

Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency[†]

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Economists favor pricing pollution in part so that consumers face the full social marginal cost (SMC) of goods and services. But even absent externalities, retail electricity prices typically exceed private marginal cost, due to a utility's need to cover average costs. Furthermore, the SMC of electricity can fluctuate widely hour-to-hour, while retail prices do not. We show that residential electricity rates exceed average SMC in most of the US, but there is large geographic and temporal variation. This finding has important implications for pass-through of pollution costs, as well as for policies promoting dynamic pricing, alternative energy, and reduced electricity consumption. (JEL D62, L94, L98, Q42, Q53)

Economically efficient decision-making by producers and consumers relies on prices accurately reflecting the short-run social marginal cost of supply. However, in utility industries that have traditionally been viewed as natural monopolies, the theoretical ideal of marginal cost pricing has been elusive in practice. One stream of research dating back to Ramsey (1927) has examined how price discrimination and nonlinear tariffs can be used to mitigate deadweight loss while still allowing a utility with declining average cost to recover its total costs. Another research literature, growing out of Pigou's (1920) seminal work, has shown that environmental externalities lead firms to charge prices below social marginal cost. A third literature—starting with Boiteux (1960) and Steiner (1957)—has emphasized that the highly time-varying cost of delivering electricity, due to its high cost of storage, suggests the need for dynamic pricing in order to reflect the constantly changing cost.

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In this paper, we examine the relationship between marginal retail prices and the social marginal cost of supply in the electricity industry from 2014 to 2016. We focus on the most common residential electricity tariffs. In the \$174 billion per year residential market, the efficiency implications of a gap between the marginal cost of service and the marginal price paid by consumers are growing more serious with the increasing availability of substitute technologies, such as rooftop solar photovoltaics and small-scale battery storage. These technologies make the demand of end-use consumers more price-elastic, and therefore can magnify the deadweight loss from mispricing. Utilities around the world have expressed concern about the prospect of a “death spiral,” in which reduced consumption leads to higher regulated prices, which in turn leads to more consumption decline (Costello and Hemphill 2014).

Retail pricing in electricity markets suffers from at least three distortions: (i) because neither buyers nor sellers bear the pollution costs of electricity generation, prices will tend to be below their optimal level, (ii) because there are significant economies of scale in electricity distribution, and possibly other parts of the value chain, a linear price likely will need to exceed private marginal cost of the utility in order to recover its total costs, and (iii) because electricity is not economically storable and demand fluctuates continuously, the private marginal cost changes constantly within a day, yet retail prices do not reflect those fluctuations. Importantly, these distortions do not all work in the same direction and can at times potentially offset one another. Research on the electricity industry and the policies that impact it, however, has tended to focus on each of these distortions in isolation. Since at least Lipsey and Lancaster (1956) and Buchanan (1969), it has been well understood in economics that markets with multiple distortions may not be improved by addressing one of the distortions in isolation.

In this paper, we take a step toward a holistic view by attempting to measure, at high frequency, the departure of residential electricity prices from the economic ideal of short-run social marginal cost (SRS MC). We then decompose the departure from SRS MC into the component caused by charging a price that differs from the average SRS MC and the component caused by charging a constant price that does not vary over short time periods, as SRS MC does. The analysis is primarily an exercise in measurement of various aspects of SRS MC and the marginal prices faced by customers. Some of these measures are available in public data, while some we estimate, because direct measures are not available.

We break the construction of price versus social marginal cost into three components: retail price, private marginal cost, and external marginal cost. Section II presents the residential electricity price data and our calculation of marginal electricity price. Section III discusses private marginal cost, for which we begin with hourly wholesale electricity price data, but then make adjustments to incorporate time-varying costs associated with local distribution. Section IV brings in externalities, estimating marginal externality costs for the marginal consumption of electricity by region. In Section V, we bring the three measures together to analyze the deviation of price from SRS MC, then calculate and decompose the implied deadweight loss. In Section VI we discuss several potential policy implications of our calculation. We conclude in Section VII with a discussion of the broader relevance of our findings.

I. Related Literature

This paper relates to three strands of literature that have examined electricity pricing from different perspectives. The first concerns itself with the central challenge of natural monopoly pricing: minimizing deadweight loss while ensuring the recovery of average costs (Brown and Sibley 1986; Kahn 1988; Braeutigam 1989; Borenstein 2016). Here the main concern has been the inclusion of fixed and sunk costs in volumetric prices, potentially driving prices above marginal cost.¹ Various solutions have been proposed and at least partially implemented, including price discrimination with linear tariffs (Ramsey 1927; Boiteux 1960, 1971), two-part pricing (Feldstein 1972; Littlechild 1975), and more sophisticated nonlinear pricing (Wilson 1997; Laffont, Rey, and Tirole 1998). Yet, despite a plethora of complex rate structures in use, there is a general perception that utility rates do not closely approximate (private) marginal costs (Friedman 1991; Puller and West 2013). Davis and Muehlegger (2010) estimate marginal tariff rates for natural gas utilities and find that they do not adjust fully to fluctuations in wholesale gas supply costs, while Borenstein and Davis (2012) examine the equity effects of these departures from marginal cost pricing of natural gas and discuss the potential equity and efficiency effects of changing fixed charges. We are not aware of any comprehensive effort to measure the departure from marginal cost of retail electricity prices.

A second literature on electricity pricing is concerned with the variation of costs over time, particularly those driven by scarcity or capacity constraints. Early theory focused on forms of peak-load, or capacity, pricing that could at least partially capture scarcity effects in otherwise static tariff structures (Boiteux 1960; Steiner 1957; Joskow 1976; Oren, Smith, and Wilson 1985; Crew and Kleindorfer 1976). The advent of advanced metering technology made feasible the prospect of dynamic electricity pricing (Borenstein 2005; Joskow and Wolfram 2012) that could capture scarcity costs through frequently varying linear prices. However, despite a growing literature on its practical effectiveness (Jessoe and Rapson 2014), dynamic pricing is still quite rare. As we describe below, only 4 percent of residential US customers are on a time-varying price, and the bulk of those customers are on static time-of-use prices. The lack of dynamic retail pricing has been widely cited as a source of inefficiency in the electricity industry (Borenstein and Holland 2005; Borenstein 2005; Joskow and Wolfram 2012; Puller and West 2013).

The most recently active strand of literature on the efficiency of electricity prices concerns their relationship with the external costs of electricity production and consumption (Cullen 2013; Graff Zivin, Kotchen, and Mansur 2014; Novan 2015; Holland et al. 2016; Callaway, Fowlie, and McCormick 2018). The environmental impacts of electricity supply, particularly with respect to climate change, are significant and have been the focus of policy activity for at least two decades. Environmental economists have generally advocated for the pricing of external costs, through either Pigouvian taxation or cap-and-trade systems, in this and other industries. However, alternative approaches, such as subsidies for clean energy through

¹Low inframarginal costs can drive average cost below marginal cost in some circumstances, most notably utilities that have access to limited quantities of cheap power, such as from federal hydroelectric generation.

either tax credits or performance standards and non-market interventions relating to energy efficiency, have been more common in practice than the pricing of externalities.² These latter programs have been criticized by economists on several grounds.

Several papers have addressed the optimality of environmental policies with respect to consumer incentives. These studies have raised concerns about policies that limit the pass-through of externality costs. For example, the impact of intensity standards for limiting carbon emissions (Bushnell et al. 2017), the use of output-based allocation of allowances in cap-and-trade systems (Fowlie 2012; Fischer and Fox 2012), and energy efficiency interventions (Allcott and Greenstone 2017). A common theme is that many “green” policies tend to promote overconsumption as they fail to properly reflect marginal environmental damages in electricity costs (Borenstein 2012). However, with the exception of Allcott and Greenstone (2017), these papers address the design of optimal externality policies from an underlying assumption that retail prices accurately reflect private (but not social) marginal cost. To the extent that preexisting distortions to retail prices, due to natural monopoly pricing for example, have already distorted retail prices, the optimal environmental policy can look very different from the one applied in a system with prices reflecting private marginal costs.

