved barriers to installation such as financing constraints or site-specific restrictions. Alternatively, there may be household preferences that lead to solar installation even when this is not optimal from a purely financial perspective, perhaps due to conspicuous consumption or to concerns about the environment (Bollinger and Gillingham, 2012).

Nearly 70 percent of households are unable to install solar because they rent or live in an apartment. The maximum penetration rate for solar is 31.4 percent of households. For a discount rate of 5 percent, this level of penetration is possible when panel prices fall below $1,000 per kW. For panel prices typical of those observed in Brazil, and assuming a 5 percent discount rate, about 10 percent of households would find it optimal to install a 1 kW solar unit, and 5 percent would find it optimal to install at 2 KW unit. As expected, potential adoption rates are higher for lower values of the discount rate and panel price.

Under the existing tariffs, potential adoption rates are decreasing in the panel size. This is because the financial benefits of installing solar are largest for the initial kilowatt-hours of generation. For households in Strata 1 to 3 and on the second price tier, the savings from solar diminish once they have reduced their billed consumption below the first tier threshold of 130 or 173 kWh per month. Even for households in Strata 4 to 6, the financial benefits from solar are much lower once they have offset their monthly consumption. The second reason for the negative relationship between adoption rates and panel size is our assumption for the analysis that the cost of solar installation is a constant multiple of the system size. That is, a 2 kW system is assumed to cost twice as much as a 1 kW system. This assumption eliminates the possibility of scale economies in solar installation.

We perform the same calculation of potential adoption rates under an economically efficient tariff in which households pay the marginal cost for their electricity use and can sell their excess generation at the same marginal cost. The results are shown in the final column of Table 3. Under the counterfactual tariff, adoption rates are independent of system size. This is because both installation cost and generation revenue (or value of avoided consumption) are constant multiples of size. A 2 kW system would not only cost twice as much as a 1 kW system, but the financial benefits would be also twice as large.

At high panel prices, adoption of solar under the efficient tariff would be substantially lower than under the existing tariffs. For example, for a panel price of $3,000/kW, 6.5 percent of households would find it optimal to install a 1 kW solar system at a 5 percent discount rate, under the existing tariffs. Under the efficient tariff, no households would find it optimal to adopt, for the same panel price and discount rate. This difference is due to the existing tariff inducing solar adoption that is inefficient from the perspective of social welfare. For a discount rate of 5 percent, the present value of social benefits from the electricity produced by a solar panel in Colombia is less than $3,000/kW. This comparison is based on our calculation of the value of electricity generation, including the avoided losses and avoided externalities. However, for 6.5 percent of households, the **private** benefits of installing solar would exceed $3,000/kW in present value terms. This is a pure artefact of the inefficient and distortionary tariffs in which the marginal price faced by most households exceeds marginal cost. Social welfare would be improved by implementing a tariff to discourage the installation of solar by such households.

At low panel prices, the ranking of adoption under the existing and counterfactual tariffs reverses. For example, for a panel price of $1,500/kW and discount rate of 5 percent, 21.3 percent of households would find it optimal to install a 1 kW system, given the existing tariffs. For the efficient tariff, 26.2 percent of households would find installation optimal under those assumptions. This is because the existing tariff **undervalues** the electricity generation for some households. For some households in the lower strata, the marginal price avoided by reducing their billed consumption is less than marginal cost. This can even occur for households on the second price tier, once their solar generation drops them on to the first tier. For households with solar generation exceeding their monthly consumption, the price they receive for their excess generation is less than the social value of that generation, because the wholesale price does not reflect the avoided losses and externalities.

The advantage of the proposed efficient electricity tariffs is that they provide the correct incentives to households for choosing whether or not to install solar. They align the private benefit of solar generation with the social benefit. Under the existing tariffs, the households who would have the largest incentive to install solar are high-income households in Strata 5 and 6 who are paying a high marginal price for electricity. Household on the first tier of Stratum 1 have no incentive to install solar. However, from a societal viewpoint, the best locations to install solar generation depend on the availability of the solar resource, not on the socioeconomic characteristics of the neighborhood.

3.2 Effect of Solar Adoption on Electric Utilities

Another consideration for the interaction of tariff design with residential solar adoption is its effect on the financial position of the electric utilities. Under the existing tariffs, all fixed costs are recovered through the volumetric charges. The first households to install solar—the ones who would find it optimal to install even with high panel prices—are those who are paying the highest marginal prices. These are the customers who are currently making the largest contribution towards covering the utility fixed costs.

We assume that households who install rooftop solar will still stay connected to the grid. Full disconnection would require the purchase of batteries to store electricity during the day for use after the sun sets. It would likely also require the purchase of a backup generator for use during extended periods with low solar output. If customers keep their electricity connections, then the fixed costs for running the network are unlikely to fall. It is possible that fixed costs would even rise, given the increase in complexity of running a distribution network that incorporates distributed generation.

Given that fixed costs are assumed to stay the same, the decline in revenue from households who install solar would mean that regulated rates would need to rise. These higher rates would provide incentives for additional households to install solar, leading to a cycle of declining revenue and increasing rates that has been labelled as the "utility death spiral" (Costello and Hemphill, 2014; Castaneda et al., 2017). This would adversely affect the remaining households—the renters, the apartment-dwellers, the low-strata households—who are either unable to install solar or for whom it is not optimal.

In the specific context of the tariff and subsidy structure in Colombia, the adoption of residential solar would increase the fiscal cost of the electricity subsidies. There are two effects. Many of the initial adopters are the Strata 5 and 6 households who currently pay a 20 percent contribution towards the subsides. This contribution disappears when the solar panels are installed. Second, the increase in regulated rates to compensate for the decline in fixed cost recovery would increase the size of the subsidy for the low-strata households. This is because the subsidy is calculated as a percentage of the regulated base price.

We demonstrate these effects by calculating the decline in fixed cost contributions from residential users as the adoption of solar panels increases, under the existing tariff structure. For this calculation, we assume a panel size of 2 kW, and use the same range of values for discount rates and panel prices as before.

On average, the utility fixed cost recovery that is at risk from solar adoption rises quickly as panel prices drop below $3,500/kW (Figure 22). At high panel prices, the percentage decline in fixed cost contributions exceeds the share of households who adopt solar. For example, at the Brazilian panel price of $2,600/kW, 5 percent of households would adopt solar given a discount rate of 5 percent, but fixed cost contributions would fall by more than 6 percent. This is because the first households to adopt solar are exactly the customers who are making a disproportionate contribution towards fixed costs.

At very low panel prices, slightly more than 26 percent of fixed costs would be lost once all eligible households adopt solar. This is lower than the percentage of adopters (31 percent) because of the charge paid by panel owners for electricity that is sent back to the grid. This component of the CREG 30/2018 resolution helps to partially offset the revenue decline.

The summary analysis at a national level in Figure 22 obscures the considerable heterogeneity across utilities in Colombia. Figure 23 shows the drop in fixed cost recovery by electricity supplier, assuming a 2 kW solar installation, a 5 percent discount rate, and an installation cost of $2,000/kW. For these assumptions, the national average in Figure 22 is just over 11 percent. However, at a supplier level, the at-risk fixed cost recovery varies from 2 percent for DISPAC to nearly 19 percent for Enelar. This variation exists due to regional differences in the electricity tariffs, the share of consumers paying unsubsidized prices, and the potential solar generation.

We demonstrate the relationship between prices, solar potential, and the utility-level decline in fixed cost recovery. Figure 24 shows the mean marginal price by utility on the horizontal axis. The mean marginal price combines the differences in the regulated base prices and the distribution of customers by stratum and price tier. DISPAC customers face low marginal prices—most of them are in Strata 1 and 2 and their consumption lies on the first price tier. Enelar customers face high marginal prices. As expected, there is a positive relationship between mean marginal prices and at-risk fixed costs. Regions with many households facing high marginal electricity prices will have higher rates of solar adoption.

Figure 25 shows a similar relationship between mean solar potential and the decline in fixed cost recovery. Utilities with highest solar generation potential, such as Electricaribe, ESSA, and Enelar, are most at risk of customers installing solar. The utility serving the Arauca department, Enelar, is particularly susceptible, given its high marginal prices and high solar potential. There are few such concerns for DISPAC in the Chocó department, one of the wettest regions in the world.

We emphasize that the above results apply only to the decline of utility revenue from residential solar adoption under the existing tariff structure. Our proposal for an economically efficient tariff would avoid this problem altogether. As long as households who install solar stayed connected to the grid, there need be no decline in revenue if households pay the marginal cost per unit of consumption and then a fixed monthly charge.

3.3 Adoption of Electric Vehicles

The distortionary electricity tariff structure in Colombia has the opposite effect on electric vehicle adoption compared to rooftop solar adoption. Marginal prices that are higher than the socially optimal prices discourage consumers from switching from gasoline to electricity for transportation. This contrasts with solar, for which higher-than-optimal marginal prices encourage too many inefficient installations of panels.

Our analysis of electric vehicle adoption follows a similar approach to the previous sections on solar adoption. In particular, we treat this as a purely financial decision, in which the household will switch from a gasoline to an electric vehicle if the present value of fuel savings exceeds the increase in purchase price. Because this analysis focuses on the design of electricity tariffs, we ignore the other determinants of electric vehicle adoption. Negative factors include the restrictions on driving distance because of battery size ("range anxiety") and the lack of convenient locations for recharging (Li et al., 2017; Li, 2017; Springel, 2016). Positive factors might include the perceived social and environmental desirability of electric vehicles (Sexton and Sexton, 2014).

The electric vehicle market is Colombia is small but growing. In 2018, there were 390 battery electric vehicles sold in Colombia, compared to 136 in 2017. For plug-in hybrid electric vehicles that run on gasoline or electricity, 273 were sold in 2018 compared to 57 in 2017. Battery and plug-in hybrid electric vehicles had a market share of 0.26 percent out of the total vehicle sales of 256,662 in 2018. The most popular battery electric vehicles in Colombia are the BMW i3, the Renault Twizy Technic, and the Renault Zoe. These vehicles have a combined share of 76 percent of the battery electric vehicle market (Asociación Colombiana de Vehículos Automotores, 2019*b*).

We consider the choice between two vehicles with the same make: the gasoline-powered Renault Logan and the electric Renault Zoe. We use the Renault Logan because it was the second-most popular vehicle in Colombia in 2018, with a market share of 4.7 percent.[4]

[4] The most popular make and model was the Chevrolet Spark, with a market share of 5.2 percent in 2018. Chevrolet does not sell an electric vehicle in Colombia and so it would not be possible to do a within-make comparison. Gasoline market share data are from Asociación Colombiana de Vehículos Automotores (2019*a*).

The price of the Renault Logan is 34.59 million pesos, or US$11,700 based on the 2016–17 exchange rate. The price of the Renault Zoe is 99.99 million pesos, or US$33,800.[5]

For both vehicles we calculate the driving price in pesos per kilometer. For gasoline, we obtained station-level data on regular gasoline prices from Ministerio de Minas y Energía (2018). We aggregated the gasoline data to the municipality-month level and matched each household to the gasoline price in its municipality. We then calculated the driving price using the Renault Logan fuel efficiency of 17.1 kilometers per liter. For electricity, we used the marginal electricity price faced by each household given their tariff and current consumption. We then used the fuel efficiency of the Renault Zoe of 0.137 kWh per kilometer to calculate the driving price for each household.

We assumed that both vehicles have a life of 15 years and zero scrappage value after that time. We also assumed that the annual driving distance in either vehicle is 11,000 kilometers. Unfortunately, there is no national travel survey data available for Colombia to provide a better estimate of typical driving distances. Davis (2019*b*) provides evidence from the U.S. National Household Travel Survey that electric vehicles are driven less than gasoline vehicles: 7,000 versus 10,200 miles per year. With no better information, we use the U.S. driving distance for electric vehicles as our distance estimate for Colombia.

Given the price data and distance assumption, we calculate the net present value of choosing a Renault Zoe instead of a Renault Logan, for three values of the real annual discount rate (2.5, 5, and 10 percent). We restrict our analysis to those households who report owning a car in the survey. We further restrict the sample to only include households in an owner-occupied house or apartment. For the United States, Davis (2019*a*) shows that electric vehicle ownership is rare for households living in rental properties, probably because of the large sunk cost of installing a charger. Only about 10 percent of households in Colombia satisfy both restrictions.

We show the electric vehicle adoption results for a range of prices for the Renault Zoe (Figure 26). At the current price of US$33,800, there are no households in Colombia who would find it optimal to buy the Zoe instead of the Logan. This remains true for any plausible alternative assumptions on driving distance and discount rate. At a 5 percent discount rate, the price of the Zoe would have to drop by nearly 60 percent to $14,000, in order for half of vehicle purchasers (5 percent of the population) to choose the Zoe instead of the Logan.

[5]Vehicle prices for Renault models as of March 2019 in Colombia are from `https://www.renault.com.co/gama/automoviles.html`.

We repeat the calculation using our economically efficient electricity tariff. For almost all of our eligible sample, the efficient tariff is lower than their existing marginal price, which reduces the cost of driving the electric vehicle and encourages adoption. With the efficient tariff, households will switch to electric at a higher electric vehicle price (Figure 27). For the 5 percent discount rate, a price drop for the Zoe to $15,000 would make it optimal for about half of vehicle purchasers to choose it instead of the gasoline vehicle.

Electric vehicles are still far from being a mass-market alternative for personal transportation in Colombia. The most popular cars in Colombia in 2018—Chevrolet Spark, Renault Logan, Renault Sandero, and Kia Picanto—are all priced at slightly more than $10,000. Prices for electric vehicle sedans are three or more times higher than the prices for these gasoline vehicles. The electric Renault Twizy Technic has a price ($13,500) that is comparable to the most popular gasoline models. However, it has a three-door ultra-compact design and a limited range, making it a poor substitute for a gasoline sedan for most purchasers.

Our results illustrate the distortion in electric vehicle adoption decisions created by the existing retail electricity tariffs. Although the practical relevance of this distortion is small, it will become more and more important as battery technology improves and the prices of electric vehicles drop. Introducing an economically efficient retail tariff will not magically transform the market for electric vehicles in Colombia. However, it will eliminate one barrier that would otherwise stunt the development of this market.

4 Empirical Analysis of Alternative Retail Pricing Schemes

Under an efficient electricity tariff, the price that households pay for an additional kWh of consumption in an hour will be exactly equal to the social marginal cost of supplying the household with an additional kWh in that hour. Because this marginal cost varies across hours in the day and days in the year, the price will also vary by hour under the optimal tariff. However, charging a different price each hour requires an electricity meter that can record the real-time consumption. In Colombia, most households still have mechanical meters that must be read manually, usually on a monthly basis.

We approximate the efficient tariff by considering a price per kWh of consumption that varies monthly based on the social marginal cost. This price is the volume-weighted average of the hourly social marginal costs. Because the true hourly consumption of an individual household is unobserved, the volume weighting would be based on a typical load profile for a residential electricity user.

Setting a price per kWh based on marginal cost will avoid distortions in the household's electricity consumption decisions. This includes both short-term decisions (when to turn on and turn off lights) and long-term decisions (what type of appliance to buy). Importantly, such a tariff will provide the correct incentives to adopt, or not to adopt, new energy technologies such as electric vehicles or distributed solar.

The problem with charging each household a price based on the marginal cost is that the total revenue collected from such a tariff is likely to be insufficient to cover the total cost of supplying electricity. Most of the costs for electricity transmission, distribution, and retailing are fixed costs that do not vary based on electricity consumption. Therefore, these fixed costs are not included in the marginal cost calculation. Marginal cost pricing for residential users would lead to a revenue shortfall.

Instead, the remaining fixed costs would need to be recovered through a fixed charge in the electricity tariff. This fixed charge would be paid by each household as part of their electricity bill. By definition, the fixed charge does not depend on the electricity consumption of the household. Therefore, it avoids the consumption distortion created by pricing above or below marginal cost. Such a tariff is called a **two-part tariff**: households pay the marginal cost for their consumption plus a fixed charge set to recover the fixed costs of supply.

The simplest method for setting a fixed charge would be to calculate the total costs that need to be recovered and divide these evenly across all households. There are two problems associated with this approach. First, for households with low electricity consumption, the fixed charge may exceed the consumer surplus they receive from using electricity. It would then be optimal for that household to disconnect from the grid rather than stay connected and pay the fixed charge. This is likely to be seen as unacceptable by policy makers.

A second consideration relates to fairness. For economic efficiency, it does not matter how the fixed charge is allocated across households (assuming this causes no households to disconnect), because every household still faces the correct incentives for their marginal consumption. However, from an equity perspective, it could be argued that households who benefit most from having an electricity connection should pay a greater share of the cost of providing the service.

4.1 Calculation of the Revenue Requirement

We undertake the analysis at the level of the electricity distributor. For each distributor, we assume that the existing base price for residential users is being calculated correctly so that it recovers all costs and provides a return on invested capital, given the existing level of consumption. Implicit in the base price calculation is an allocation of fixed costs between residential and non-residential users. This allocation is also held constant.

For each distributor, the total revenue requirement from the residential consumers is the base price multiplied by aggregate residential consumption. This revenue has to cover both variable and fixed costs. The variable cost per kWh will be the wholesale price of electricity each month, plus the reconciliation payments and losses. This is the private marginal cost component of the calculation in the previous section. Total variable costs are the variable cost per kWh multiplied by aggregate residential consumption. The difference between the total revenue requirement and the total variable costs will be the fixed cost requirement.

Revenue to cover the fixed cost requirement may come from three sources. First, there are existing subsidy transfers to the residential consumers of each distributor: both from the contributions paid by the non-residential users and from the government top-up of any subsidy shortfall. Assuming the value of these existing transfers remains fixed, these subsidies can be used to offset the fixed costs.

Second, under the optimal tariff, households would pay both the private and social marginal costs associated with their electricity consumption. This will exceed the variable costs that are paid by the distributor, because it is assumed that the distributor does not have to pass on the external cost component of the tariff to a third party. In other words, the carbon tax embedded in the optimal tariff provides a potential source of revenue to cover fixed costs. Implicitly, this becomes a carbon tax with a lump-sum rebate to households through their electricity bill. Such a scheme for carbon pricing has been proposed in several jurisdictions.