II. Residential Electricity Pricing

The challenge in constructing data on residential electricity pricing is to accurately characterize the marginal price that a customer faces. While data on aggregate revenues and quantity sales to residential customers by utility are available, those data alone only allow inference about the average price paid by residential customers. Optimizing consumers, however, would respond to the marginal price of electricity, not the average price. Thus, we must adjust the analysis in order to get a more accurate measure of marginal price.

Our primary source of utility sales data is the Energy Information Administration’s Form EIA-861 survey (Energy Information Administration 2017a). The EIA-861 is an annual survey of electric utilities that covers many aspects of their commercial activities.³ The EIA-861 data include for every utility-state annual total revenues from residential customers, total number of customers, and total kilowatt-hours (kWh) sold. Dividing total revenues by total kWh yields an average price.⁴

²For example, the Obama-era EPA regulatory initiative known as the Clean Power Plan offered to states several options for compliance, including an intensity standard or direct subsidies of zero-carbon generation sources, as alternatives to carbon pricing (Fowlie et al. 2014).

³To be precise, our sample contains 2,104 utility-state combinations. Utilities report their operations separately by state to the EIA. For each utility-state combination, we calculate each measure separately for each year and then for the maps we take the average across the years for which the utility-state is in the dataset (which is 2014, 2015, and 2016 for almost all utility-states). See the online Appendix for further details. For simplicity, we refer to the unit of observation as a utility-state. A smaller number of major utilities are surveyed monthly, covering about two-thirds of the household customers in the annual survey Energy Information Administration (2017b). In the online Appendix, we discuss a robustness check that we carry out using the monthly survey. We find very small seasonal changes in retail rates.

⁴Throughout this paper, we use the standard measurement of electricity quantity, kilowatt-hours. The average US household uses about 900 kWh per month.

However, many utilities have monthly fixed charges. In order to calculate the marginal price, we remove the fixed charges. The utility fixed charges for residential customers come from the National Renewable Energy Laboratory's Utility Rate Database (URDB) (National Renewable Energy Laboratory 2017). The URDB is described in more detail in the online Appendix. It includes many residential rates for each utility. For each utility we chose what appeared to be the primary or basic rate (the process of determining this rate is described in the online Appendix) and took the fixed charge from that rate. We used this fixed charge to approximate fixed revenues—total customers multiplied by fixed charge—and subtracted that amount from the total residential revenues. We divided the remainder by kWh sold to get the average variable rate, which we take as our measure of marginal price.

In most of the country, the same company is responsible for procuring or producing electricity on behalf of residential customers and physically delivering it through local distribution lines. In some parts of the country, however, the electricity sector has been restructured such that customers can choose their “retail provider” from among many companies that buy power wholesale and sell to the customer at retail. About 32 percent of residential customers in the United States are eligible to choose their retail provider, and just under half of those customers choose a retailer that is different from their local distribution company. Full details of how we handle these cases can be found in the online Appendix.

Removing the fixed component of customers' bills still does not fully capture marginal rates if those rates vary with the level of consumption, such as from increasing-block or decreasing-block pricing—under which marginal price rises or falls in steps as a household's consumption increases. Thus, some customers of a given utility are likely to have a higher marginal rate, and others a lower marginal rate, than the one we use. Based on the 1,743 utilities with rates in the URDB, about 58 percent of residential customers are served by a utility for which it appears that the marginal price in the primary residential tariff varies with consumption, of which about 37 percent face increasing-block pricing and about 21 percent face decreasing block pricing.⁵

Similarly, we do not capture differences in static rates across customers of a utility. Many utilities, for instance, have lower rates for low-income households. But it could also occur if a utility charges rates that vary by geographic region. It is worth noting, however, that the failure to reflect variations in marginal rates across customers that are not based on marginal cost is very likely to lead to understated estimates of the deadweight loss associated with residential rates. This is because deadweight loss increases more than proportionally with the difference between price and marginal cost. Thus, for linear pricing, if all customers have the same demand elasticity, deadweight loss is minimized by charging all customers the same linear price.

In all cases, we also have assumed that the primary residential rate had no time-varying component, including no time-of-use variation, no critical peak

⁵The share of *quantity* sold on nonlinear pricing is somewhat smaller, as the retail providers utilizing increasing-block pricing serve smaller average residential demand per customer. Overall, providers serving larger numbers of customers are more likely to use increasing-block pricing. Of the 1,743 retail electricity providers in our URDB sample, about 39 percent utilize nonlinear marginal pricing, with about 15 percent using increasing-block pricing and about 24 percent using decreasing block pricing in their primary residential rates.

pricing, no demand charges, and no real-time pricing. The prevalence of these kinds of tariffs is very low among residential customers. During the period 2014–2016, about 4 percent of customers were on some form of time-varying pricing, and just under 6 percent of customers were part of some form of demand response rebate program.⁶

Our final dataset on residential electricity pricing covers an average of 128.2 million residential customers during the period 2014–2016, with average annual total sales of 1.384 trillion kWhs and revenues of \$174 billion. After incorporating our estimates of fixed charges we were able to calculate the average variable per-kWh price faced by just over 93 percent of residential customers and kWh sales.

A. Is Marginal Price the Correct Measure?

A number of papers, most prominently Ito (2014), have challenged the belief that electricity consumers respond strictly to marginal price.⁷ Ito finds that in the context of steeply increasing-block electricity pricing at two large utilities in California, consumers are more accurately characterized as responding to the average price they face, rather than the marginal price.

These analyses, however, do not address the extent to which consumers are able to separate recurring fixed charges from volume-based charges.⁸ Understanding and distinguishing a monthly fixed charge from volumetric pricing seems likely to be much less difficult than diagnosing which step of an increasing-block marginal price schedule the household is likely to end up on at the end of the month. Ito and Zhang (2020) is the only work of which we are aware that addresses the former question. They find strong evidence that consumers respond to changes in marginal prices apart from changes in fixed charges.⁹

Luckily, for our analysis, the three large utilities in California that have steep increasing-block electricity price schedules, where the steps differ by more than \$0.04 per kWh, are outliers in the United States as a whole. Out of the 1,743 utilities we study that are in the URDB, there are 673 with nonconstant marginal price. Among those 673, the median absolute difference between the lowest and highest tier across all US utilities was \$0.019 per kWh, with 75 percent of the rates showing a difference of less than \$0.037 per kWh.¹⁰

⁶The EIA-861 data that are the source of these figures do not allow one to calculate the overlap between these two sets of customers, but it is probably significant. Furthermore, a very large share of the customers on time-varying pricing are on simple peak/off-peak rates with fixed time periods and fairly small differentials between peak and off-peak.

⁷See also Shin (1985) and Borenstein (2009).

⁸The customers in Ito's sample faced increasing-block pricing, but no fixed charge.

⁹If customers are not able to distinguish fixed from marginal prices and make their decisions based on average price, this would raise perceived prices most for customers in the middle of the country, as shown in Figure 2, where we find that price is below social marginal cost. However, it would also raise prices in the Northeast, where we generally find prices are already substantially above social marginal cost. Though fixed charges are common, they are not typically a large share of the total bill, averaging about 10 percent as suggested by the difference between average price and variable price in Table 1.

¹⁰Furthermore, even in California the variation in marginal price across the steps has shrunk significantly in the last decade for the vast majority of households, from a ratio of more than 3 to 1 in 2014, to a ratio of less than 1.4 to 1 in 2017. There remains a higher "superuser" rate that applies for usage over 400 percent of the baseline quantity, but that is relevant for just a few percent of households.

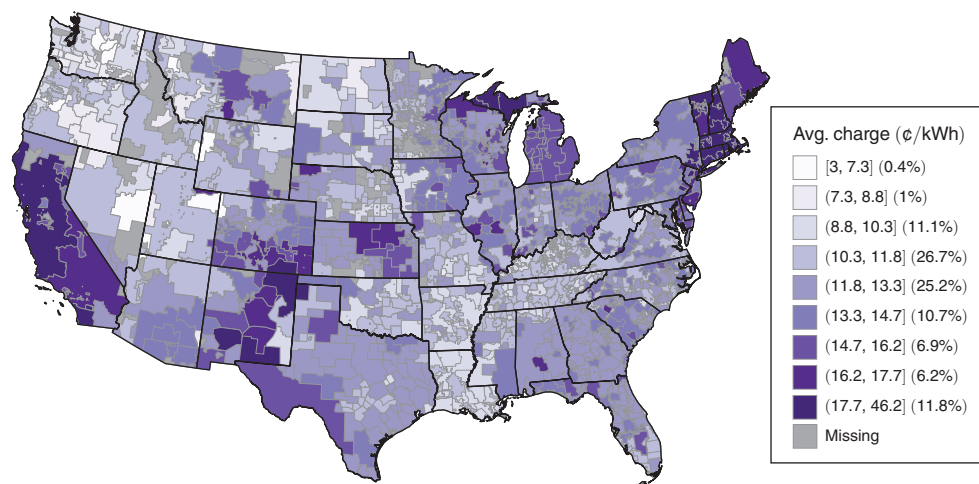


FIGURE 1. AVERAGE PRICE PER KILOWATT-HOUR

To the extent that customers respond to the average variable price they face in an increasing-block price schedule—a possible third “wrong”—they would perceive a lower incremental cost than the actual marginal price. This would somewhat reduce their response to the very high marginal prices in California and a few other areas, however perceived prices in most of those areas with significant increasing-block pricing would still substantially exceed social marginal cost. Decreasing-block price schedules would have the opposite effect, raising the perceived incremental cost of consumption above the true marginal price. Nonetheless, the existence of marginal pricing that changes with consumption quantity should be recognized in interpreting our results.

B. Residential Electricity Pricing Results

We present many results in this analysis graphically at the utility-state level for the 48 contiguous US states. To do this, we use utility service territory shape files from Homeland Infrastructure Foundation-Level Data (HIFLD).¹¹ In all of the maps, the percentages in parentheses in the legend are the percent of residential customers in each category, and areas of the map with no data are represented by a dark gray shade, such as in part of the Northern border area of Montana. Values represented for each utility-state are the sales-weighted average across the three years of data.

Figure 1 presents the average price per kilowatt-hour (kWh), over 2014–2016, by utility-state. It shows, for instance, that California has among the highest average prices per kilowatt-hour for residential customers, but that the very highest prices are in the Northeast. The lowest prices can be found in much of the Northwest and

¹¹ <https://hifld-geoplatom.opendata.arcgis.com/datasets/geoplatom::electric-retail-service-territories-1/about> (accessed July 28, 2022). The map captures more than 99 percent of all residential customers but omits a few small municipal and coop utilities.

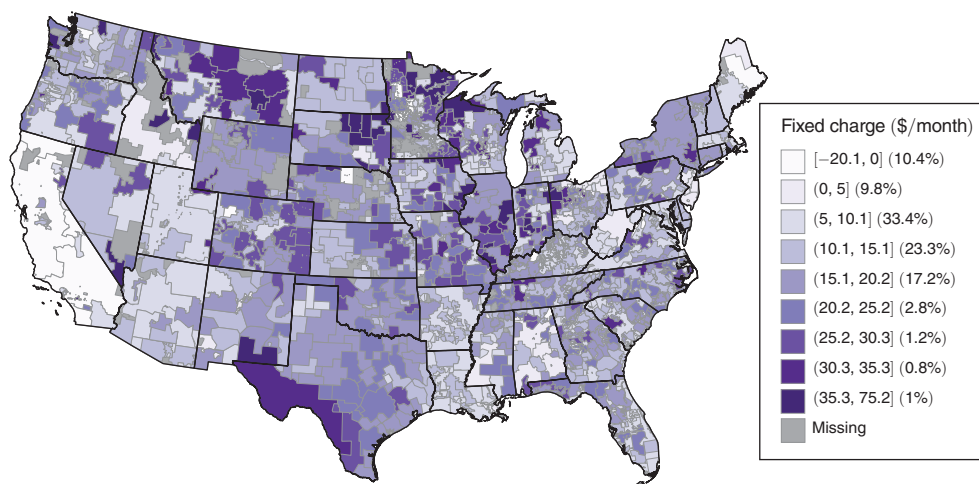


FIGURE 2. FIXED MONTHLY CHARGE

the South. It also shows that even in fairly high-priced states like California and New York, there are some areas with substantially lower prices.

Figure 2 presents monthly fixed charges as discussed above. Much of California has zero or slightly negative fixed charges—which occurs because of a semi-annual “climate rebate” that each residential customer gets as part of the state’s cap-and-trade program—while some utilities in the center of the country have fixed charges of \$30 per month or higher.

Figure 3 shows the results from adjusting the average price for the monthly fixed charges to get an average variable price. Nationally, the adjustment for monthly fixed charges lowers the marginal price by about \$0.01 per kWh. We would expect this to be an accurate indicator of the marginal price that consumers face if the utility uses a simple two-part tariff. For those utilities that utilize increasing-block or decreasing-block pricing, as discussed earlier, this captures the average variable price across customers.¹² The average variable prices illustrated in this figure are used in our calculation of the gap between marginal price and social marginal cost.

Table 1 presents the quantity-weighted summary statistics on average price, fixed charge and average variable charge across the 6,215 utility-state-years in the entire sample. For the maps, we calculate the statistics separately for each utility-state-year it is in the dataset, and then take the quantity-weighted average of those years.

¹²How closely this reflects the average of the marginal prices faced by customers depends on the distribution of customers across the tiers of the block pricing. See Borenstein (2009) and Ito (2014) for further discussion.

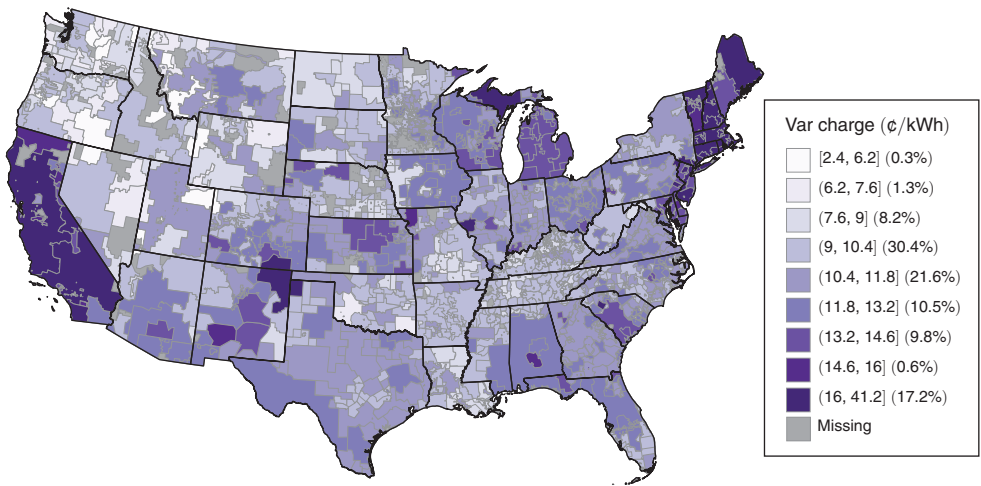


FIGURE 3. MARGINAL PRICE PER KILOWATT-HOUR

TABLE 1—SUMMARY STATISTICS OF RESIDENTIAL RATES

	Mean	SD	Min	P10	P90	Max
Retail fixed charge (\$/month)	10.78	7.65	−26.11	2.53	20.00	75.53
Retail variable price (¢/kWh)	11.49	3.07	2.36	8.79	16.29	48.22
Retail average price (¢/kWh)	12.61	3.01	2.96	9.83	16.65	53.31

Notes: $N = 6,215$ (utility-state-years). Statistics are sales-weighted.