Finally, the remaining costs that are not covered by the subsidy transfers or from carbon taxation would be recovered from households through a fixed charge on their electricity bills. In our setting, the current subsidy transfers can be calculated as the difference between the total revenue requirement and the total revenue from residential users. The carbon tax revenue is the tax per kWh, multiplied by the counterfactual consumption under the new tariff. The revenue to collect through the fixed charge is the residual amount.

For reporting our results, we use the assumption of linear electricity demand, calibrated for each household to give a price elasticity of demand of -0.30 at current prices and quantities. For each electricity distributor, we use the above procedure to calculate the fixed cost requirement and its split into the three components. Results are reported in US dollars per household per month.

Figure 28 shows the breakdown of the fixed cost requirement, per household per month, by electricity distributor. The total length of the bar represents the fixed costs that need to recovered. These vary from slightly more than $10 per household per month for the utility in Huila to $25 per month for the utility in Arauca. In general, the total fixed costs per household are somewhat lower for distributors that operate in major metropolitan areas, such as Codensa in Bogotá and EPM in Medellín. This is because it is cheaper to provide service to customers in places with higher population density. Total fixed costs per household tend to be higher for distributors operating outside of major metropolitan areas and in places with lower population density.

Carbon revenue per household scales directly with mean electricity consumption. It is highest for lowland areas with warmer climates where consumption is higher. There is more variation in the size of existing subsidy transfers per household. They are highest for distributors with greater numbers of customers in Strata 1 and 2, located in areas below 1000 meters where the subsidized quantity is higher. The distributors with the highest subsidy per household are in Arauca, Caqueta, and Chocó (DISPAC). Their subsidies exceed $13.50 per household per month. The distributors with the lowest subsidies include Boyacá, Codensa, and Emcali. These firms have relatively fewer Stratum 1 customers and, because the first two operate in highland areas, the subsidized quantity per user is lower.

The residual component of fixed costs is the fixed charge that will be paid by households. For Putumayo, the fixed charge required is about $1 per household per month, and for Dispac the required fixed charge is negative. This is because the existing subsidies for these firms already cover most or all of the fixed costs. The maximum fixed charge required is over $6 per household per month, for the distributor Emcali. We focus next on how these fixed charges might be allocated across households.

4.2 Equal Fixed Charges across Households

The first scenarios we analyze are that of equal fixed charges across all households in an electricity distribution territory. The distributional effect of these tariffs provides a useful comparison for the alternative tariff methodologies.

We calculate the change in the household consumer surplus as a result of switching from the current tariff to the counterfactual tariff. We assume linear demand for electricity and, for each household, we calibrate their demand to match existing prices and consumption for a price elasticity of demand of -0.30. For the existing tariffs, consumer surplus is calculated based on the current marginal price faced by the household, plus the value of any inframarginal subsidies. For the new tariffs, consumer surplus is calculated based on the new variable charge and corresponding counterfactual consumption, less the amount of the fixed charge.

We first consider a scenario in which all subsidy transfers for electricity service are eliminated. This includes both the cross-subsidy from non-residential users and the subsidy top-up from the government. The full residential share of fixed costs of each distribution utility, less the revenue from carbon taxes, would be recovered through an equal fixed charge paid by each household served by the utility. For this scenario and all others in this section, we assume that the variable charge per kWh of consumption is set to the monthly average of the social marginal costs.

Eliminating the subsidy transfers would leave most Colombian households worse off (Figure 29). Households in the lowest three deciles of the income distribution would be about US$9 worse off each month. Many of the low-income households currently face a marginal price below the marginal social cost. Under the new tariff, their marginal price would rise, and so their electricity consumption would fall. In addition, they would pay a new fixed charge equal to the first two blocks in Figure 28. This leaves them much worse off on average.

Households in the highest income decile would be better off by nearly $3 per month after the elimination of the subsidy transfers. Many of these households are in Strata 4, 5, or 6, and so they did not receive any benefit from the subsidies. Instead, they often paid a price per kWh that greatly exceeded the social marginal cost. Under the new tariff, there is a substantial fall in their marginal price, which would lead to an increase in their electricity consumption. The benefit from the lower variable charge and higher consumption would offset the higher fixed charge.

Taken in isolation, it appears that eliminating all subsidies and transitioning to an optimal two-part tariff is unlikely to be politically feasible. However, it is possible that the resources currently being allocated to electricity subsidies could be used for alternative social transfer programs or for reducing taxes. For example, the resources could be provided directly to households through a cash transfer program. The net effect on households would depend on the exact details of how such a program is designed.

To enable a more tractable comparison across different tariff methodologies, we focus on a scenario in which the existing subsidy transfers to each distribution utility are held constant at the 2016–17 levels. The fixed charge for each distribution utility is assumed to be the same for all households. It is equal to the fixed costs, less the carbon tax revenue and subsidy transfers, divided by the number of households.

Figure 30 shows the effect by income decile of an equal fixed charge within each distribution territory. On average, households would be better off by about $1 per household per month. However, this benefit is far from evenly distributed. Households in the bottom half of the income distribution are worse off than under the current tariffs, by about $2 per household per month for deciles 1 to 3. Most of the benefits of the new tariff would accrue to households in the top four deciles. Households in the highest income decile are particularly better off, by about $9 per household per month.

4.3 Methodologies for Targeting Fixed Charges

As discussed above, a transition to an efficient two-part tariff for electricity in Colombia will almost certainly require a mechanism to vary the fixed charge across households. Optimally, differences in the fixed charge across households would correspond to differences in their willingness to pay for electricity. The practical challenge is that the fixed charge cannot be calculated based the observed consumption of a household—by definition, it would then no longer be a fixed charge. We therefore need to develop proxies for the willingness to pay that are not based on contemporaneous consumption.

For the first approach, we use the classification of households under the government-subsidized health insurance program. Eligibility for government-subsidized health insurance in Colombia, as well as eligibility for other programs including housing subsidies, educational scholarships, and school lunches, are determined by a proxy means test known as SISBEN.[6] The SISBEN interviews do not cover the entire population. Rich households who almost certainly would not qualify, including households living in higher strata areas, typically do not participate.

In our survey data, respondents report whether they have private health insurance through their employers or whether they qualify for the subsidized insurance. Households qualify or not for subsidized insurance based on a proxy means test. We use this 0/1

[6] Miller, Pinto and Vera-Hernández (2013) study the effectiveness of the health subsidy program at reducing risk, enhancing preventive care, and improving health outcomes. Camacho and Conover (2011) study strategic manipulation of the SISBEN eligibility formula by local politicians.

classification to allocate the fixed costs by assuming that households with at least one member who qualifies for subsidized insurance will pay a **zero** fixed charge on their electricity bill. For each electricity distributor, all of the fixed costs that need to be recovered are divided evenly among their customers who do not have the subsidized insurance.

For the second approach, we use the predicted electricity consumption of each household based on observable characteristics. Specifically, we run a regression of the square of electricity consumption on household characteristics. We then use the estimated coefficients to predict the squared consumption for each household. The share of fixed costs allocated to an individual household will be its predicted squared consumption, divided by the sum of predicted squared consumption for all households in the distribution service territory.

Wolak (2018) provides additional details to motivate the use of predicted squared consumption to allocate fixed costs. Heuristically, using the predicted square of consumption allocates a relatively larger share of costs to households with characteristics associated with high electricity consumption. More formally, if we assume that households have a linear demand curve for electricity with a constant slope, then the consumer surplus from electricity consumption will be a constant multiple of the square of consumption. Using the square of consumption to calculate the fixed cost shares will give an allocation of fixed cost based on willingness to pay.

One way to predict electricity consumption is using the characteristics of the dwelling. We regress the squared consumption of each household on the dwelling type, number of rooms and number of bedrooms, the wall and floor materials, and the type of bathroom and kitchen. Each dwelling characteristic is interacted with the distribution firm, allowing the effect of dwelling characteristics to differ across regions. From this regression, we then predict the squared consumption for each household and use this predicted value to calculate the share of fixed costs.

The prediction approach based on dwelling characteristics is relevant because it would be feasible to implement this methodology in practice. The inputs to the prediction model incorporate information that is already available in the national cadastral database in Colombia.[7]. For each land parcel, the database includes information on the building footprint, number of rooms, number of bathrooms, floor area, and a measure of the quality of construction. This cadastral data could be used to predict the electricity consumption of each dwelling. Then the share of the squared predicted consumption out of the total could

[7] https://geoportal.igac.gov.co/es/contenido/consulta-catastral

be used to set the fixed charge for each dwelling.

This methodology is closely related to the new methodology adopted by the national statistical agency DANE for determining the household stratification. Rather than choosing strata based on external characteristics of neighborhoods that are observed during enumerator site visits, the refined approach uses the cadastral data as the primary input in the classification decision. Importantly, distribution utilities are required to include the cadastral identifiers in their customer databases. This would facilitate matching the consumption data to the dwelling characteristics.

What is most appealing about our methodology is that it avoids the intermediate step of the coarse classification of households into six strata. The lack of granularity of the strata means the loss of potentially valuable information in the cadastral data about each household's willingness to pay for electricity. Using dwelling data to predict the square of electricity consumption allows for finer differentiation across different types of households.

A second way to predict electricity consumption is by using characteristics of both the dwelling and the household. The household characteristics include household size, household income, and ownership of various types of appliances. We regress the squared consumption on these characteristics, interacted with the distribution service territory. We then calculate the fixed charge of each household based on the share of the squared predicted consumption out of the total. The information requirements for predicting consumption using household characteristics are greater and would likely require in-person interviews. However, this type of information collection is not without precedent in Colombia, given the use of in-person interviews for targeting the SISBEN health insurance subsidies.

Predicting willingness-to-pay for electricity using household characteristics, and setting the fixed charge accordingly, is particularly appealing from a theoretical perspective. When proxy means tests are used for targeting social programs, the weights on different household characteristics and the qualification thresholds are set in an arbitrary fashion. However, for our application, the weights are determined by a regression of squared electricity consumption on household characteristics, and the results can be directly interpreted as a measure of the household's willingness to pay for electricity.

Another appealing aspect of the methodology is that the predicted squared consumption may even be negative. In that case, the fixed charge assigned to the household would be negative. This result may occur for households with observable characteristics that are correlated with extremely low electricity consumption. Such households have low willingness-to-pay for electricity—in which case, assigning a zero or negative fixed charge is appropriate.

We illustrate the methodology by presenting results for regressions of logged electricity consumption (Table 4) and squared electricity consumption (Table 5) on household characteristics. In both tables, columns 1 and 2 only use dwelling characteristics such as the dwelling size (number of rooms and number of bedrooms), dwelling type and ownership status, access to services, and construction materials. This choice of variables reflects the information that may be available to utilities in Colombia through the cadastral database. The results in columns 3 and 4 add household characteristics including the number of household members, the income per capita, and appliance holdings. This level of detail would be more complicated and expensive to obtain.

From the dwelling-level regression results in Table 4, we see that electricity consumption is lower at higher altitudes. Increasing the altitude by 1000 meters, all else being equal, leads to a 25 percent reduction in electricity consumption.[8] Larger dwellings use more electricity: each additional room increases electricity consumption by about 5 percent. Electricity consumption is lower in rental properties. Column 2 adds municipality fixed effects so that all of the estimates are based on within-municipality variation in the regressors. In that specification, there is a negative and statistically significant effect for apartments on electricity consumption.

Adding the household-level variables (Columns 3 and 4) reduces the magnitude of the dwelling size coefficients. An additional household member is predicted to increase electricity consumption by 5 percent (Column 4). Electricity consumption is higher for households with higher income. All of the appliance ownership variables are positive and statistically significant. The appliances that have the largest effect on electricity consumption are fridges and air conditioners. Adding a fridge to a household (changing the fridge indicator from 0 to 1) is predicted to increase electricity use by 26 percent. The effect for air conditioners is 35 percent.

The sign of the coefficients for the regressions of squared consumption on household characteristics (Table 5) are similar to those shown in Table 4. Squared consumption is higher for larger dwellings and owner-occupied dwellings. It is also higher when there are more household members and for higher-income households (Column 4). For the appliance indicators, only the effects for air conditioning, desktop computers, and

[8]For the regression $\log(y_i) = \alpha + \beta x_i + \varepsilon_i$, a one-unit increase in x_i increases the predicted value of y_i by $100(\exp(\beta) - 1)$ percent.

microwaves are statistically significant in the regression with municipality fixed effects. Air conditioning ownership has an especially large effect on squared consumption.

Our subsequent analysis of fixed charge allocation is based on regressions in which every coefficient is interacted with an indicator for the distribution firm. That is, there are 22 coefficients for the "fridge" variable, one for each distribution region, and so on. This approach is almost the same as running a separate regression for each distributor—this is what would be done in practice if the distributors were in charge of the fixed cost allocation for their customers. We do not report these results, given that the full model includes hundreds of different coefficients.

4.4 Results for Targeted Fixed Charges

Figure 31 shows the result of setting fixed charges to zero for the households receiving subsidized health insurance. Unlike the case of equal fixed charges for everyone, households in all income deciles are at least slightly better off on average. High-income households are still better off, but not by as much as when fixed costs are divided equally for everyone. Nonetheless, the average effects hide a lot of within-decile heterogeneity. Under the existing tariff, many low-income households pay an electricity price below social marginal cost. Switching to the efficient tariff leaves them worse off, even if they pay no fixed charge.

The other targeting mechanism sets the fixed charge based on each household's share of predicted squared consumption (Figure 32). Compared to the baseline of equal fixed charges, this methodology reduces the gain in consumer surplus for high-income households and reduces the loss in consumer surplus for low-income households. However, households in the bottom half of the income distribution are worse off on average, compared to the status quo tariff.

We consider alternative metrics for evaluating the targeting mechanisms (Table 6). Each row in the table represents a different allocation method. Figures 31 and 32 correspond to the third and fourth rows of the table. The first column of results shows the mean change in consumer surplus over all households. Except for the first row, the only difference between the mechanisms is the allocation of the fixed charges. This means that mean change in consumer surplus is identical—and equal to the avoided deadweight loss from inefficient pricing in Table 1.

The second column of the table shows the percentage of households who would receive negative surplus from having an electricity connection, after the change to the economically efficient tariff. This is a relevant metric because the households with negative surplus would prefer to disconnect from the grid rather than pay for a connection they do not value. The energy regulator may wish to avoid creating a situation where significant numbers of electricity consumers want to disconnect. For the existing average cost tariff, with no fixed charge, every household in Colombia receives positive consumer surplus from their electricity connection.

It is difficult to have an efficient tariff that does not leave any household with negative surplus. However, the allocation mechanism that performs best is the assignment of fixed charges based on the share of predicted squared consumption (row 4). This approach does well because of the explicit link between the fixed charge and the expectation of the household's willingness-to-pay for electricity. Tying the fixed charges to the health insurance subsidies performs badly on this metric (row 3). There are more than three times as many households who would want to disconnect than under the predicted squared consumption mechanism. This is because there are households with low willingness-to-pay for electricity who do not qualify for the health insurance subsidies, who would be allocated a larger share of fixed costs than under the system of equal fixed charges for everyone (row 2).

The third column of results in Table 6 shows the percentage of households who would be worse off under the new tariff that under the existing tariff. Even though the new tariffs create an increase in mean consumer surplus, the majority of households would be worse off, for every allocation mechanism. This discouraging result is a consequence of the skewed distribution of electricity consumption (Figure 7). Under average cost pricing, a small number of households with high electricity consumption pay a disproportionate share of fixed costs. Reallocating these costs across the entire consumption distribution will inevitably leave many households worse off.

We can capture the benefits of both targeting approaches by combining them into a single mechanism. This method would continue to set fixed charges to zero for the households receiving subsidized health insurance, but would assign the fixed charges for the remaining households based on their share of predicted squared consumption. The mean change in consumer surplus is fairly flat across the entire income distribution (Figure 33). On average, decile 10 households still do best, but the difference between decile 1 and decile 10 is less than $2 per household per month. This methodology also leaves the smallest share of households worse off than under the existing tariff (final column in Table 6). It has less than half the number of households who would want to disconnect, compared to the targeting using the health insurance eligibility alone.

The results for the mechanism in Figure 33 are primarily of academic interest. The targeting analysis relies on access to household-level information that is unlikely to be available for a real-world implementation. Figure 34 shows the results for a feasible mechanism. The estimation of the predicted consumption squared to based only on observable characteristics of the dwelling that electricity distributors in Colombia may have available (see Columns 1 and 2 of Table 5). This restriction of the information that can be used for targeting the fixed charges means that the differences between the decile 10 and decile 1 households is much larger in Figure 34 than in Figure 33. The constrained mechanism also performs slightly worse at avoiding households with negative consumer surplus (Table 6). However, the difference in outcomes between the Figures 33 and 34 is relatively small, and the additional cost of collecting household-level characteristics is unlikely to be worthwhile compared to just using dwelling information.

An important lesson from these results is that the transition to an efficient pricing mechanism for residential electricity in Colombia will be challenging to implement in a way that is politically feasible. The difficulty is that the current tariff structure is particularly favorable for low-income households with low electricity consumption, who pay no fixed charges and a variable charge set below the marginal cost of providing the service. Their price per kWh will necessarily rise under the efficient tariff. This means that even if they do not pay a fixed charge under the new tariff, they will be worse off because of the higher price per kWh. The only way for the low-income households to stay equally well off under the efficient tariff will be to set a negative fixed charge, which amounts to an allocation of "free" electricity consumption at marginal cost.

Conversely, high-income households will benefit greatly from a transition to an efficient tariff. Their electricity consumption is high and they pay a price per kWh that is many times higher than the marginal cost. The reduction in their variable charge will leave them better off, even if they have to pay a relatively high fixed charge with the new tariff.

5 Conclusion

In this paper, we showed that the residential electricity prices in Colombia—based on an average cost, increasing block tariff—create both short-run and long-run distortions in household energy decisions. For the Colombian government, the subsidy component of the prices is a significant and growing fiscal burden. The tariff distortions are more salient than before because of new technologies for the production and consumption of electricity, particularly residential rooftop solar and electric vehicles. The still-nascent market for these technologies makes this a propitious time to reevaluate the electricity tariff structure.