III. Private Marginal Costs

Provided that wholesale electricity markets are competitive,¹³ the primary component of the private marginal cost of supplying electricity is captured in the wholesale price. We collected wholesale prices from regions that are part of Independent System Operator (ISO) control areas. ISOs calculate and report locational marginal prices (LMPs), which reflect the marginal cost of electricity generation plus high-voltage transmission congestion and line losses (due to heat dissipation of energy during transport). These prices literally represent the derivative of total system production cost with respect to a change in consumption at a given location (node), accounting for all relevant transmission, operating reserve, and unit-level operating constraints considered by the system operators. Electricity prices are extremely volatile over time and geography due to a combination of volatile demand, a lack of economic storage, and frequently binding limits on low-cost production and/or transmission capacity. Technical constraints also limit the flexibility of some production resources and the ability to freely dispose of power. In addition, wind generation receives tax

¹³ Each organized electricity market operator estimates and reports a price-cost margin based upon its estimate of the marginal cost of supply. In the last decade these reports indicate very low to negative margins in most electricity markets (Federal Energy Regulatory Commission 2016).

subsidies that are based on quantity produced, effectively lowering their short-run private marginal cost to below zero. These factors combined to occasionally result in negative prices in regions with inflexible supply that is unable to export its surplus.

Some parts of the country, particularly the Southeast, have large areas that are not covered by ISOs. In those areas, we collected data that grid operators are required to file to the Federal Energy Regulatory Commission as part of the FERC Form-714 survey (Federal Energy Regulatory Commission 2017). This survey includes a requirement to report the “system lambda,” which is the engineering calculation of the shadow cost of changing production by one unit. Thus, ideally, it would correspond with the marginal cost, as reflected by a competitive market price, in the ISOs. In practice, however, much of the Form-714 data are obviously unreliable, exhibiting many consecutive hours of identical values and zero values where they are not plausible. As described in the online Appendix, we incorporate data for those areas where the Form-714 data seem to be most reliable. Nonetheless, the Form-714 data may understate the true private marginal cost, both because system lambda likely does not fully incorporate marginal transmission losses and congestion costs and because system lambdas may not fully incorporate scarcity rents in constrained hours.¹⁴

We calculate private marginal cost for each zip code based on LMP prices and/or system lambda values that are closest to the zip code, which allows those costs to include transmission losses and transmission congestion costs, and then aggregate up to utility levels. Full details of this calculation can be found in the online Appendix. Table 2 summarizes the wholesale power cost, weighted by hourly consumption, by regions designated by the North American Electricity Reliability Corporation (NERC), which correspond to fairly integrated grids. The one exception is that California is part of the Western Electricity Coordinating Council (WECC), but operates a wholesale electricity market that was not well integrated with the rest of the WECC during these years. The data allow us to break out California, so we do.¹⁵ As we discuss later, average prices are below levels generally considered sufficient to cover long-run average cost of a modern combined-cycle natural gas power plant, even at the very low gas prices that existed at this time. These averages, however, mask significant heterogeneity in prices both regionally and over time. When wholesale markets have experienced either scarcity conditions or high natural gas prices, wholesale prices have risen to extremely high levels. Each of our ISO-based markets experienced prices in individual hours well above \$1.00/kWh. This supports the viewpoint that market prices are capable of reflecting marginal costs that include

¹⁴ The wholesale prices in areas with ISOs are also imperfect measures because they likely incorporate some market power in some hours, although analysis by oversight divisions suggests very modest if any market power averaged over all periods (Bushnell et al. 2017). Unfortunately, comparing system lambdas to wholesale prices where they exist does not help to reveal the magnitude of these biases, because utilities in these areas typically report the market price as the system lambda for their region.

¹⁵ We Winsorize hourly prices at $-\$0.15/\text{kWh}$, because that is the minimum bid allowed in most ISO markets. A few observations of much lower prices appear in the data, but it is unclear whether they are data errors. Including all prices has a very small effect on average price calculations and the deadweight loss from price deviating from average SMC. But for a few utilities, extremely negative prices cause larger deadweight loss calculations from hourly SMC variation. We also did all calculations with hourly prices Winsorized at $\$0$, which has very little effect on any of the calculations compared to a $-\$0.15/\text{kWh}$ cutoff.

TABLE 2—WHOLESALE POWER PRICES BY NERC REGION (¢/kWh)

Region	Location	Mean	Min	P10	P90	Max
CA	California	3.39	−15.00	1.75	5.24	165.89
FRCC	Florida	2.59	−3.27	1.59	3.73	104.32
MRO	Upper Midwest	2.59	−15.00	1.34	3.89	185.82
NPCC	Northeast	4.10	−15.00	1.33	7.62	144.61
RFC	Great Lakes	3.49	−15.00	1.80	5.27	193.88
SERC	Southeast	3.06	−15.00	1.71	4.18	272.68
SPP	Oklahoma/TX	2.71	−15.00	1.50	3.84	465.59
TRE	Texas	2.82	−11.04	1.52	4.02	470.84
WECC	Non-CA West	3.09	−15.00	1.53	4.81	277.03

Note: Weighted by retail sales.

significant scarcity rents when applicable, and that the relatively low average prices are reflective of a lack of scarcity, rather than a systemic suppression of wholesale price below short-run marginal cost.

A. Distribution Losses

The private marginal costs calculated based on wholesale prices do not include the cost of local electricity distribution on low-voltage lines. The primary marginal cost of distribution is electricity losses. Losses from low-voltage distribution lines fall into two categories: a smaller share is attributed to “no-load” losses that occur in transformers, and a larger component is “resistive” losses that are a function of the flow on the line. No-load losses are fairly constant for a utility and vary across utilities as a function of the size of their systems. Resistive losses change constantly scaling with the square of the flow on a line.¹⁶ On average, around 25 percent of distribution losses are no-load with the remainder attributed to resistive losses.

A range of factors affect the magnitude of losses, including the distance electricity must be carried (approximately the inverse of geographic demand density), the density of load on circuits, the use of equipment to optimize voltage, and the volatility of demand. Demand volatility increases losses for a given average demand level due to the quadratic relationship between flow and resistive losses. Many of these factors are likely to differ between residential customers and commercial or industrial customers. Importantly, many industrial and some commercial customers take power from the distribution system at higher voltages than residential customers, which can substantially reduce the level of line losses.

Unfortunately, the only systematic data available on distribution line losses are reported on an annual basis by utility in the EIA-861, with no breakdown by class of customers, or by hour. As we describe in the online Appendix, we approximate hourly losses for service to residential customers by first estimating an OLS regression equation for annual average losses, controlling for the factors mentioned in the previous paragraph. Using these parameter estimates, for each utility, we then

¹⁶Lazar and Baldwin (1997) have a very accessible discussion of distribution line losses.

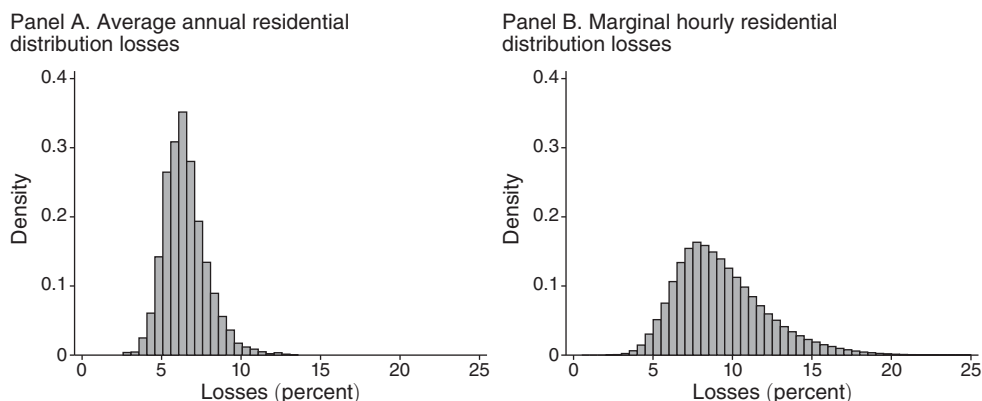


FIGURE 4. ESTIMATES OF RESIDENTIAL DISTRIBUTION LOSSES

predict the average losses for service to residential customers.¹⁷ The average loss rate is then converted to a time-varying hourly marginal loss rate on the assumption that 25 percent of losses are independent of flow (not marginal) and the remaining 75 percent are marginal losses allocated across hours in proportion to the square of load. The details are presented in the online Appendix.

To do this, however, we need data on the pattern of hourly consumption by residential customers, which don't exist for most utilities. FERC Form-714 provides hourly data on total consumption of all customers from groups of utilities, known as planning areas. We use that load profile, scaled by the share of total demand that comes from residential customers, to approximate the residential demand in each hour. This is not ideal. The alternative, however, is to use data produced with an engineering model of residential energy use patterns, which also is highly imperfect. As discussed in the online Appendix, we conduct a sensitivity using engineering-model-based data and it does not materially affect our results.

Distribution losses turn out to be significant in the overall analysis. Panel A of Figure 4 presents the spread of average annual distribution losses from residential customers for the utilities in our analysis. Table 3 shows that on a sales-weighted basis the estimated average distribution loss rate is 6.2 percent. Furthermore, because the externalities associated with electricity consumption take place upstream from the distribution losses, the loss rate scales up both the private marginal cost and the external marginal cost. After assuming that 25 percent of losses are nonmarginal and the other 75 percent vary with the square of load, panel B of Figure 4 presents the distribution of marginal hourly distribution losses from residential service that we estimate. These average about 8.9 percent, but vary greatly hourly with load.

¹⁷ As discussed in the online Appendix, the vast majority of our predicted average distribution losses for serving residential customers fall between 4 percent and 8 percent, with a mean of around 6.5 percent. Thus, the effect of marginal distribution losses on social marginal cost is overall about one-third larger than it would be if we had simply assumed that every utility had the national average loss rate of about 5.0 percent, but this approach also allows us to capture variation across utilities.

TABLE 3—SUMMARY STATISTICS OF DISTRIBUTION LOSSES

	Mean	SD	Min	P10	P90	Max
Avg. total losses (%)	4.90	1.33	0.55	3.36	6.55	10.44
Avg. res. dist. losses (%)	6.20	1.26	2.58	4.85	7.85	12.58
Marg. res. dist. losses (%)	8.87	1.82	3.75	6.95	11.15	18.23

Notes: $N = 6,215$ (utility-state-years). Statistics are sales-weighted.

B. Other Private Cost Considerations

The energy costs captured by the LMP and system lambda data used in this analysis constitute the great majority of the payments for wholesale electricity that are made by customers over the year. The remainder is made up of capacity payments, ancillary services costs, and other side payments known as “uplift.” Across the seven ISOs, energy costs comprised between 74 percent and 98 percent of the total wholesale payments for electricity in 2015, as shown in Table 4.¹⁸ More detail on the source and interpretation of these payments is provided in the online Appendix.

Capacity payments are regulatory-mandated payments from buyers to suppliers based upon their installed effective production capacity. We do not include capacity payments in our calculation of short-run private marginal cost. In some markets, such as ERCOT or SPP, there are no explicit capacity payments. In other markets that do have capacity requirements, the standards have to be adjusted in the medium or long run in response to variation in demand. These payments can sometimes be substantial. In 2015, capacity payments comprised between 4 percent and 22 percent of the total wholesale cost of electricity at the five ISOs that make these payments. Importantly, these payments move inversely to energy market revenues. When energy prices, reflecting short-run marginal costs, are high, capacity payments to generation implicitly or explicitly adjust to reflect the fact that generating plants are recovering more of their fixed costs through energy prices. In other words, capacity payments partially smooth the difference between long-run and short-run marginal cost.

The link between incremental consumption in a given hour and the capacity requirement is complex. However, conditioned upon the capacity at any point in time, the wholesale energy market price, adjusted for distribution losses, should reflect the true marginal resource cost of delivering one more kWh. Thus, from a strict economic efficiency vantage, longer-run investments triggered by current demand would not be a short-run marginal cost.¹⁹

We also do not incorporate the price of short-run operating reserve, or “ancillary services,” into our marginal cost calculation. LMPs are calculated in a process that

¹⁸ Our geographic results are grouped by NERC region. The geographic footprints of ISOs overlap those of the NERC regions, so it is difficult to make one-to-one mappings from an ISO to a NERC region.

¹⁹ One complication to this interpretation of short-run marginal cost arises when there is scarcity of supply. When electricity systems experience short-term violations of operating constraints, such as unit ramping or transmission flow constraints, prices include penalty values to reflect the cost of the scarcity of appropriate supply. To the extent these values do not reflect the true underlying value of electricity to end-users, they are rough approximations of the short-run marginal costs in these periods. There were relatively few such periods during 2014–2016.

TABLE 4—ESTIMATES OF THE COMPOSITION OF TOTAL WHOLESALE PAYMENTS

	Location	Energy (%)	Capacity (%)	Ancillary (%)	Uplift (%)
CAISO	California	89	9	1	1
PJM	Mid-Atlantic	74	23	2	1
ISO-NE	New England	81	15	3	1
NYISO	New York	74	22	3	1
ERCOT	Texas	92	—	4	4
SPP	Great Plains	98	—	1	1
MISO	Midwest	95	4	0	1

Note: Percentages may not sum to 100 due to rounding.

simultaneously optimizes for meeting demand and reserve requirements. The LMP therefore already reflects the shadow costs imposed through reserve requirements. The primary marginal impact of reserves is reflected in the energy prices or system lambda values used to reflect cost. This is because most reserves operate as standby resources and do not incur marginal cost unless a contingency event occurs. The main cost impact of an expansion of reserves arises when lower cost units are held back to provide reserves, while more expensive units are deployed to supply energy in their place. However this effect is captured in the marginal energy price when the more expensive units set those prices. In any event, these costs are relatively small, even in aggregate. In 2015, ancillary service payments at the seven ISOs comprised between less than 1 percent and 4 percent of the total wholesale cost of electricity.

Finally, some nonconvex incremental costs that are incurred to supply energy, such as generator “start-up” costs, are at times not captured in the energy price and are instead paid as out-of-market side-payments, or “uplift” payments to specific units. The funds for these side-payments are usually raised through a small fee applied to all demand.²⁰ We do not currently adjust our costs for these considerations. Again though, these payments are very small. In 2015, “uplift” payments range from less than 1 percent to 4 percent of the total wholesale cost of electricity.

Including all of the non-energy wholesale electricity costs would have a modest effect on the average wholesale price of electricity, and therefore on the gap between the marginal retail price and the average social marginal cost. It could, however, have a significant effect on the SMC during peak hours if reserve costs were considered marginal and were attributed entirely to the highest-demand hours. In that case, SMC would be more volatile than our analysis suggests and the deadweight loss of static pricing would be greater.