We propose a potential path for improving the efficiency of electricity pricing in Colombia. Reducing the price per kilowatt-hour and introducing fixed charges will enhance the economic efficiency of the tariffs. In a middle-income country, where there is a substantial heterogeneity in income and electricity consumption, charging the same fixed charge for all households may leave many households with low electricity consumption worse off than they would be with no connection at all. Our proposal to vary the fixed charge by household, based on a prediction model for the household's willingness-to-pay for electricity, would considerably reduce this concern. It is also feasible to implement given the information available to electricity suppliers in Colombia.

Our proposed tariff reforms would have different effects on the rooftop solar and electric vehicle markets in Colombia. Lower per-unit prices for electricity consumption, especially for high-income households, would boost the future development of the electric vehicle market as battery technologies improve and vehicle prices fall. However, we also showed that switching to an efficient tariff would lead to a reduction in residential solar adoption at high panel prices. This is a feature, not a bug, of the proposed tariff reform. Social welfare is not enhanced by households who install solar because of the high prices they pay under a distortionary electricity tariff. The social value of the electricity produced by their panels is less than the cost of installation, even after accounting for the avoided externalities from conventional electricity generation.

A two-part tariff, with a marginal price linked to the wholesale cost of electricity generation, would also enhance the ability of the Colombian electricity market to cope with periodic shortfalls in hydro inflows. During years with high rainfall, households would pay low prices for electricity. During El Niño years, households would pay high prices—creating an incentive for conservation. The existing tariffs change little between wet and dry years, leading to ad hoc interventions to encourage conservation when water levels are low.

Our results on the distributional effects of the proposed tariff reform suggest that it will not be possible to make everyone better off under the new tariffs. This is an inevitable consequence of the inefficiencies in the existing tariff, in which payments by some households do not even cover the marginal cost of supplying electricity. Keeping the existing tariffs will not make this problem disappear. It will get worse over time. Despite the short-term costs for some households, reforming the electricity pricing system will produce substantial long-term economic and environmental benefits for Colombia.

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Table 1: Deadweight loss from non-marginal-cost electricity pricing, by stratum and demand assumption, in US$ per household per month

Stratum	Cons elast -0.15	Cons elast -0.3	Lin, elast -0.15	Lin, elast -0.3
1	0.31	0.65	0.25	0.51
2	0.35	0.71	0.27	0.55
3	0.48	0.99	0.38	0.75
4	0.71	1.48	0.56	1.11
5	1.22	2.55	0.90	1.79
6	1.77	3.68	1.32	2.65

Notes: Each row shows the mean deadweight loss, in US$ per household per month, for all households in that stratum. The columns correspond to different assumptions on the demand function (linear or constant elasticity) and the calibrated price elasticity (-0.15 or -0.30).

Table 2: Deadweight loss from non-marginal-cost electricity pricing, by stratum and demand assumption, as a percentage of household electricity expenditure

Stratum	Cons elast -0.15	Cons elast -0.3	Lin, elast -0.15	Lin, elast -0.3
1	2.6	5.3	2.1	4.2
2	2.3	4.7	1.8	3.6
3	2.1	4.4	1.7	3.4
4	2.2	4.6	1.7	3.5
5	3.4	7.2	2.5	5.1
6	3.2	6.6	2.4	4.8

Notes: See Table 1. The deadweight loss in this table is expressed as a percentage of household electricity expenditure in each stratum.

Table 3: Percentage of Colombian households for whom rooftop solar adoption would be feasible and profitable, for different solar panel prices and discount rates

Panel price	Discount rate	System size, for existing tariff			New tariff
(US$/kW)	(%)	1 kW	2 kW	3 kW	
500	2.5	31.4	31.4	31.4	31.4
1,000	2.5	31.4	31.4	31.4	31.4
1,500	2.5	30.8	30.2	29.9	31.3
2,000	2.5	21.8	17.8	15.1	26.9
2,500	2.5	15.7	11.2	7.9	15.1
3,000	2.5	12.7	7.3	4.5	3.6
3,500	2.5	10.0	4.9	2.5	0.1
4,000	2.5	7.1	3.1	1.5	0.0
500	5.0	31.4	31.4	31.4	31.4
1,000	5.0	31.2	31.1	31.2	31.4
1,500	5.0	21.3	17.0	14.3	26.2
2,000	5.0	14.2	9.2	6.0	10.0
2,500	5.0	10.4	5.3	2.8	0.4
3,000	5.0	6.5	2.8	1.3	0.0
3,500	5.0	2.0	0.7	0.3	0.0
4,000	5.0	0.3	0.1	0.0	0.0
500	10.0	31.4	31.4	31.4	31.4
1,000	10.0	18.9	14.3	11.2	21.8
1,500	10.0	10.9	5.7	3.1	0.7
2,000	10.0	3.8	1.4	0.6	0.0
2,500	10.0	0.2	0.1	0.0	0.0
3,000	10.0	0.0	0.0	0.0	0.0
3,500	10.0	0.0	0.0	0.0	0.0
4,000	10.0	0.0	0.0	0.0	0.0

Notes: Each cell shows the percentage of Colombian households who are eligible for solar (owner-occupied housing) and for whom the net present value of installing solar is positive, for the assumed solar panel price and real discount rate in that row. Present values are calculated assuming a 30-year panel life. For the existing retail electricity tariffs, results for three panel sizes are shown: 1 kW, 2 kW, and 3 kW. For the counterfactual tariffs, assuming surplus generation can be sold back at the marginal cost tariff, the adoption decision is independent of the panel size.

Table 4: Estimation results for logged electricity consumption on dwelling and household characteristics

	(1)	(2)	(3)	(4)
Municipality elevation (000 m)	-0.29^{***}		-0.20^{***}	
	(0.04)		(0.03)	
Number of rooms	0.05^{***}	0.06^{***}	0.02^{***}	0.03^{***}
	(0.01)	(0.01)	(0.005)	(0.004)
Number of bedrooms	0.10^{***}	0.08^{***}	0.03^{**}	0.03^{**}
	(0.02)	(0.02)	(0.01)	(0.01)
Apartment (0/1)	0.001	-0.02^{*}	-0.01	-0.02^{***}
	(0.03)	(0.01)	(0.02)	(0.01)
Non-owner-occuped (0/1)	-0.10^{***}	-0.09^{***}	-0.07^{***}	-0.06^{***}
	(0.01)	(0.01)	(0.01)	(0.01)
Household members			0.07^{***}	0.05^{***}
			(0.005)	(0.005)
Income per capita (US$000)			0.05^{***}	0.06^{***}
			(0.01)	(0.02)
Fridge (0/1)			0.23^{***}	0.23^{***}
			(0.02)	(0.01)
Washing machine (0/1)			0.08^{***}	0.07^{***}
			(0.01)	(0.01)
Water heater (0/1)			0.14^{***}	0.06^{***}
			(0.02)	(0.01)
Air conditioning (0/1)			0.44^{***}	0.30^{***}
			(0.03)	(0.02)
Fan (0/1)			0.17^{***}	0.05^{***}
			(0.03)	(0.01)
Television (0/1)			0.08^{***}	0.08^{***}
			(0.02)	(0.02)
Desktop computer (0/1)			0.08^{***}	0.10^{***}
			(0.01)	(0.01)
Microwave (0/1)			0.08^{***}	0.09^{***}
			(0.01)	(0.01)
Heater (0/1)			0.10^{**}	0.10^{***}
			(0.05)	(0.04)
Constant	5.03^{***}	4.53^{***}	4.37^{***}	4.05^{***}
	(0.09)	(0.08)	(0.06)	(0.03)
Municipality fixed effects	N	Y	N	Y
Wall, floor, wastewater type	Y	Y	Y	Y
Observations	66,637	66,637	66,637	66,637
Adjusted R^2	0.25	0.37	0.36	0.43

Notes: Standard errors in parentheses are clustered at the municipality level. All regressions include one dummy for wall type, three dummies for floor type, and two dummies for wastewater type that are not shown in the reported results.

Table 5: Estimation results for squared electricity consumption on dwelling and household characteristics

	(1)	(2)	(3)	(4)
Municipality elevation (000 m)	-31.36^{***}		-15.59^{***}	
	(5.80)		(4.07)	
Number of rooms	10.36^{***}	11.80^{***}	6.10^{***}	7.00^{***}
	(2.79)	(2.76)	(1.70)	(1.63)
Number of bedrooms	3.61^{*}	2.98	0.05	1.08
	(2.04)	(2.07)	(1.81)	(2.01)
Apartment (0/1)	-1.31	-3.35	-2.76	-4.15^{**}
	(5.33)	(2.94)	(3.79)	(2.10)
Non-owner-occuped (0/1)	-10.57^{***}	-8.02^{***}	-4.81^{***}	-3.80^{***}
	(2.03)	(1.51)	(1.11)	(1.00)
Household members			6.29^{***}	4.69^{***}
			(0.87)	(0.70)
Income per capita (US$000)			20.19^{**}	21.06^{**}
			(8.45)	(8.61)
Fridge (0/1)			0.74	2.72
			(1.94)	(1.83)
Washing machine (0/1)			0.04	0.79
			(1.32)	(1.37)
Water heater (0/1)			4.10	-1.26
			(5.10)	(5.52)
Air conditioning (0/1)			124.02^{***}	103.02^{***}
			(13.46)	(11.70)
Fan (0/1)			12.11^{***}	-1.43
			(2.91)	(2.41)
Television (0/1)			-0.98	0.55
			(2.30)	(2.23)
Desktop computer (0/1)			7.00^{***}	9.04^{***}
			(2.02)	(2.13)
Microwave (0/1)			15.03^{***}	16.33^{***}
			(3.43)	(3.78)
Heater (0/1)			12.22	12.68
			(10.18)	(9.27)
Constant	50.89^{***}	-12.01	2.45	-29.16^{***}
	(10.91)	(12.34)	(6.16)	(9.78)
Municipality fixed effects	N	Y	N	Y
Wall, floor, wastewater type	Y	Y	Y	Y
Observations	66,637	66,637	66,637	66,637
Adjusted R^2	0.06	0.11	0.15	0.17

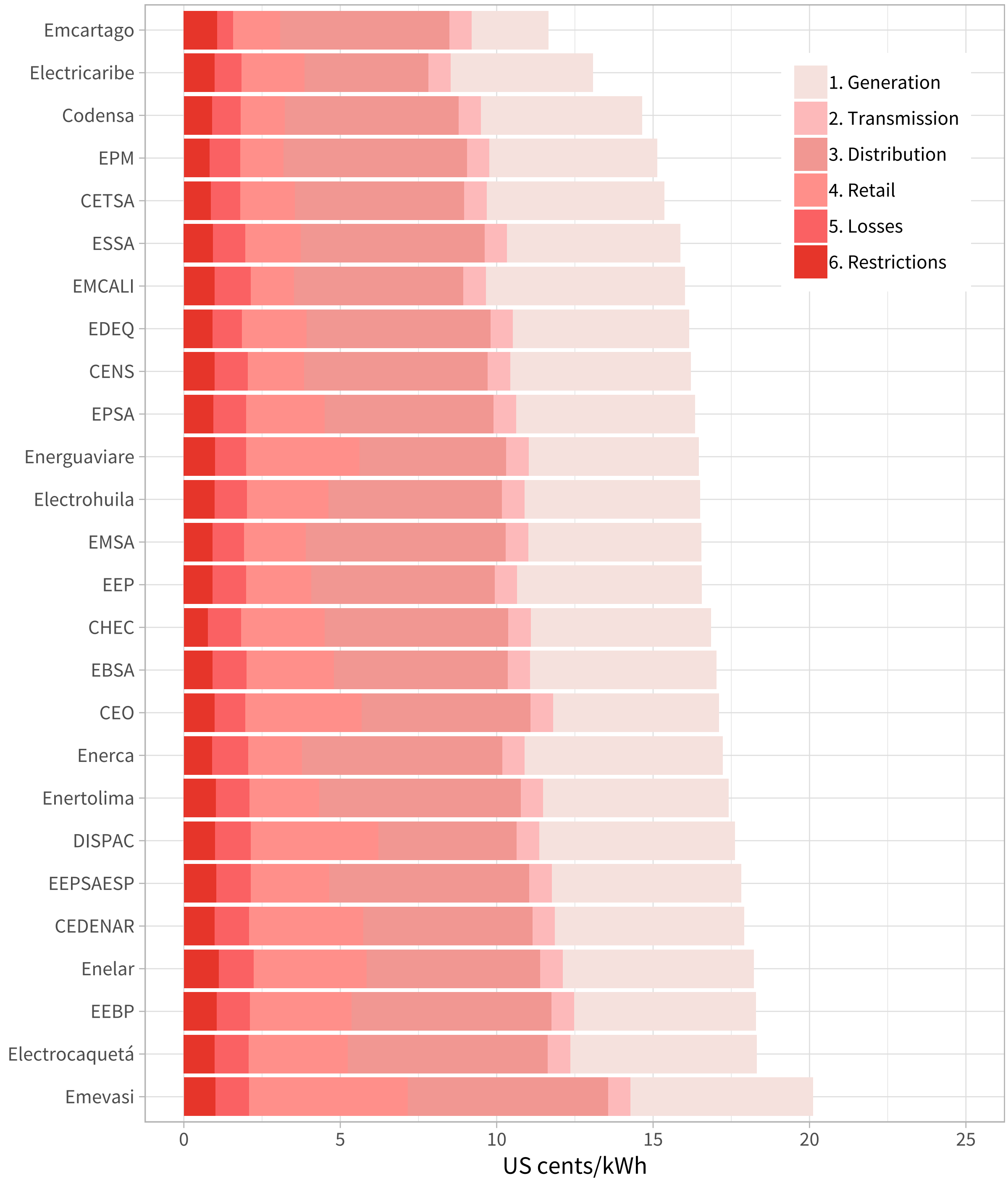
Notes: Dependent variable is the square of monthly electricity consumption, divided by 1000. Standard errors in parentheses are clustered at the municipality level. All regressions include one dummy for wall type, three dummies for floor type, and two dummies for wastewater type that are not shown in the reported results.

Table 6: Summary of results for alternative mechanisms to allocate fixed charges

Fixed charge allocation mechanism	$CS_1 - CS_0$	$\mathrm{I}(CS_1 < 0)$	$\mathrm{I}(CS_1 < CS_0)$
No subsidy transfer	-5.71	20.39	83.06
Equal fixed charges	0.97	2.99	62.16
Zero fixed charges for SISBEN	0.97	3.20	53.64
Use predicted Q^2 for household	0.97	1.05	58.60
Zero SISBEN + predicted Q^2 for household	0.97	1.41	51.79
Zero SISBEN + predicted Q^2 for dwelling	0.97	1.88	52.54

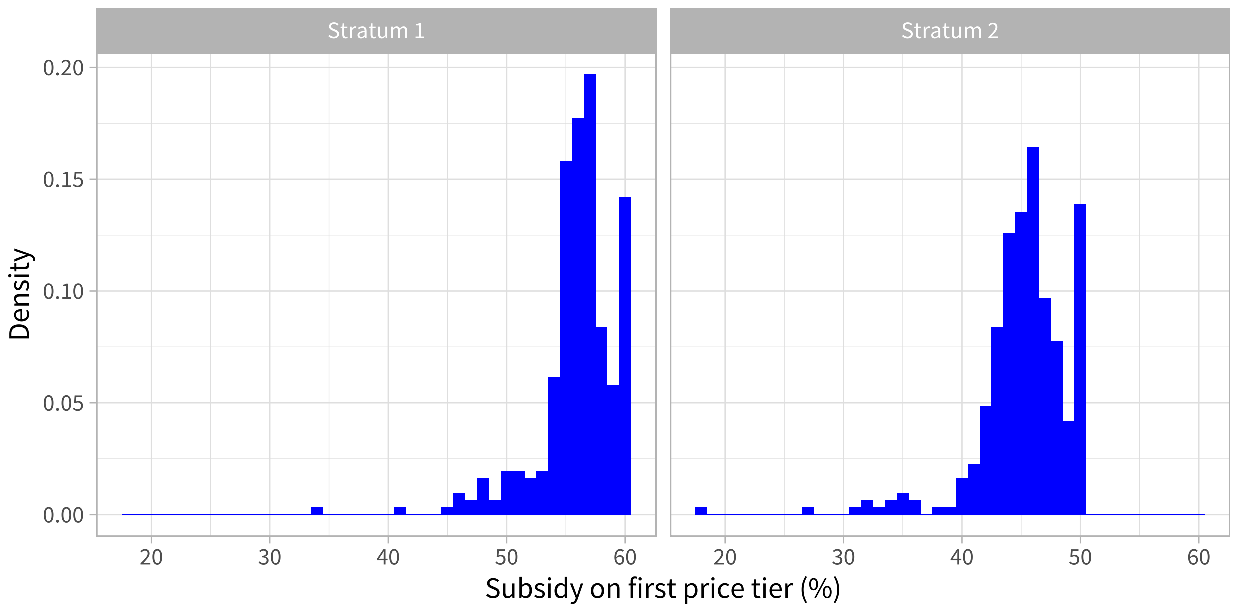
Notes: Each row shows the summary results for an alternative mechanism for allocating fixed charges and corresponds to the distributional results shown in Figures 29 to 34. The footnotes to those figures describe each mechanism. The first column of results shows the mean change in consumer surplus across all households for that mechanism. The second column shows the percentage of households under that mechanism with negative consumer surplus, who may find it optimal to disconnect from the grid. The final column shows the percentage of households with lower consumer surplus under the mechanism than under the current tariff.