C. Private Marginal Cost Results

Figure 5 presents the private marginal cost calculations. Summary statistics on private marginal cost are presented in Table 5 in the next section along with external marginal costs and total social marginal cost. As discussed above, these private marginal cost levels are below what many consider to be the long-run average cost

²⁰ These costs are also not considered to be technically marginal, which is why they are not incorporated into market prices.

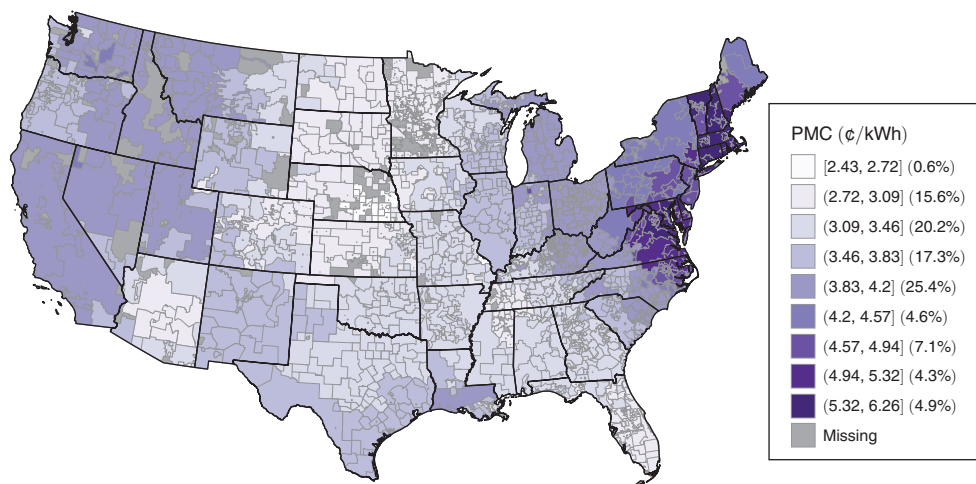


FIGURE 5. AVERAGE PRIVATE MARGINAL COST PER KILOWATT-HOUR

TABLE 5—ANNUAL AVERAGES OF PRICES AND MARGINAL COSTS

	Mean	SD	Min	P10	P90	Max
Retail variable price (P, ¢/kWh)	11.49	3.07	2.36	8.79	16.29	48.22
Private marginal cost (¢/kWh)	3.72	1.15	2.16	2.59	5.10	8.22
External marginal cost (¢/kWh)	6.21	2.38	2.50	3.04	9.38	12.12
Social marginal cost (SMC, ¢/kWh)	9.93	2.67	5.14	6.51	13.72	17.71
P-SMC (¢/kWh)	1.56	4.21	−9.39	−2.82	6.74	35.89
(P-SMC)/P	0.08	0.31	−3.47	−0.28	0.51	0.81

Notes: $N = 6,215$ (utility-state-years). Statistics are sales-weighted. Each observation is the hourly sales-weighted average value of the variable for a utility-state-year. These summary statistics are weighted across observations by the utility-state annual sales.

of power supply. In part, that reflects the fact that much of the country had excess capacity during 2014 to 2016 due to a combination of mistakes or bad luck in planning and policies of carrying large quantities of excess capacity. Private marginal cost below long-run average cost also reflects the fact that in most deregulated markets, power plant owners receive revenues from capacity payments as well as energy payments. Regardless of whether such capacity payments are appropriate, they do not reflect marginal cost and therefore can distort consumption when reflected in marginal consumer prices.

There is also significant variation over time in these levels. Figure 6 summarizes the monthly average wholesale private marginal cost by NERC region.²¹ During winter periods of high demand and gas prices, such as the 2014 polar vortex, PMC and prices rose to extremely high levels, raising monthly averages above \$0.15/kWh in parts of the Mid-Atlantic (RFC) and northeast (NPCC) regions. This pattern reflects, on a longer time-scale, many of the issues raised in discussions of

²¹ We have combined California with the rest of the WECC and Florida (FPCC) with the neighboring SERC region in order to make the figure more readable. The regions that we combined have very similar price patterns.

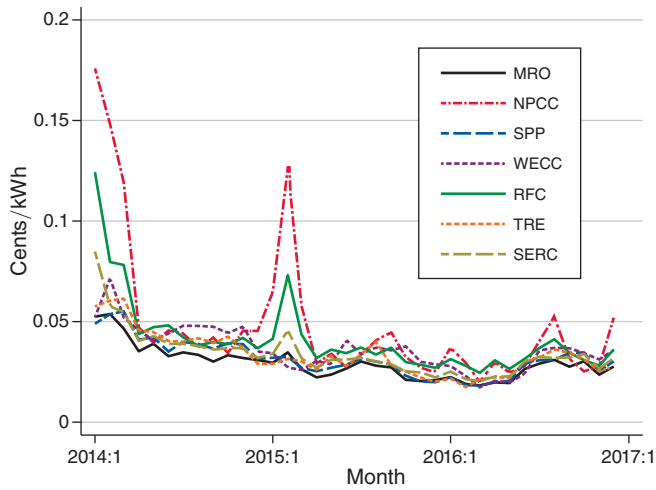


FIGURE 6. MONTHLY PRIVATE MARGINAL COST BY NERC REGION

short-run dynamic electricity pricing. Marginal costs in power markets are quite volatile, even on a monthly or annual basis.²² The electricity industry has experienced repeated cycles where marginal costs move dramatically relative to average cost (Borenstein and Bushnell 2015), while retail prices, which are strongly linked to historical average cost, are significantly more rigid.

Wholesale prices (and implied private marginal costs) that remain for long periods below levels necessary to cover long-run average cost are certainly a concern for generators and policymakers. However, even if measured accurately, such a shortfall does not have direct bearing on our analysis of the efficiency of residential retail marginal prices and their deviation from SRSMC. Economic theory dictates that if short-run marginal costs are indeed quite low, then efficient pricing should reflect that, even if such prices are not sufficient to cover average cost.²³ Furthermore, even if policymakers believe that additional revenue must be raised in order to cover the past investments of suppliers, such revenues need not come from marginal energy prices. Fixed charges, subscription charges (e.g., based on the customer's circuit breaker capacity), demand charges (e.g., based on the customer's maximum hourly demand), or government subsidies are among the alternatives that can be used to increase revenue collection without raising marginal price, though these alternatives can also create distortions.

²²In contrast to other energy markets, such as oil, the level and volatility of wholesale electricity prices can differ substantially between regions because transmission losses, limits on transmission capacity, and high storage costs limit the ability to arbitrage wholesale electricity prices and costs between regions and over time. In the case of Texas, a higher cap on spot prices also leads to a more extreme distribution of prices.

²³And, conversely, if the marginal generation costs are quite high, yielding very high profits for producers (but without exercise of any market power), then efficient retail prices should reflect those high short-run marginal costs.

IV. External Marginal Costs and Total Social Marginal Costs

For external marginal cost, we build on Graff Zivin, Kotchen, and Mansur (2014) and Holland et al. (2016), as well as the newer Air Pollution Emission Experiments and Policy (AP3) pollution damage model (see Clay et al. 2019) to estimate the marginal damages associated with a change in load. We do this analysis for the same nine US regions introduced in Section III. The details of the estimation are in the online Appendix. In brief, for each of the four major pollutants from electricity generation (CO_2 , SO_2 , NO_x , and $\text{PM}_{2.5}$), we create a variable that is total emissions damages by hour of the three-year sample for each of the nine regions, incorporating the operations of each fossil fuel power plant and the damages associated with emissions from each plant, based on the AP3 damage model for 2014.²⁴ In this analysis, we assume that the “social cost of carbon” (SCC)—the net present value of damages resulting from additional emitted CO_2 —is \$50 per metric ton. In the online Appendix, we present the results of an analysis with the SCC assumed to be \$100 per ton. It is worth noting that national adoption of a substantial carbon price would disproportionately affect areas with high CO_2 emissions which are mostly areas in which retail price is lower than SMC.