Figure 1: Components of retail electricity tariffs in the Colombian market in June 2017, by firm



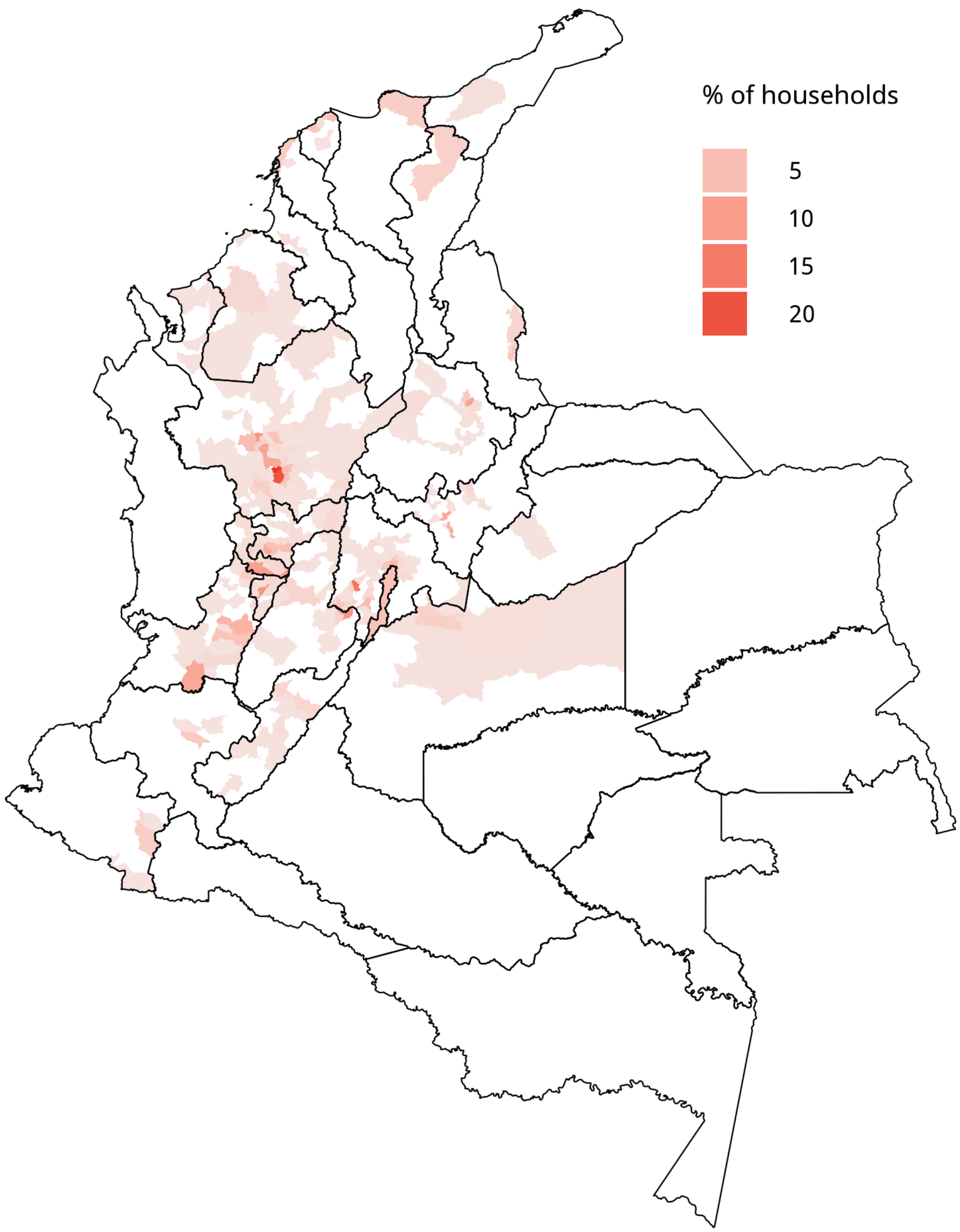
Notes: The base retail prices and its decomposition into the individual components were obtained from the tariff sheets for June 2017, downloaded from the website for each for each electricity distribution and retailing firm.

Figure 2: Distribution of first tier subsidy component for Strata 1 and 2 tariffs, July 2016–June 2017



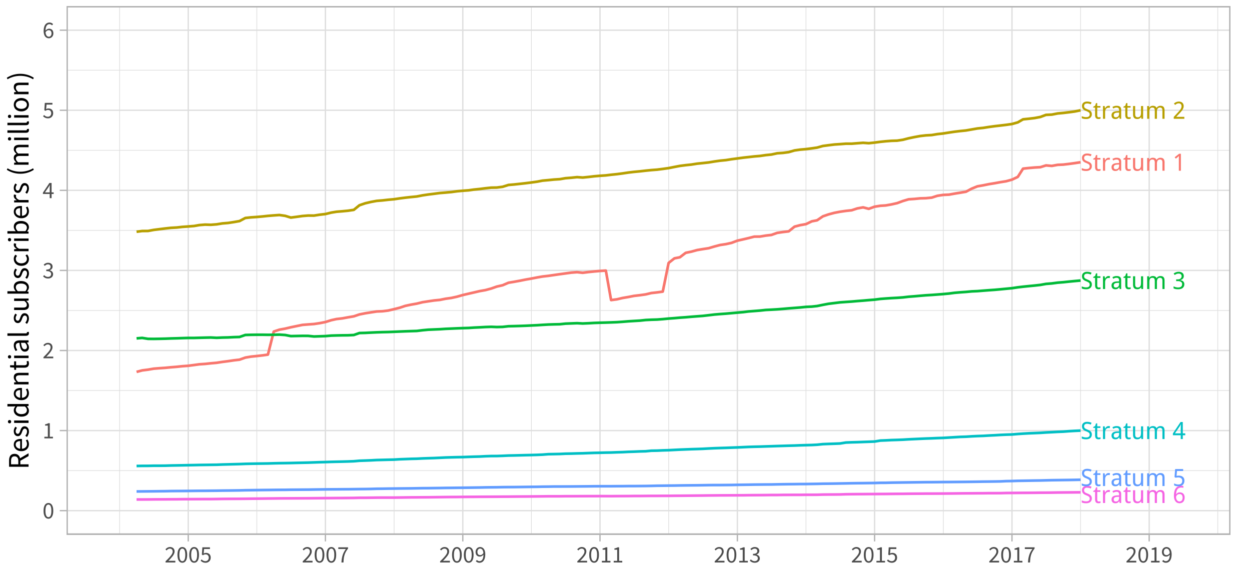
Notes: Each observation is a residential tariff schedule for one month between July 2016 and June 2017. The histogram show the distribution of the Stratum 1 and Stratum 2 subsidies for the first price tier.

Figure 3: Share of households in Strata 5 and 6, by municipality, in June 2018



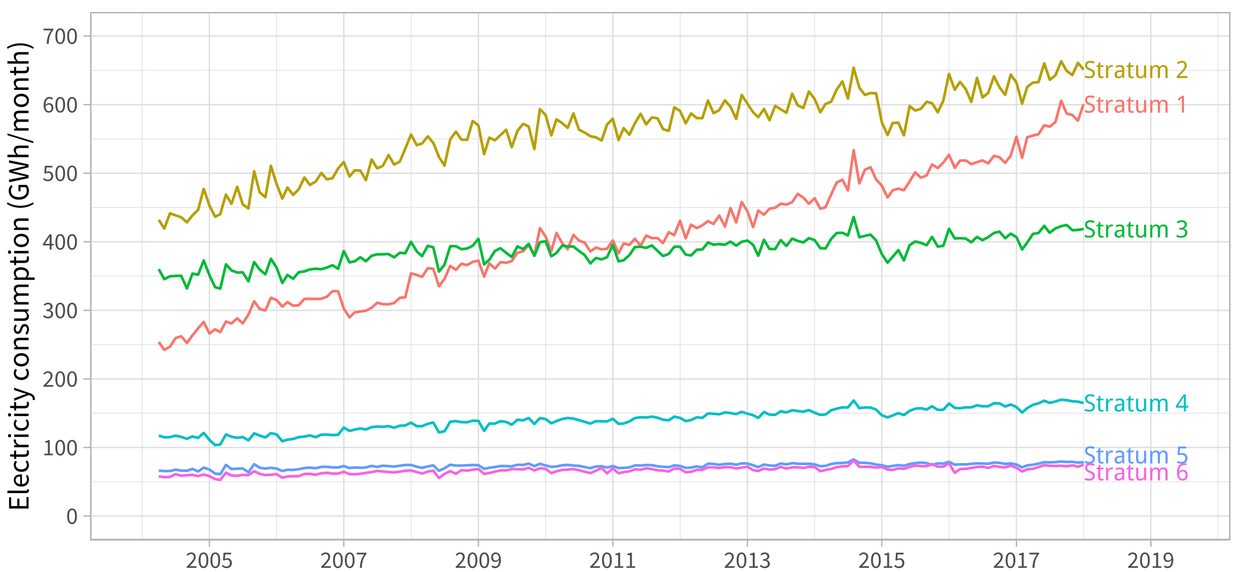
Notes: For each municipality, the map shows the share of residential electricity consumers who are classified in the highest two strata (Strata 5 and 6) and pay a 20% contribution towards the subsidized electricity tariffs.

Figure 4: Number of households classified in each stratum for the residential electricity tariff, 2004–2017



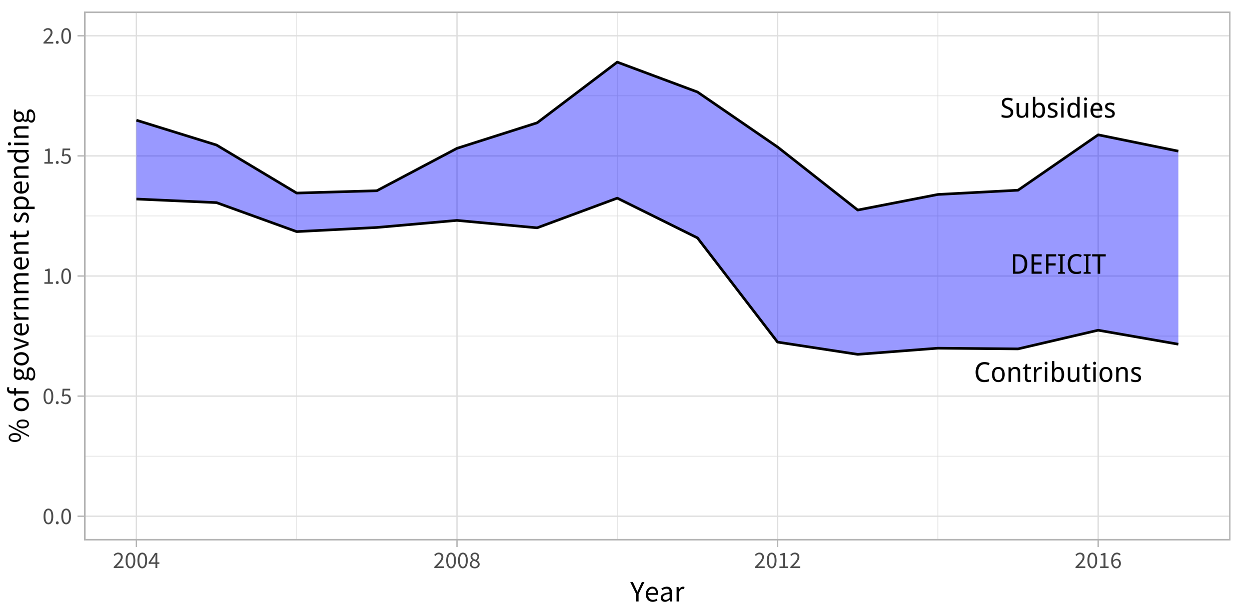
Notes: Monthly numbers of households in each stratum, by municipality and retailer, are from SUI. Missing observations are filled in using the last non-missing observation. Totals are smoothed by taking a rolling maximum with a 13-month window.

Figure 5: Aggregate monthly electricity consumption for households classified in each stratum, 2004–2017



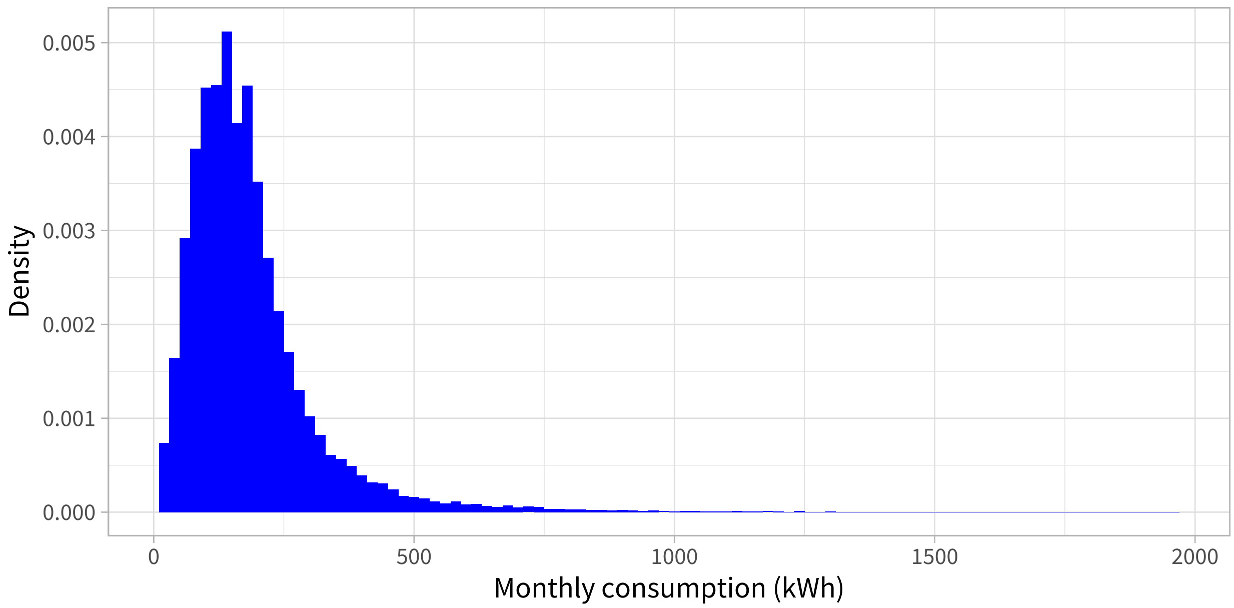
Notes: Monthly total consumption for households in each stratum, by municipality and retailer, are from SUI.

Figure 6: Subsidies and contributions in the Colombian electricity sector, 2004–2017



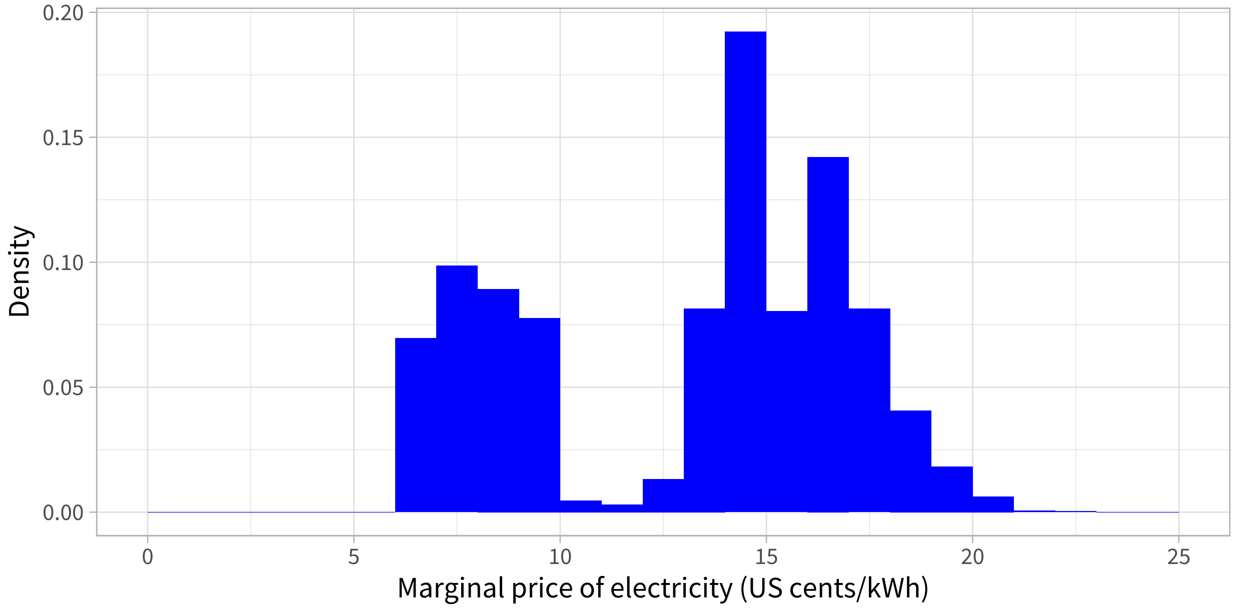
Notes: Annual subsidies and contributions are calculated from monthly distributor-level information from SUI. These are expressed as a percentage of government expenditure, using annual central government expenditure series from Banco de la República (2019). The data does not include additional subsidies for the Social Tariff, nor subsidies for off-grid generation.

Figure 7: Distribution of household electricity consumption in Colombia



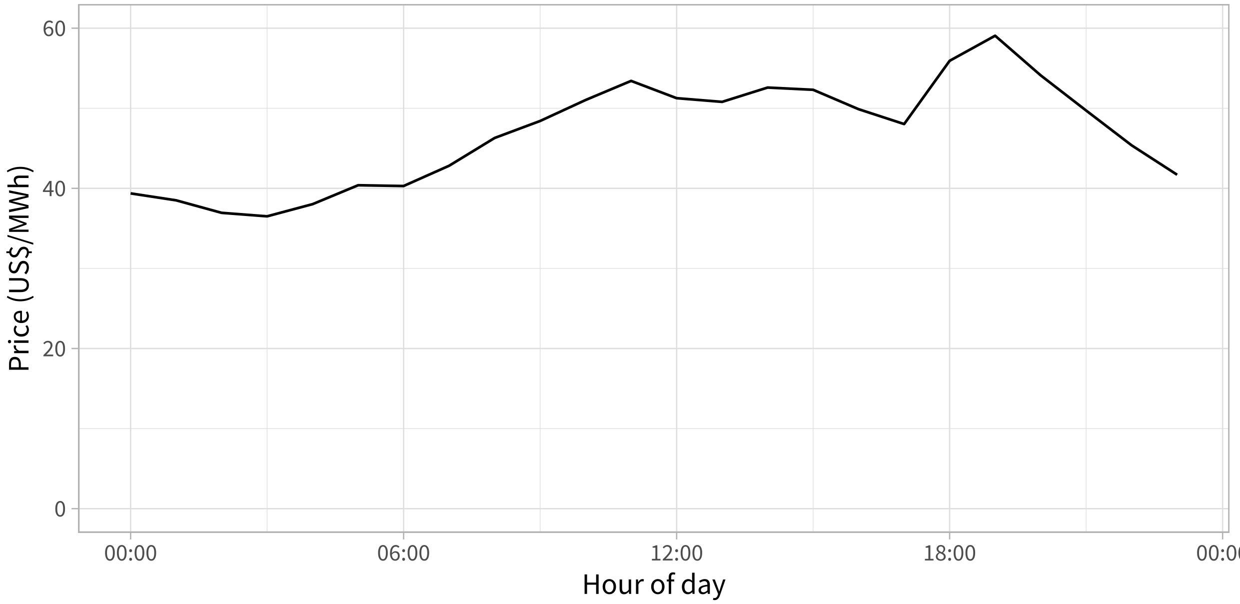
Notes: Household electricity consumption is imputed from the National Household Budget Survey, using information on the electricity expenditure for the most recent bill, combined with tariff information for the corresponding electricity distributor. Observations with consumption below 10 kWh/month or above 2000 kWh/month are dropped from the analysis.

Figure 8: Distribution of marginal electricity prices faced by households in Colombia, 2016–17



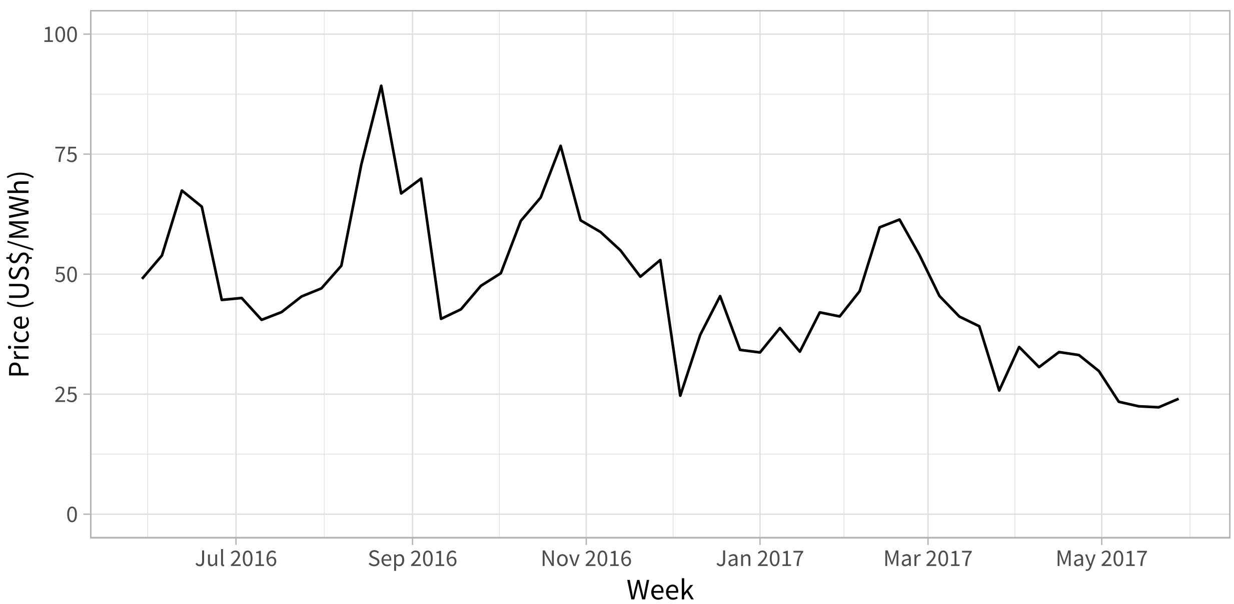
Notes: Marginal prices for each household are determined based on the household stratum, the imputed consumption from the National Household Budget Survey, and the tariff schedule from the household's electricity distributor.

Figure 9: Intraday wholesale electricity prices in the Colombian market, 2016–17



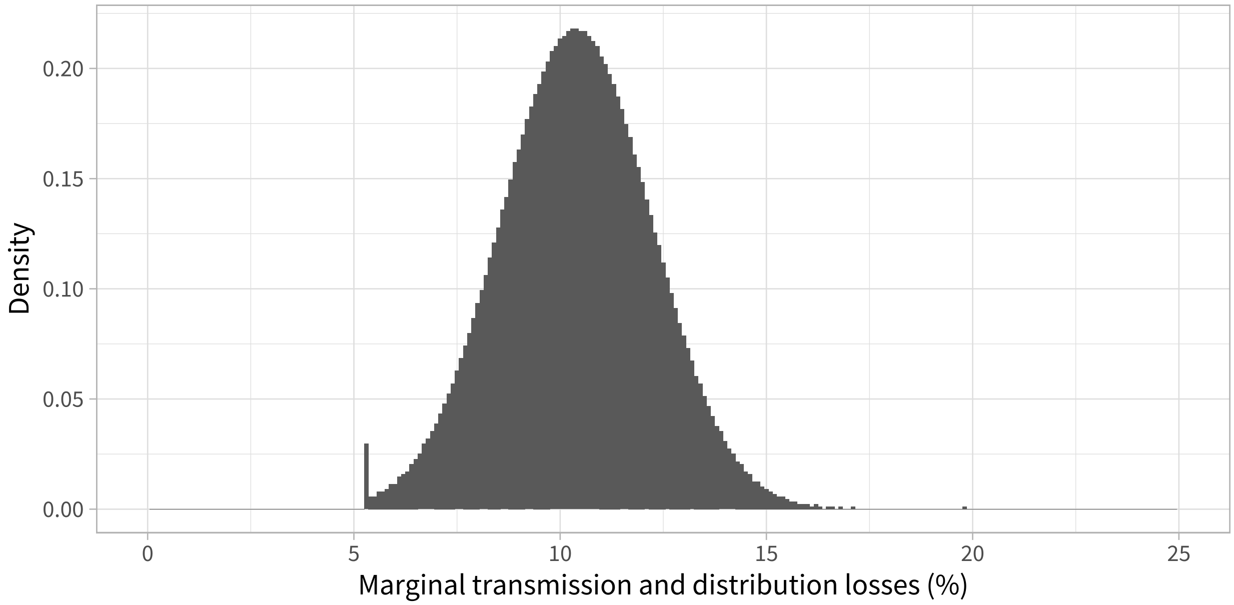
Notes: Mean electricity price in the Colombian wholesale market by hour of day, for the period June 2016 to May 2017. Price data is from XM.

Figure 10: Weekly average wholesale electricity prices in the Colombian market, 2016–17



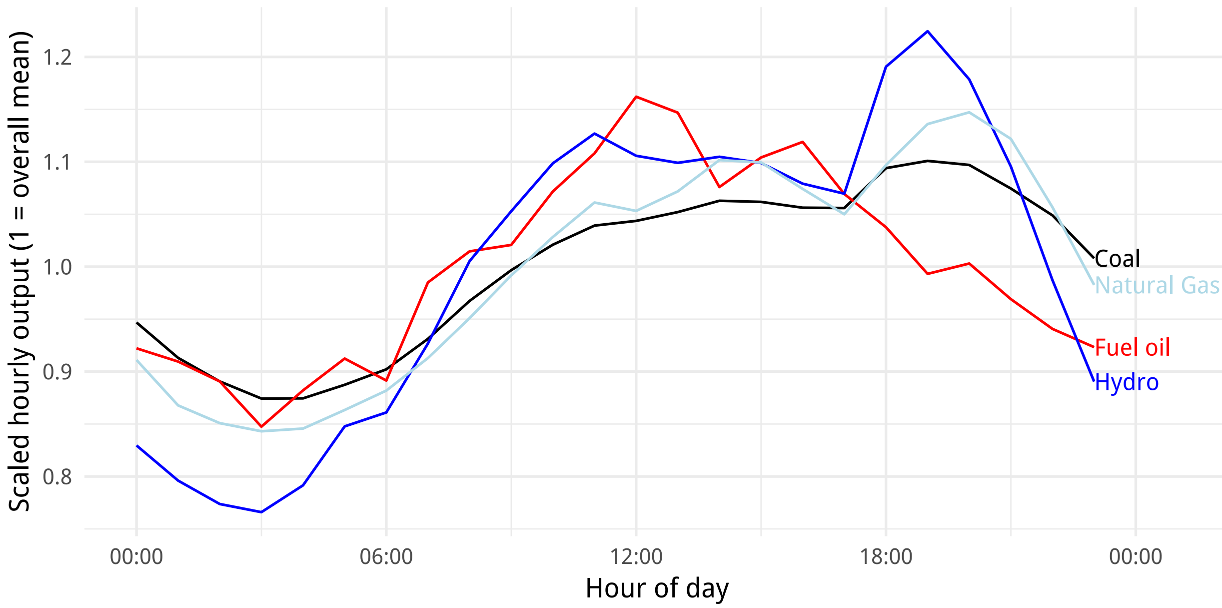
Notes: Mean electricity price in the Colombian wholesale market by week of sample, for the period June 2016 to May 2017. Price data is from XM.

Figure 11: Distribution of marginal losses in the transmission and distribution networks in Colombia



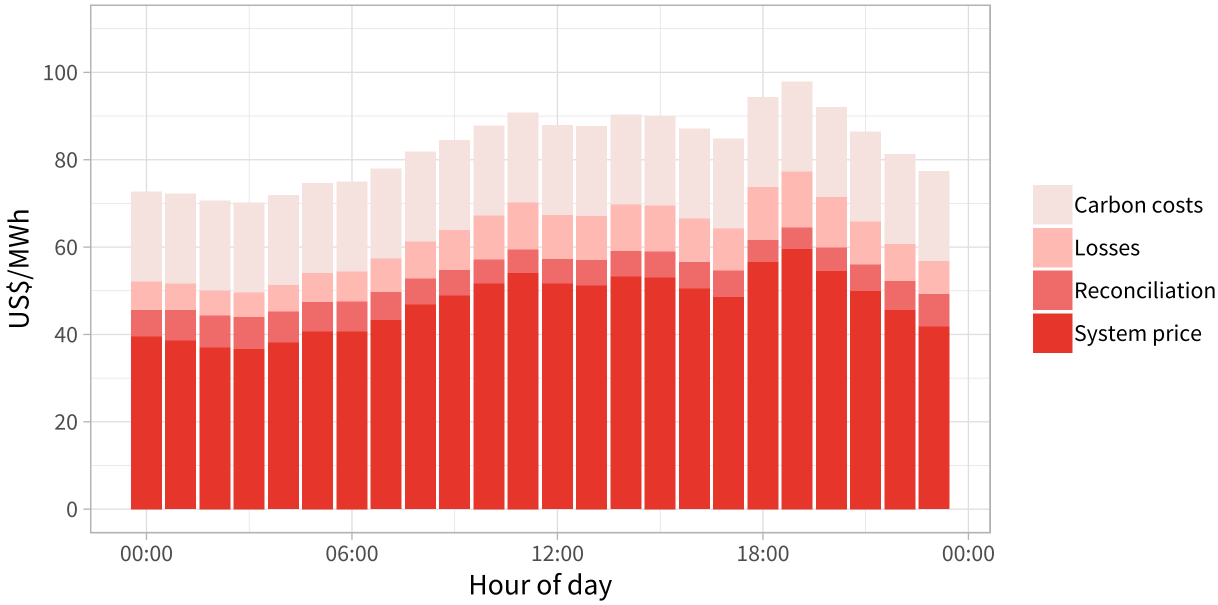
Notes: Marginal transmission losses are predicted from a regression of hourly transmission losses on a quadratic in system demand. Marginal distribution losses are taken from estimates for the United States by Borenstein and Bushnell (2018). The graph shows the distribution of the sum of the two types of losses.

Figure 12: Mean hourly generation by fuel type (scaled)



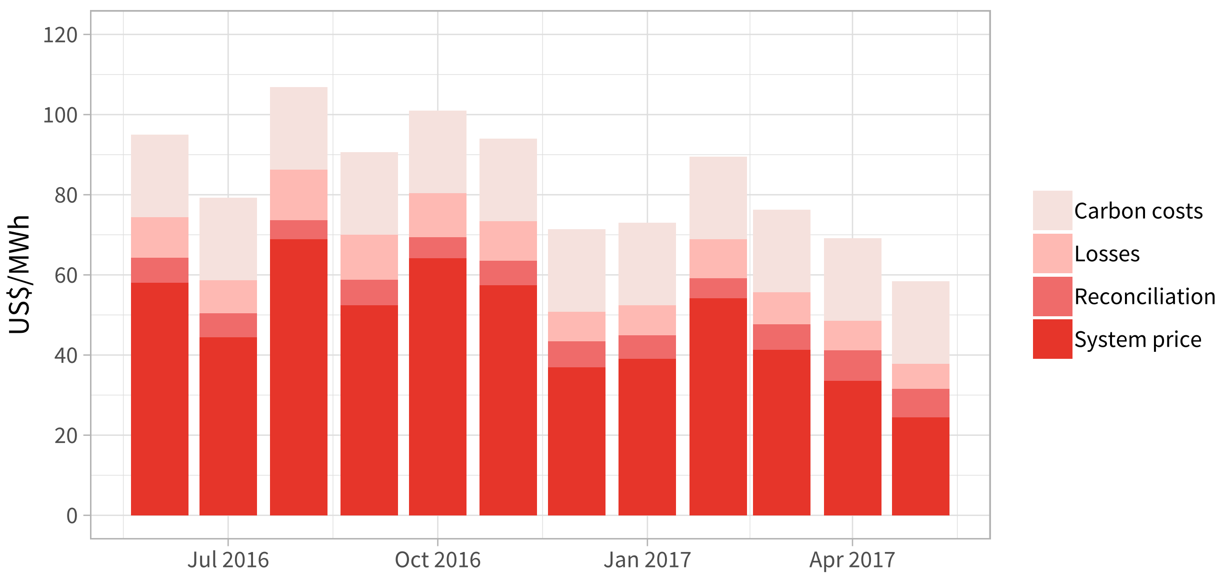
Notes: The graph shows the mean hourly output from dispatchable generation units in the Colombian electricity market, for the period June 2016 to May 2017. The mean hourly output for each technology is scaled by the overall mean output by technology.

Figure 13: Mean hourly marginal costs for electricity consumption in Colombia, June 2016–May 2017



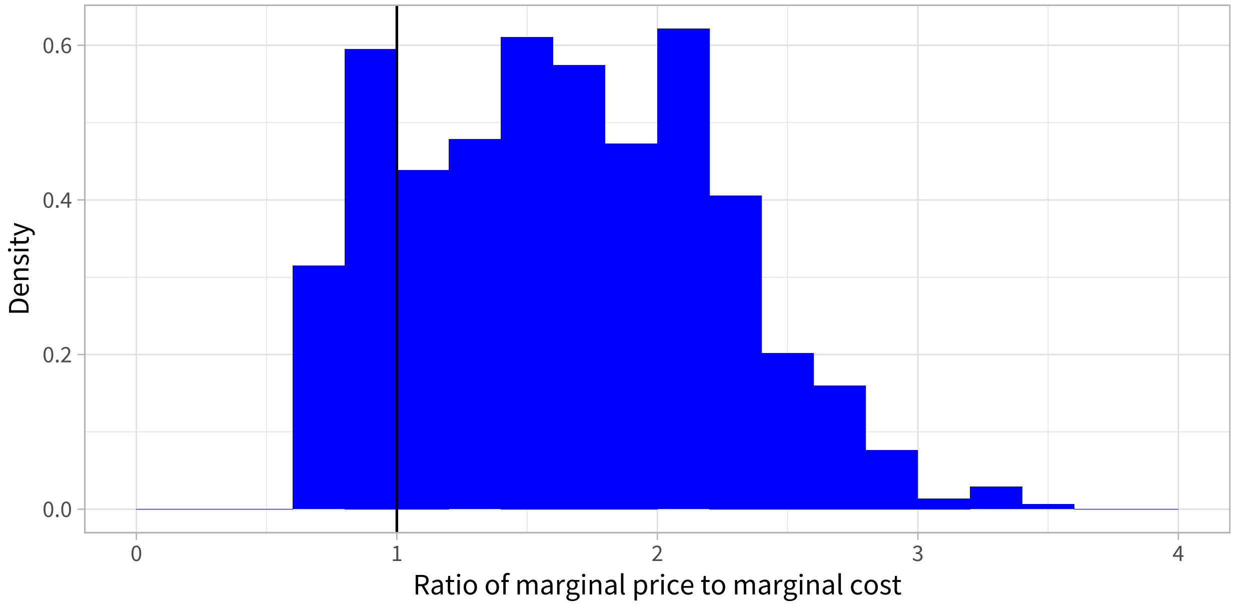
Notes: Hourly means for the year of the four components of the marginal cost of electricity, weighted by the generation in each hour.

Figure 14: Mean monthly marginal costs for electricity consumption in Colombia, June 2016–May 2017



Notes: Monthly means for the year of the four components of the marginal cost of electricity, weighted by the generation in each hour of the month.

Figure 15: Distribution of marginal electricity prices faced by Colombian households, relative to marginal costs



Notes: Distribution of the ratio of the marginal price faced by each household and the monthly mean marginal cost of consuming electricity.