We then regress each pollutant damage variable on piecewise linear functions of the load within the same region and the load in the other regions that are part of the same grid interconnect (Western, Eastern, and Texas). The regressions are estimated in 24-hour differenced form, so identification is based on the change in emissions from day to day in response to a change in load. The coefficients of these regressions can be interpreted as estimates of the marginal damage from a change in load in one region as a function of the load level in that and interconnected regions.

We use these coefficients to construct the damage associated with marginal electricity consumption in each of the nine regions for each hour of the sample. We do make two small adjustment to these damage estimates. The first involves scaling up the calculations of pollution associated with a marginal end-use kWh to account for distribution losses as discussed above. The second involves adjusting down our estimates of external costs to account for any policies that incorporate externality costs into electricity prices, such as carbon cap-and-trade programs. The resulting aggregate damages from incremental quantity consumed in each region are shown in online Appendix Table A1. The results show that CO_2 is consistently a major contributor to the external marginal cost, but in areas with high levels of coal-fired generation, SO_2 tends to impose as much or more cost.

²⁴ The AP3 model links county-level emissions of criteria air pollutants and greenhouse gases to an air transport model and physical damages in order to establish costs of emissions by pollutant/county. It incorporates assumptions about dose-response of various pollutants and value of a statistical life. For more information, see <https://public.tepper.cmu.edu/nmuller/APModel.aspx>. Our external marginal cost analysis does not incorporate emissions upstream of the power plant, in either fossil fuel extraction or transportation. The extent of externalities from extraction and transportation, particularly for natural gas, is the subject of widely divergent views. See Alvarez et al. (2018) and Jha and Muller (2018). Including these upstream externalities would increase external marginal costs and decrease price minus social marginal cost.

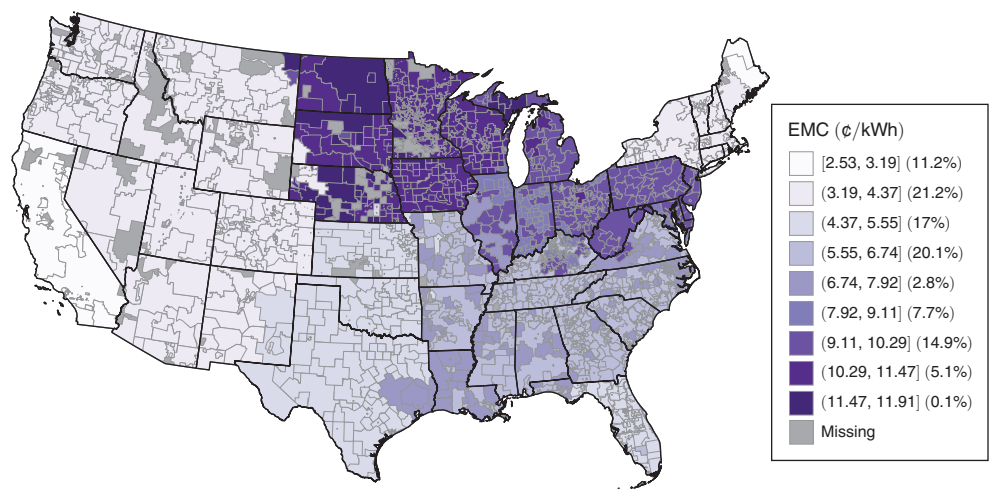


FIGURE 7. AVERAGE EXTERNAL MARGINAL COST PER KILOWATT-HOUR

A. External Marginal Cost Results

In Figure 7 we show the average externality cost per kWh. The figure shows the average dollar-value externality cost associated with a marginal kWh of demand change in each location. The figure illustrates some coarseness in these data, because the analysis assumes that the same plants are marginal for any incremental demand within each of the nine regions for a given hour of the sample regardless of the location of the incremental demand in the region. Still, the figure demonstrates that externality costs vary widely and are particularly large in the areas where coal-fired power plants are most prevalent. Comparing the scales of Figure 5 and Figure 7 also indicates that the majority of the social marginal cost in our calculations in most locations is due to externalities, rather than the private marginal cost of generation.

B. Total Social Marginal Cost Results

Figure 8 then aggregates the data in Figures 5 and 7 to present the average social marginal cost. Though California has among the higher private marginal costs, the external marginal cost associated with that generation is much lower than in most of the United States, causing it to have among the lowest SMCs. In contrast, the upper Midwest has low PMC, but such high EMC that it exhibits a very high SMC. Table 5 shows that the average quantity-weighted social marginal cost is \$0.099 per kWh, nearly two-thirds of which is due to external marginal costs.

V. Mispricing and Deadweight Loss

Figure 9 presents the marginal price minus average social marginal cost map. The bluer areas are pricing above average SMC, while the redder areas are pricing below average SMC. Much of the country has fairly light colors, indicating that the