Figure 16: Calculation of optimal electricity consumption and the deadweight loss from non-marginal-cost pricing

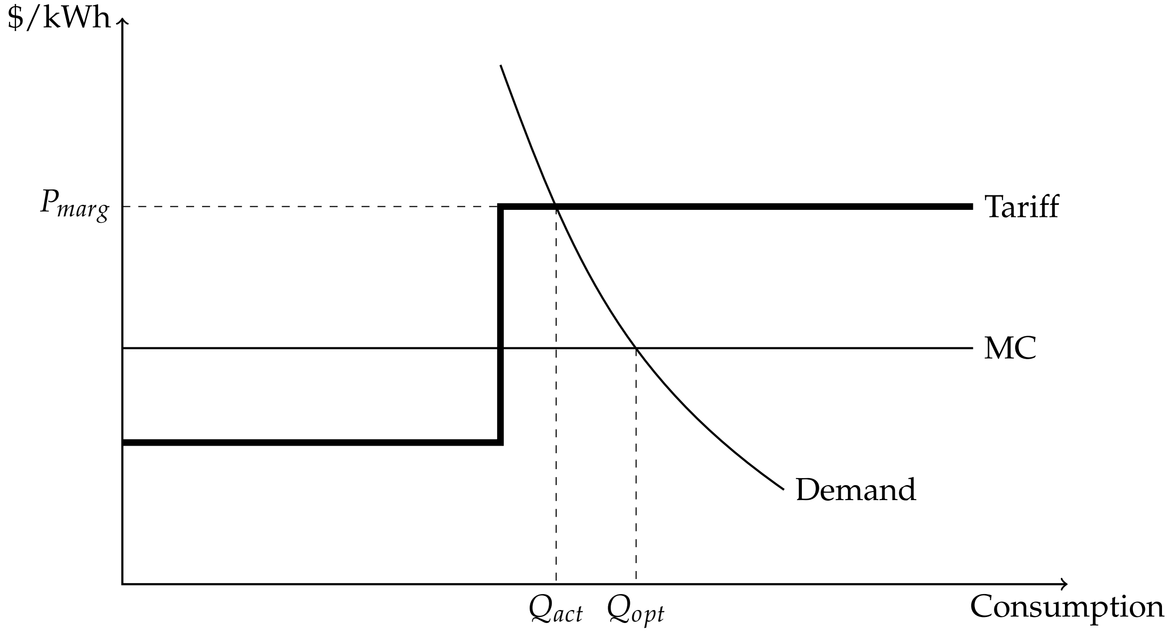
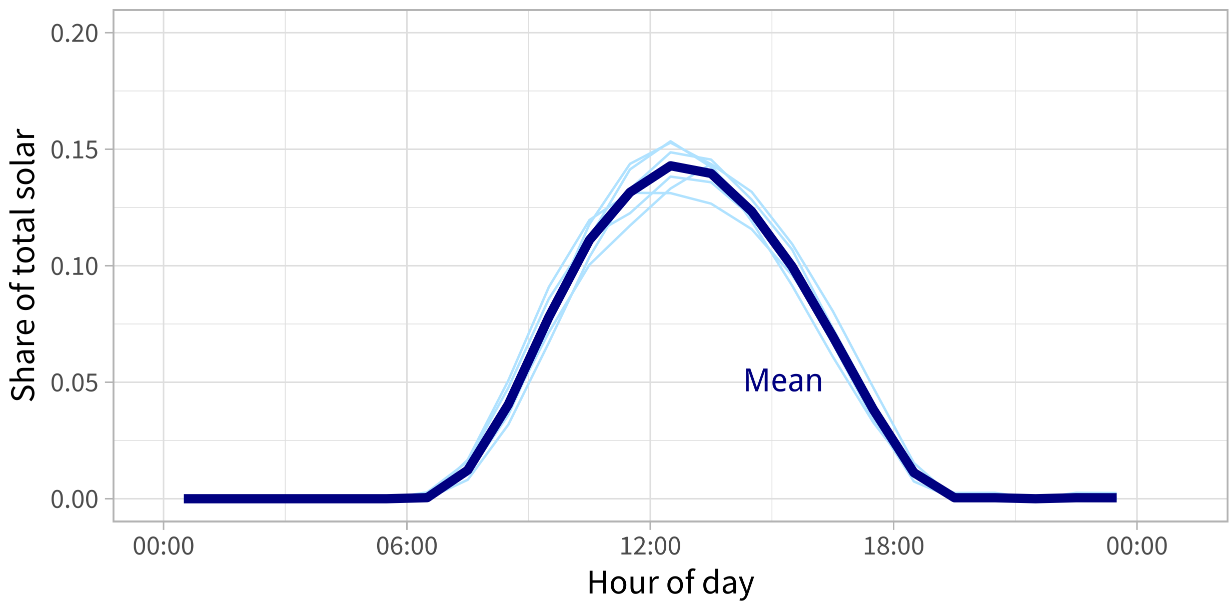
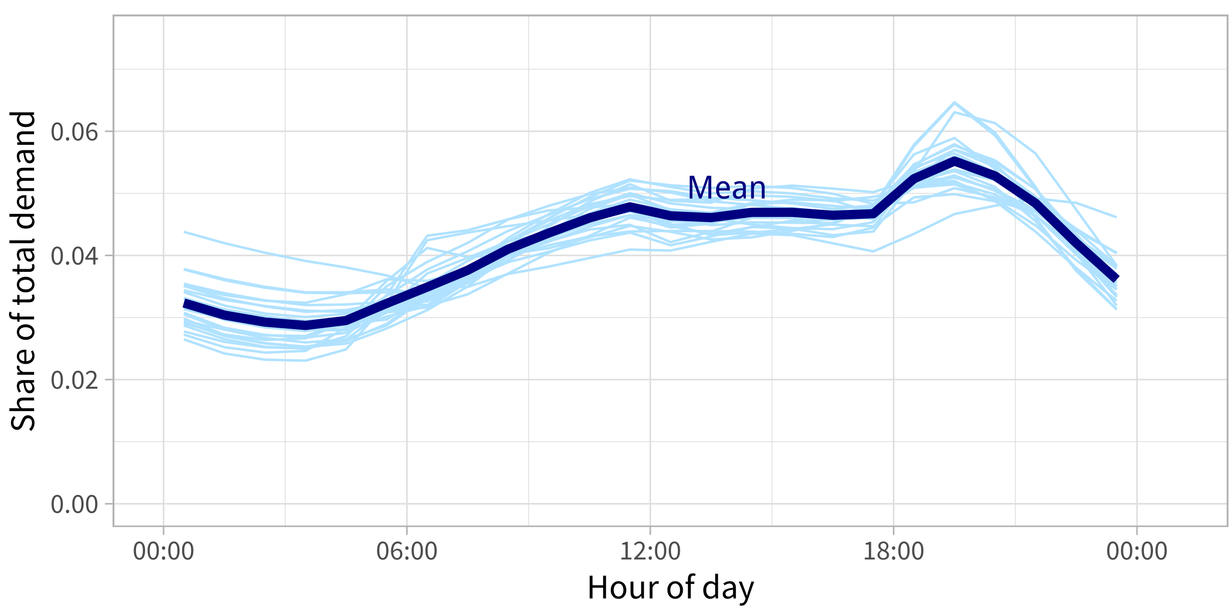


Figure 17: Mean hourly solar radiation for six locations in Colombia



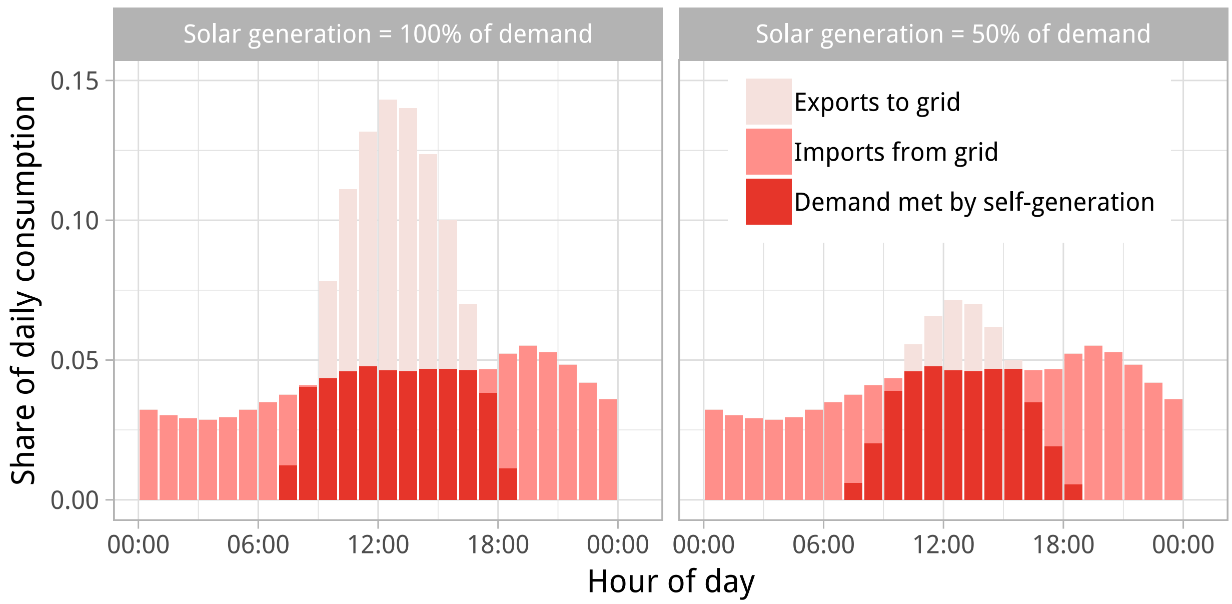
Notes: Hourly solar radiation for 2016 to 2018 is from IDEAM. The hourly means are scaled so that the daily total is 1. The locations shown are Bogotá, Calí, Barranquilla, Medellín, Villavicencio, and Bucaramanga.

Figure 18: Mean hourly demand for regulated consumers in Colombia, by retailer



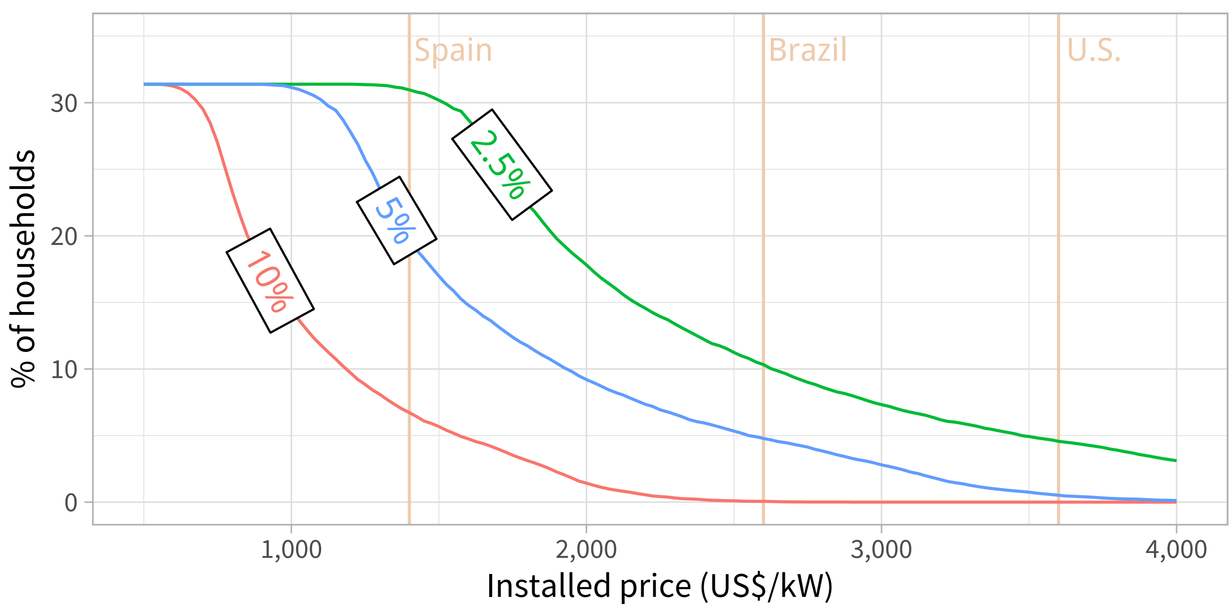
Notes: Hourly withdrawals by retailers for regulated users is from XM. The hourly means are scaled so that the daily total is 1. Electricity retailers that are not integrated with a distribution network are excluded. The thick blue line shows the mean across the retailers.

Figure 19: Calculation of hourly excess solar generation, for different levels of household generation and consumption



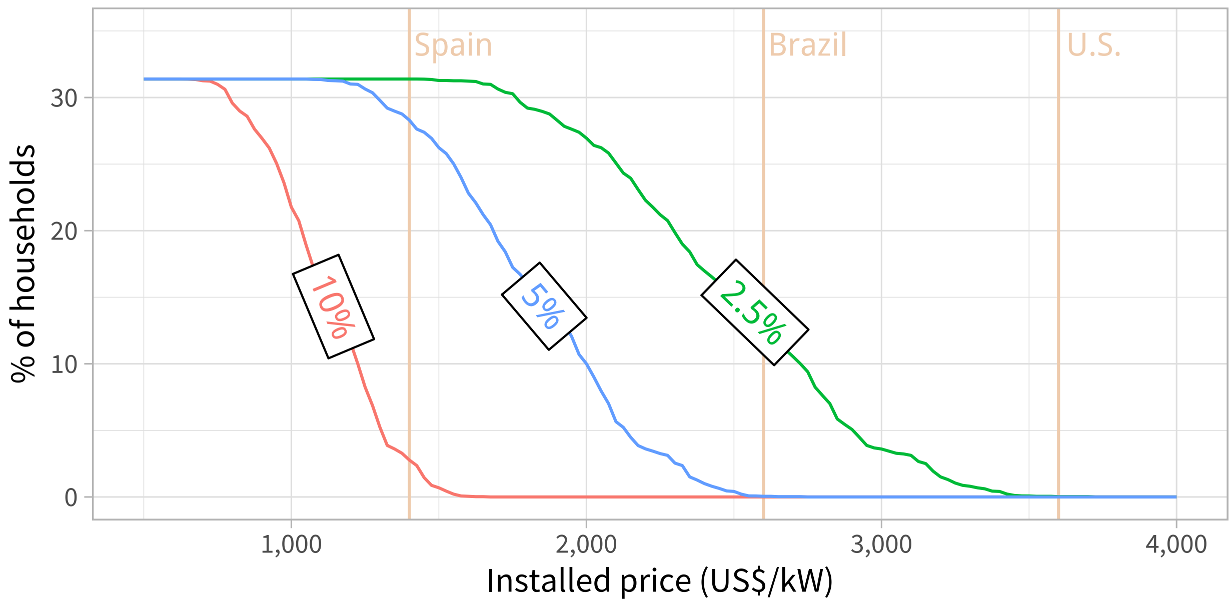
Notes: The pattern of hourly solar generation is from Figure 17 and the pattern of hourly demand is from Figure 18. The quantity of exported generation depends on the total demand relative to the total generation.

Figure 20: Optimal adoption of residential solar in Colombia under existing tariffs, for different discount rates and installation prices



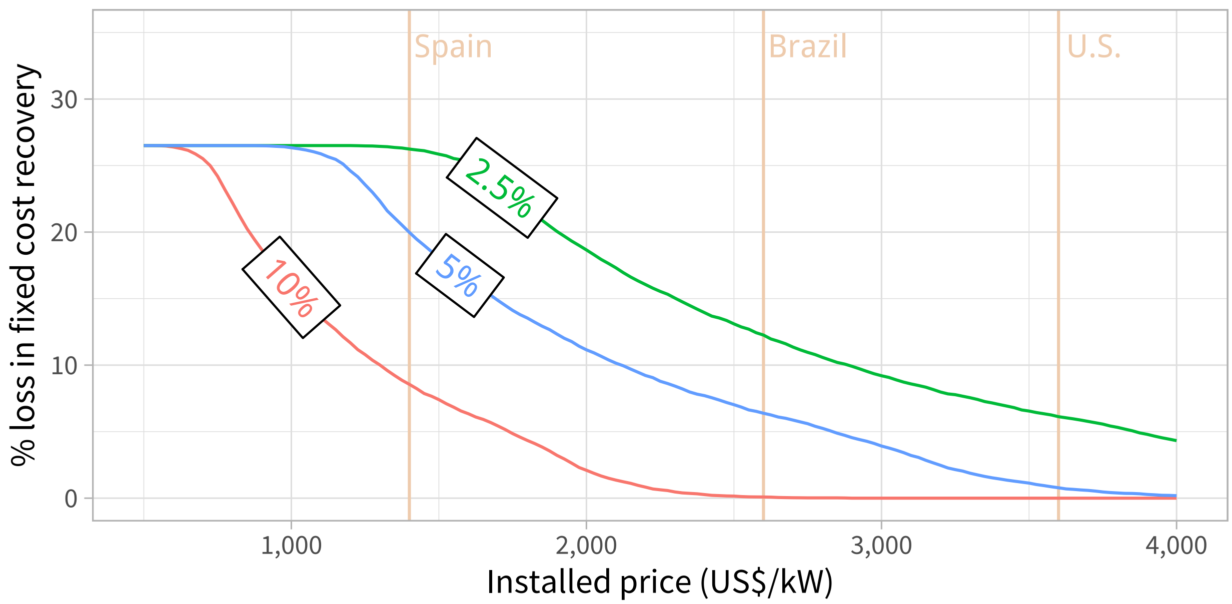
Notes: Each line shows the percentage of all households for which solar adoption would be privately optimal, as a function of the assumed installed price of solar, for a different discount rate assumption. Only owner-occupied houses with concrete or brick walls are assumed to be candidates for solar. The adoption calculation assumes the existing retail tariff structure plus the CREG Resolution 30 of 2018 payments for solar generation. A 2 kW solar installation is assumed.

Figure 21: Optimal adoption of residential solar in Colombia for counterfactual efficient tariffs



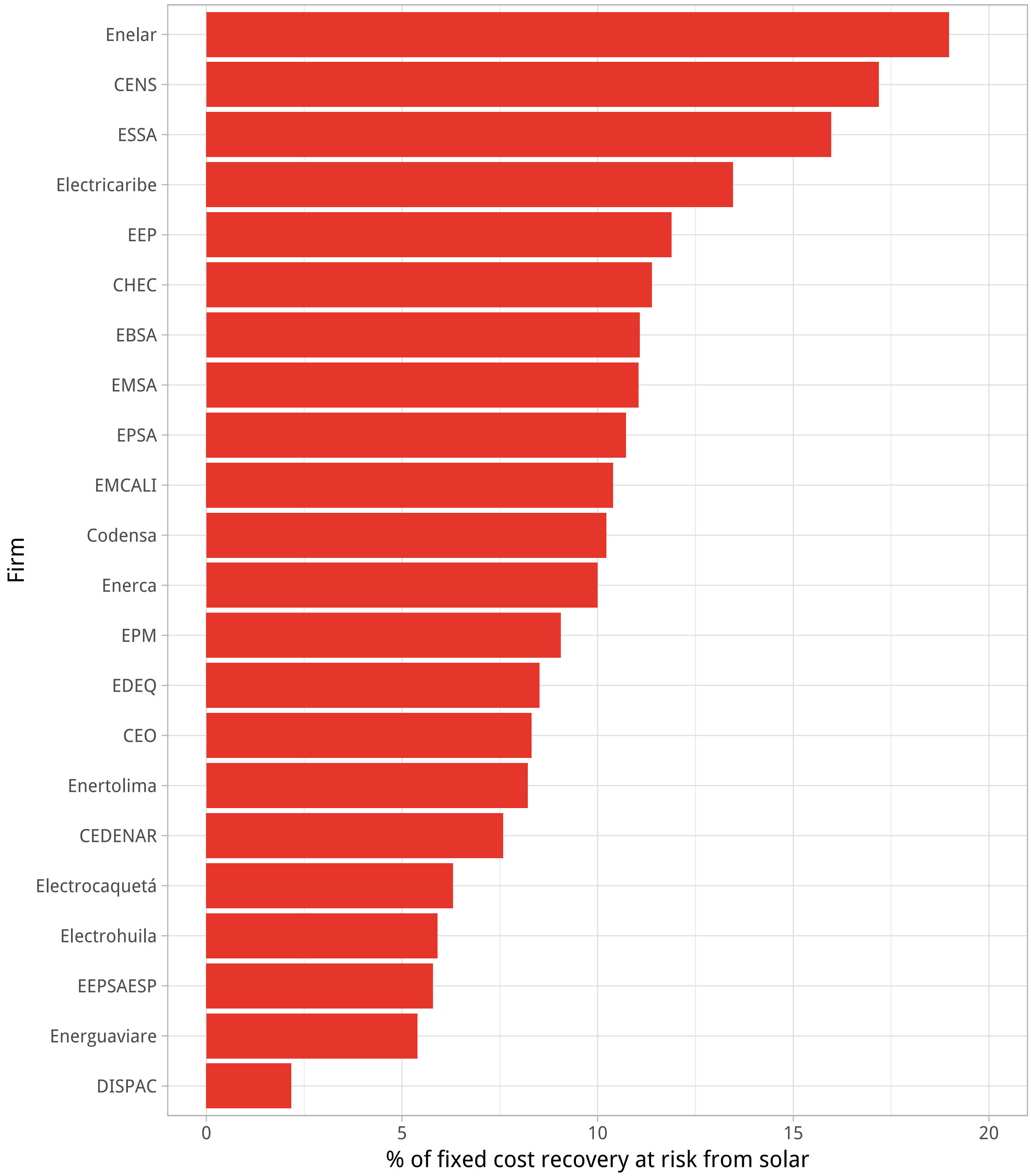
Notes: See notes to Figure 20. The adoption calculation assumes the efficient tariff that sets the marginal price equal to social marginal cost, plus net metering at the efficient price for solar generation.

Figure 22: Percentage of utility fixed cost recovery at risk from adoption of rooftop solar, for existing tariffs and different discount rates and installation prices



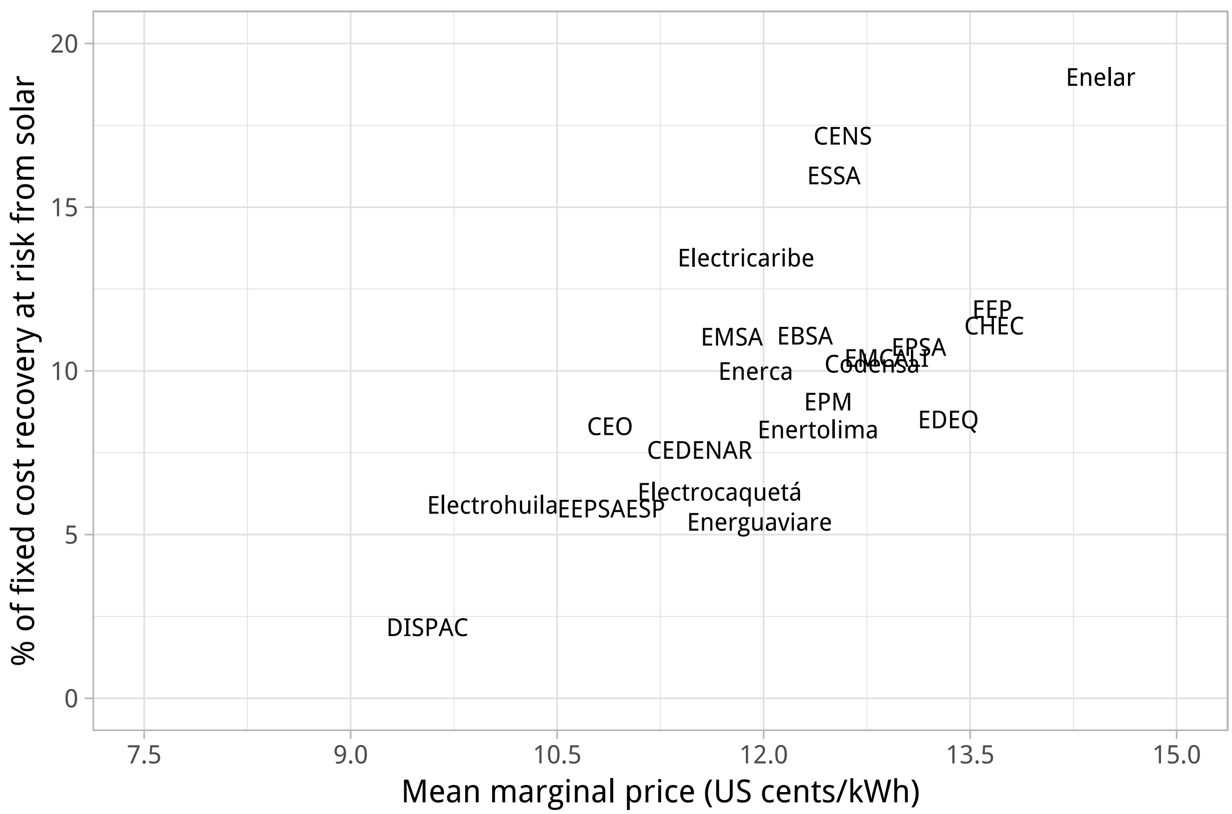
Notes: The graph shows the mean national reduction in the fixed costs recovered by electricity suppliers through their tariffs, assuming optimal adoption of solar by households. The horizontal axis shows different assumptions for the installed price of solar. Each line shows the result for different assumptions on discount rate. The calculation assumes a 2 kW solar installation. See also notes to Figure 20.

Figure 23: Percentage of utility fixed cost recovery at risk from adoption of rooftop solar, for existing tariffs, by supplier



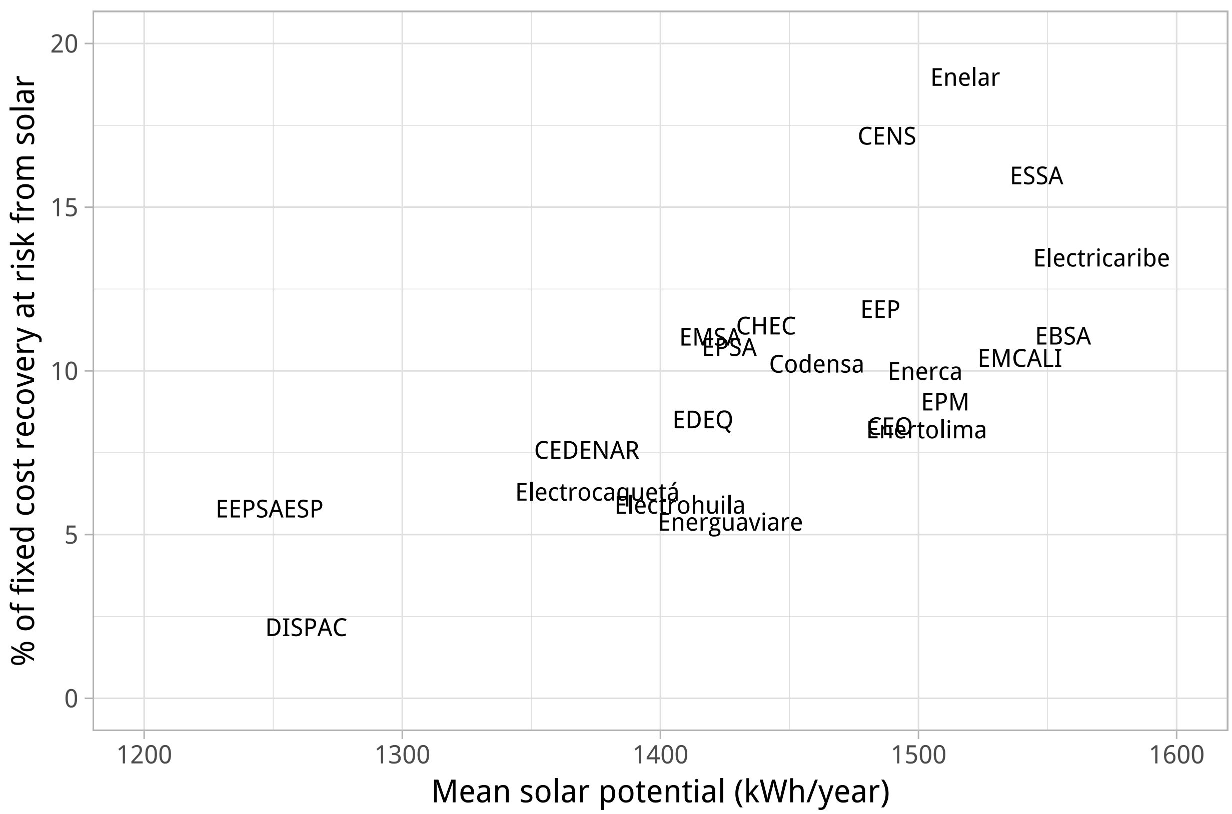
Notes: The graph shows the reduction in fixed cost recovery by electricity supplier, assuming optimal adoption of solar by households. The calculation assumes a 2 kW solar installation, a real discount rate of 5%, and an installation cost of US$2000 per kW. See also notes to Figure 20.

Figure 24: Relationship between fixed cost recovery at risk and mean marginal prices, by supplier



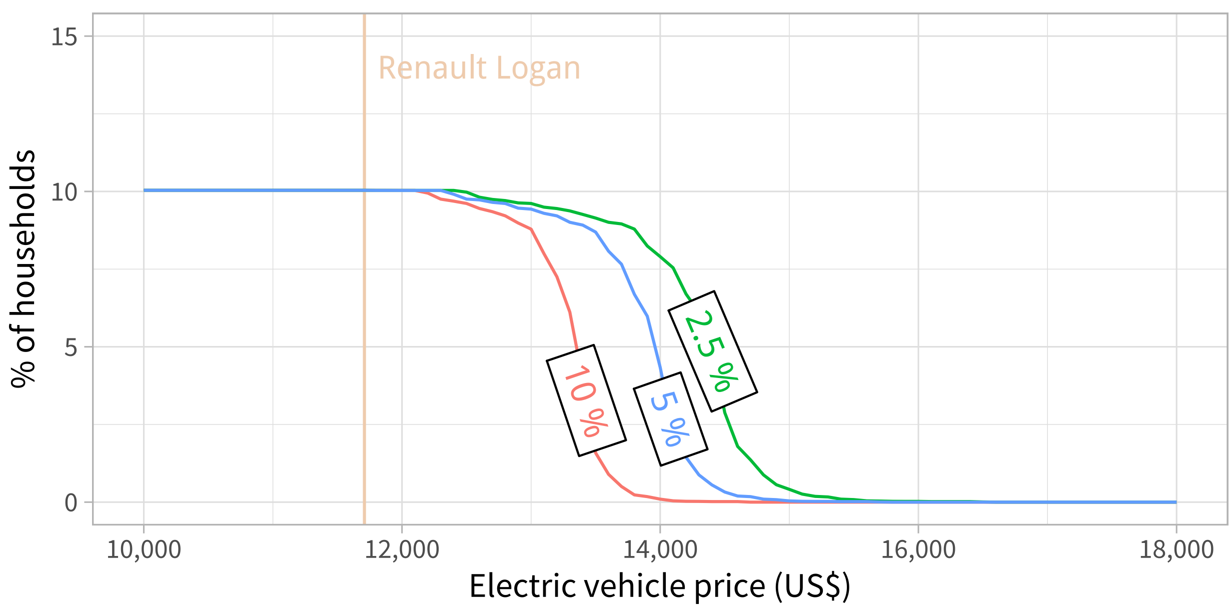
Notes: The graph shows the relationship between the reduction in fixed cost recovery by electricity supplier, assuming optimal adoption of solar by households, and the mean marginal price faced by households served by that utility. The calculation assumes a 2 kW solar installation, a real discount rate of 5%, and an installation cost of US$2000 per kW. See also notes to Figure 20.

Figure 25: Relationship between fixed cost recovery at risk and mean solar potential, by supplier



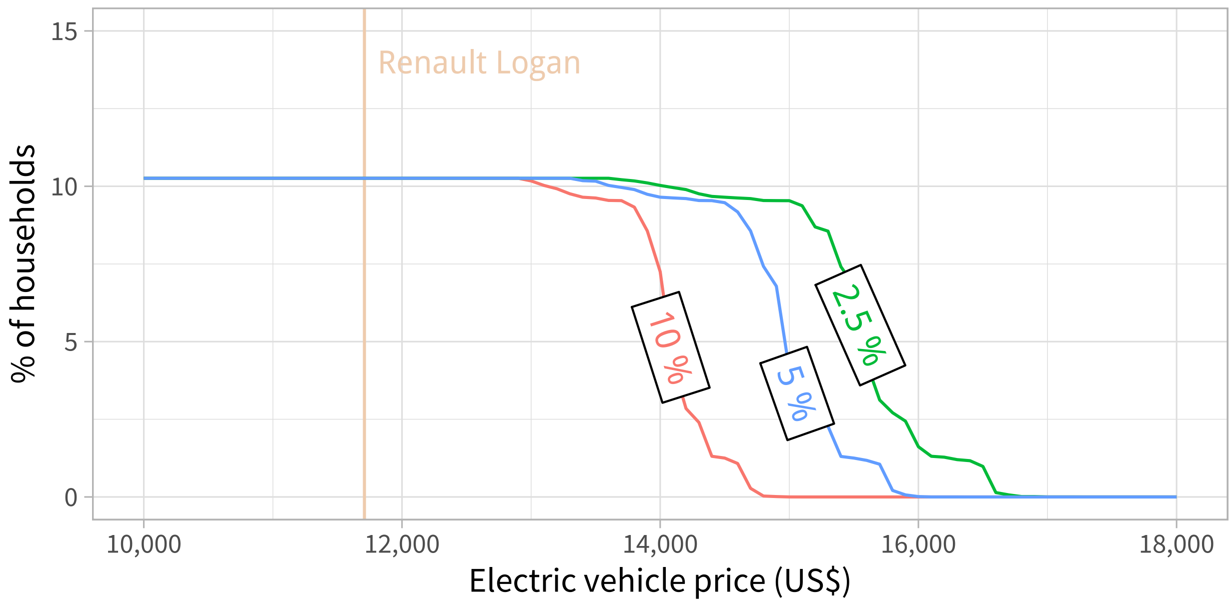
Notes: The graph shows the relationship between the reduction in fixed cost recovery by electricity supplier, assuming optimal adoption of solar by households, and the mean solar potential for households served by that utility. The calculation assumes a 2 kW solar installation, a real discount rate of 5%, and an installation cost of US$2000 per kW. See also notes to Figure 20.

Figure 26: Optimal adoption of electric vehicles in Colombia under existing tariffs, for different discount rates and vehicle prices



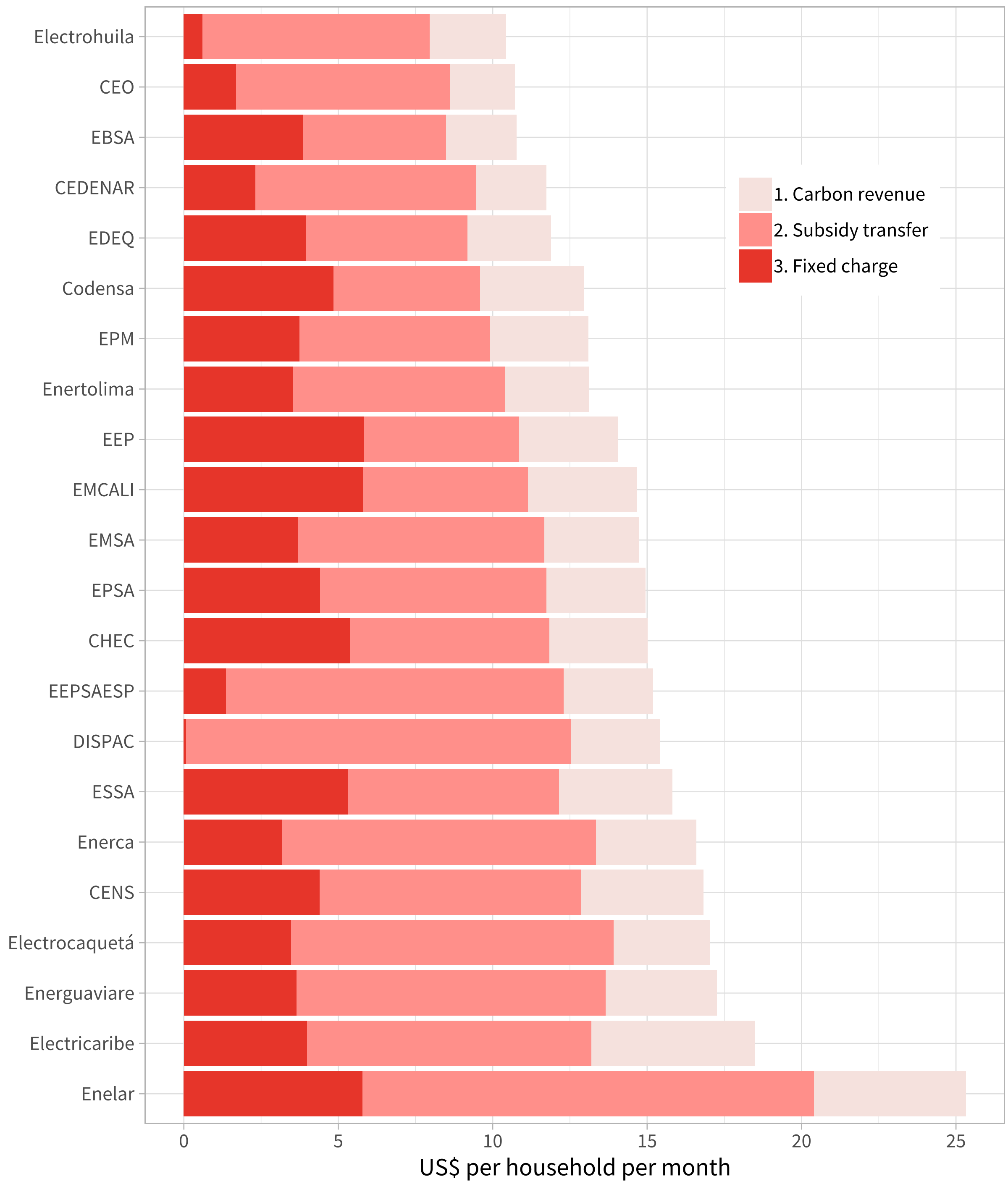
Notes: Each line shows the percentage of all households for which adopting an electric vehicle instead of a gasoline vehicle (Renault Zoe instead of a Renault Logan) would be privately optimal, as a function of the assumed electric vehicle price, for a different discount rate assumption. Only home owners who currently own a vehicle are assumed to be candidates for an electric vehicle. The adoption calculation assumes the existing retail tariff structure.

Figure 27: Optimal adoption of electric vehicles in Colombia for counterfactual efficient tariffs



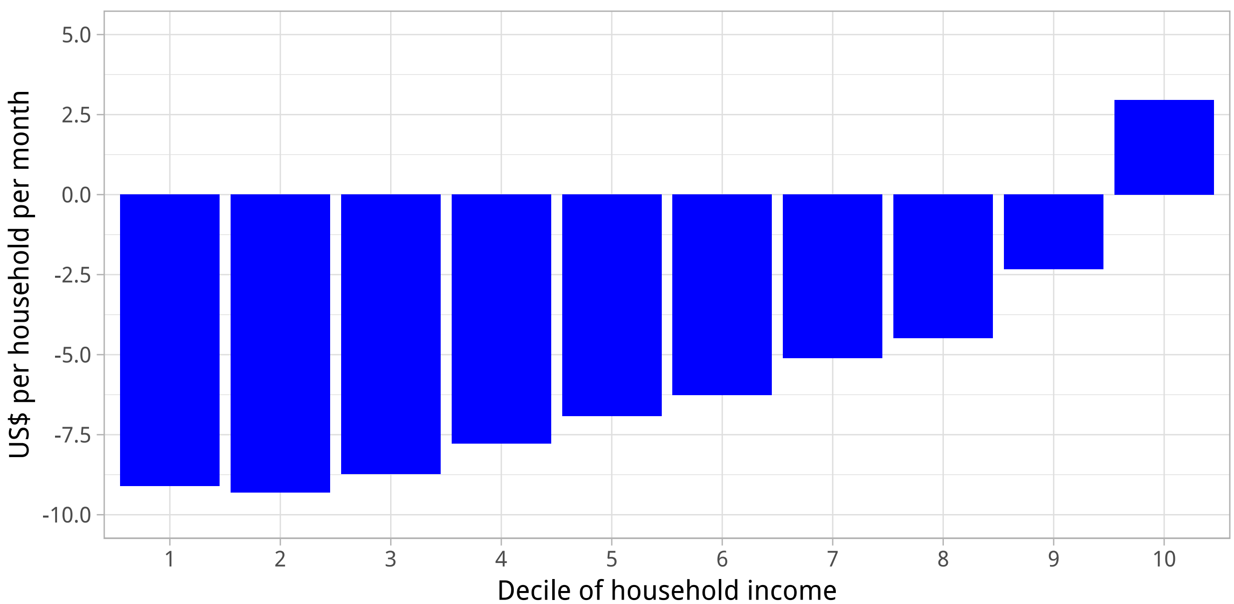
Notes: See notes to Figure 26. The adoption calculation assumes the efficient tariff that sets the marginal price equal to the social marginal cost.

Figure 28: Contributions to fixed cost recovery under counterfactual tariffs, by electricity distributor



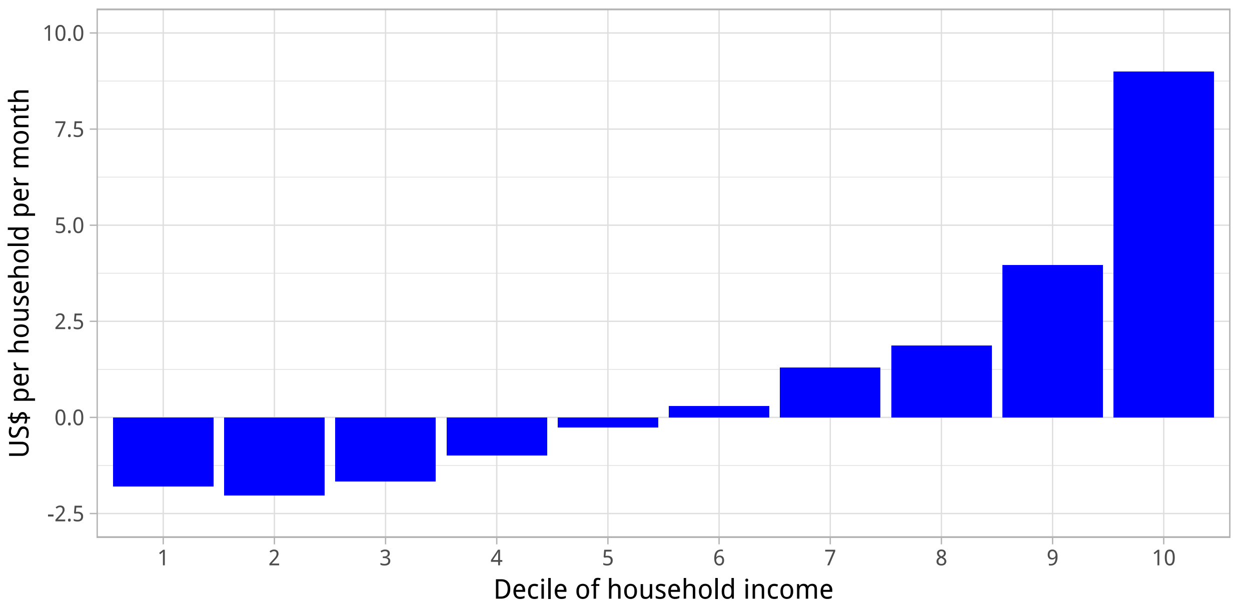
Notes: Each bar corresponds to one electricity distributor. The total length of the bar is the fixed costs per household that need to be recovered. The three components of fixed cost recovery are (i) revenue from the carbon tax embedded in the optimal price per kWh, (ii) existing subsidy transfers from non-residential users of the government, and (iii) fixed charges paid by households.

Figure 29: Distributional effect of eliminating subsidy transfers and setting fixed charges equal across households



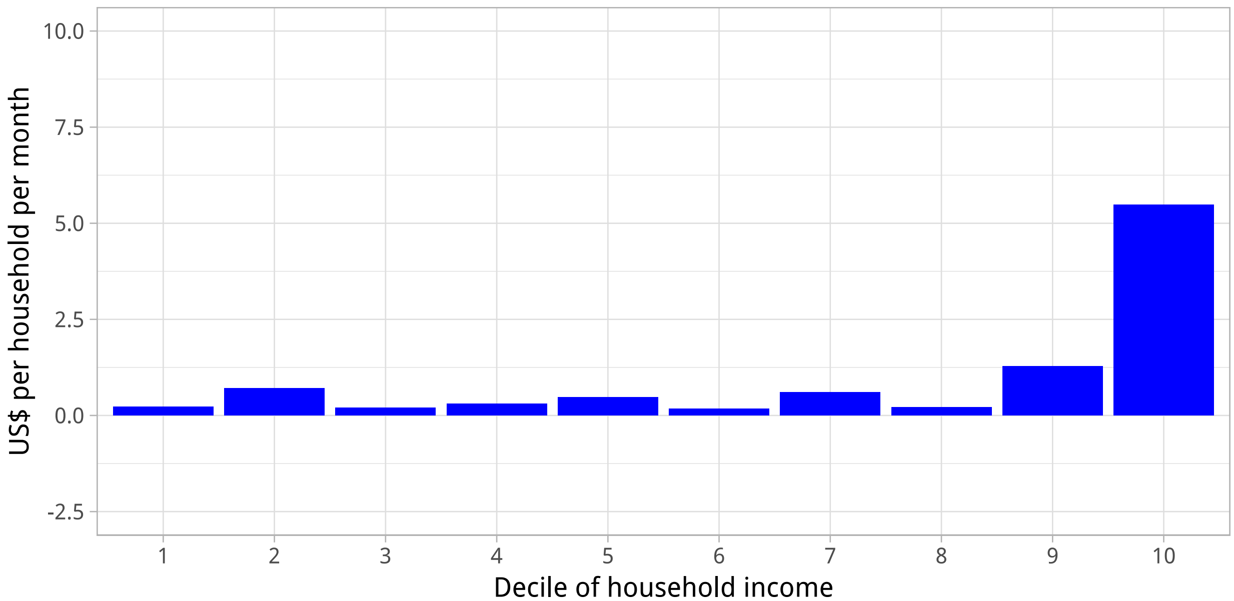
Notes: Each bar corresponds to an income decile in the Colombian population (1 = lowest, 10 = highest). The height of the bar is the mean change in consumer surplus for a counterfactual tariff with the variable charge equal to social marginal cost and the remaining fixed costs divided equally across households in each distribution territory. Consumer surplus and the change in consumption under the new tariff are calculated under the assumption of linear demand and an price elasticity of -0.30.

Figure 30: Distributional effect of keeping subsidy transfers and setting fixed charges equal across households



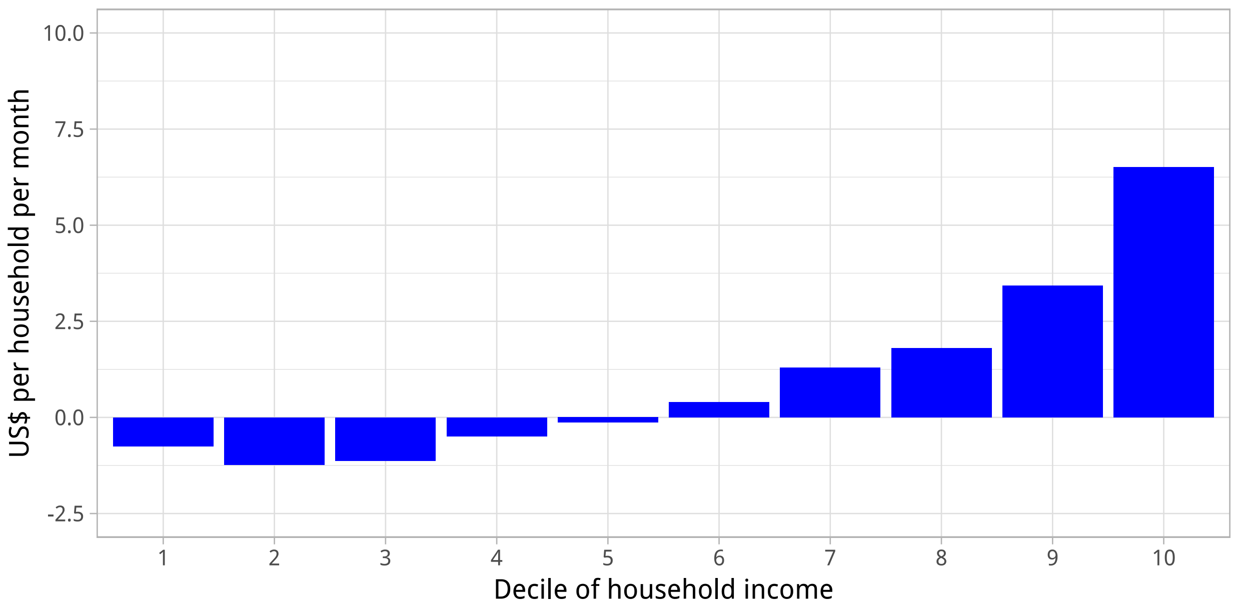
Notes: See notes to Figure 29. The fixed costs required to be recovered are reduced by the amount of the current subsidy transfer to the electricity distributor. The remaining costs are divided equally across the households in each distribution territory.

Figure 31: Distributional effect of eliminating fixed charges for households receiving subsidized health insurance



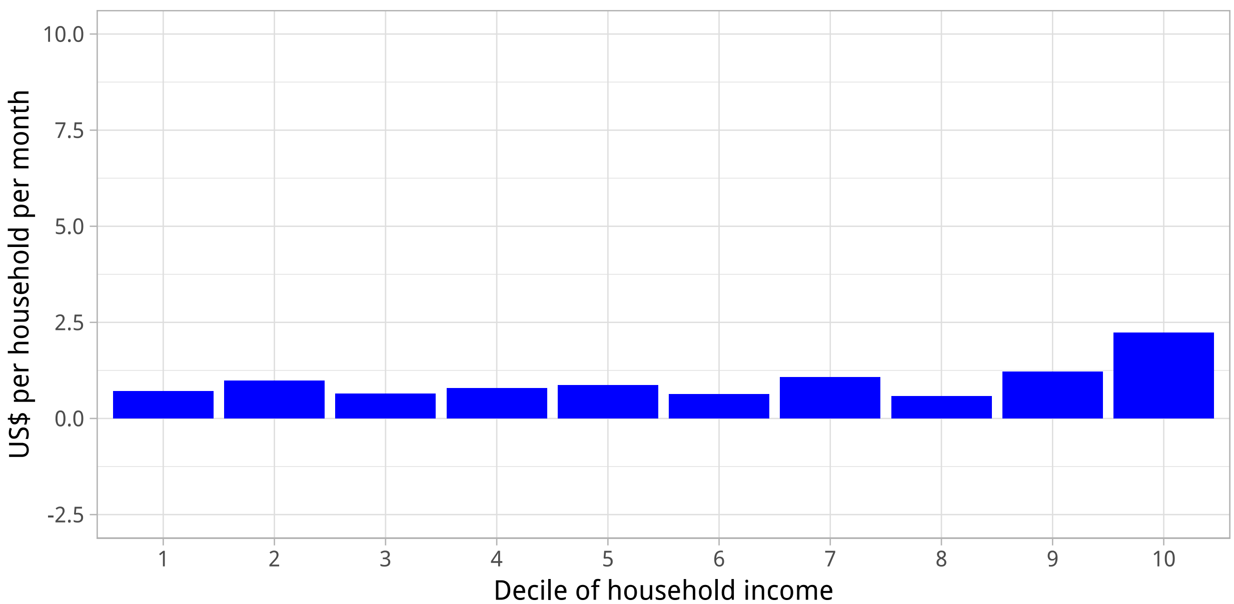
Notes: See notes to Figure 29. After deducting the current subsidy transfer, the fixed costs required to be recovered are divided equally across the households in each distribution territory who do not have any members receiving the government-subsidized health insurance. Fixed charges are zero for households with at least one member receiving subsidized health insurance.

Figure 32: Distributional effect of setting fixed charges based on share of predicted squared consumption



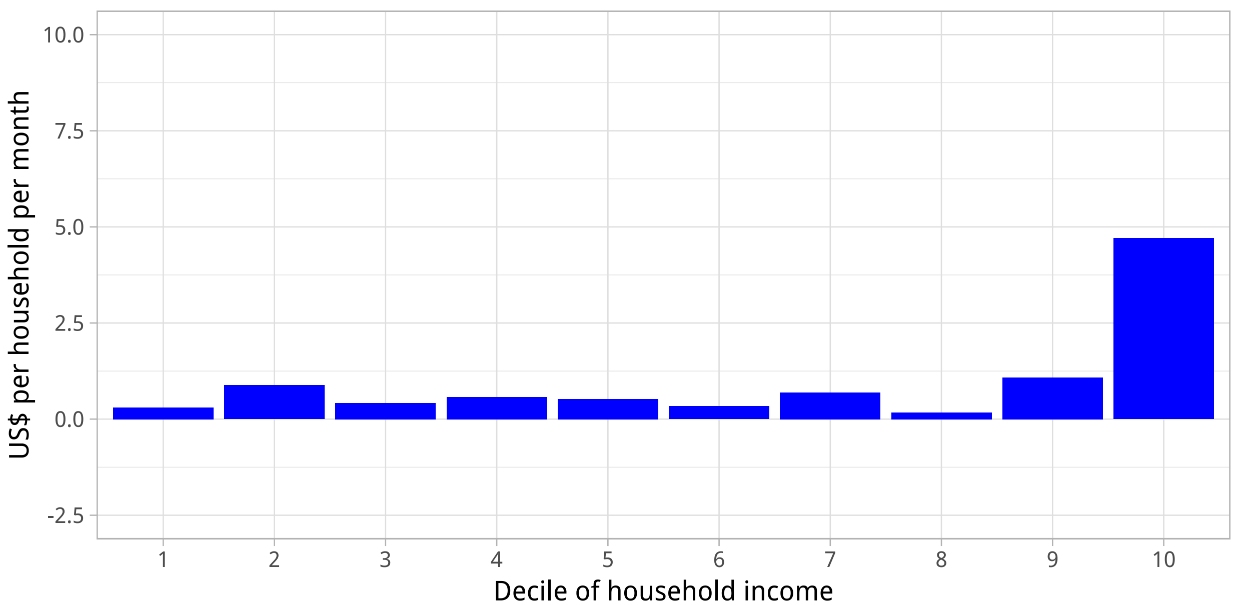
Notes: See notes to Figure 29. Fixed charges are set based the predicted value of the household's squared consumption, from a household-level regression of squared consumption on household characteristics, as a share of the total for all households in the distribution territory.

Figure 33: Distributional effect of allocating subsidies based on predicted squared consumption and access to subsidized health insurance



Notes: See notes to Figure 29. This allocation mechanism for fixed charges combines the approaches in Tables 31 and 32. Fixed charges are zero for households receiving the government-subsidized health insurance. The remaining households receive an allocation of fixed charges based on the predicted value of the household's square consumption, as a share of the total for the distribution territory.

Figure 34: Distributional effect of allocating subsidies based on predicted squared consumption and access to subsidized health insurance, using dwelling characteristics only



Notes: See notes to Figure 33. The prediction of squared consumption is restricted to observable characteristics of the dwelling: size, materials, tenure, access to public utiliites, and location.