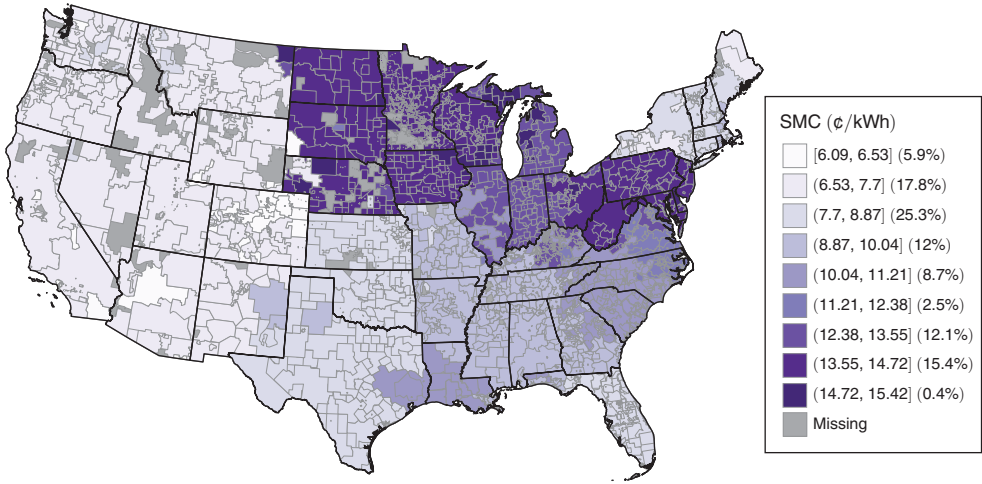


FIGURE 8. AVERAGE SOCIAL MARGINAL COST PER KILOWATT-HOUR

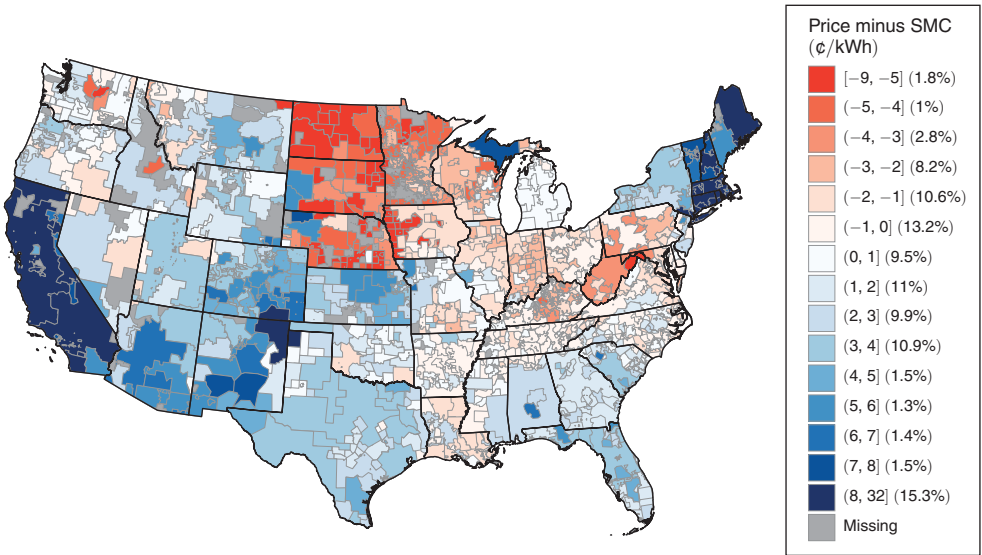


FIGURE 9. MARGINAL PRICE MINUS AVERAGE SOCIAL MARGINAL COST PER KILOWATT-HOUR

static marginal price that residential customers pay is fairly close to average SMC. California and parts of New England are notable for price being well above SMC, while parts of the Dakotas, Nebraska, and Minnesota exhibit the largest price deviations below SMC. In the legend, the percentages in parentheses are the share of residential customers in each category.

Figure 9, however, captures only part of the story, because it does not include variation in SMC over time. The static price might reflect the average SMC well, but still create significant inefficiency because the SMC varies substantially hour-to-hour.

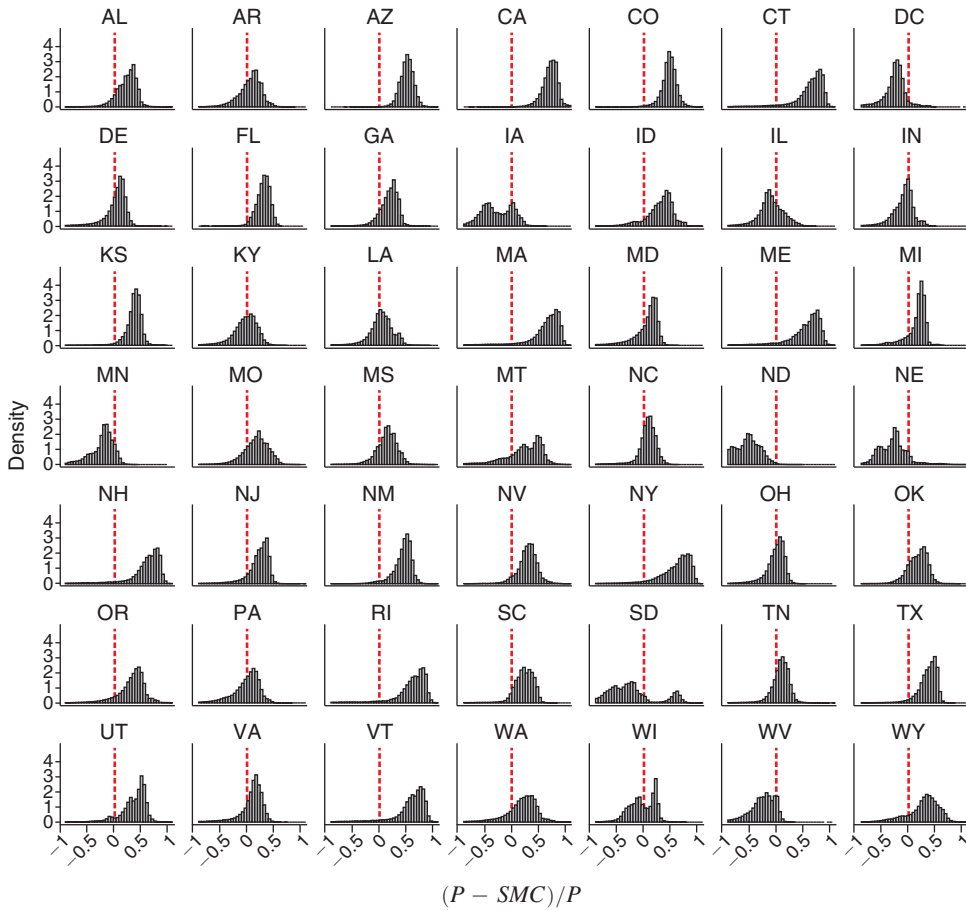


FIGURE 10. HOURLY PRICE MARKUP $\left(\frac{P - SMC}{P}\right)$ BY STATE

Figure 10 shows histograms by state of the hourly markup, $\frac{P - SMC}{P}$, illustrating that SMC varies quite widely in some states, while it varies much less in others.

A. Analyzing Deadweight Loss

In order to study the social cost of electricity mispricing, we next analyze deadweight loss (DWL) directly. As discussed above, residential retail electricity pricing departs from efficiency both by charging a single time-invariant price—rather than allowing price to change hourly or more frequently as social marginal cost changes—and by setting that single price at a level substantially different from the average social marginal cost. We decompose mispricing into these two components and allow different demand elasticities, a “short-run” elasticity that reflects consumer response to high-frequency price variation and a “long-run” elasticity that reflects consumer response to changes in the long-run average price they face. A detailed explanation of these calculations is in the online Appendix.

Estimates of demand elasticity vary substantially in the literature, but there seems to be widespread agreement that demand elasticity is dependent on technology and the longevity of price variation. In the last decade, these elasticities very likely have increased with improved alternatives, from end-user batteries to advances in technology for automated price response (Gerke et al. 2020). This trend is likely to continue with higher levels of electric vehicle adoption. Long-run electricity demand elasticity has generally been thought to be greater than short-run elasticity (Zhu et al. 2018), but that could change in the future as technology allows time-shiftable uses to be moved away from the highest priced hours, including water heating, dish and clothes washing and drying, and to some extent even space heating and cooling (through preheating and precooling).²⁵ Rather than base our conclusions completely on one set of demand elasticity estimates, we present results for a base illustration of a short-run elasticity of -0.2 and a long-run elasticity of -0.5 —which are approximately the median estimates found in a recent meta-analysis (Zhu et al. 2018)—but in the online Appendix we include results for a wide range of possible elasticities.

DWL calculations are also a function of how SMC changes with quantity. Consistent with discussion of externalities above, we have estimated an SMC elasticity with respect to quantity at the NERC region level, which we detail in the online Appendix. We find, however, that the range of quantity changes that result from the price variation and assumed demand elasticities are associated with minuscule changes in SMC and have almost no effect on our DWL calculations. Thus, for computational simplicity, we assume that SMC is constant over the range of the quantity changes considered.

DWL from mispricing electricity is also potentially influenced by mispricing of other goods in the economy, most importantly substitutes for electricity such as natural gas and gasoline (Davis and Muehlegger 2010; Borenstein and Davis 2012). In follow-on work (Borenstein and Bushnell 2022), we investigate distortions in pricing these substitute energy sources. Though we find that US gasoline is generally underpriced relative to SMC and natural gas is generally overpriced, on an energy-equivalent basis the deviations for both are far smaller in absolute value than for electricity.²⁶

We calculate total DWL based on the departure from efficient pricing equal to the hourly SMC. The component of DWL that is due to charging a static price equal to the quantity-weighted average SMC at all times, rather than hourly SMC, is calculated using the short-run demand elasticity.²⁷ The component of DWL due to charging a static price that deviates from the quantity-weighted average SMC is then calculated using the long-run demand elasticity.

Figure 11 presents the histogram of total DWL per kilowatt-hour. To avoid biasing the calculation due to the endogeneity of quantity to $\bar{P}$, however, each utility's

²⁵ As this discussion suggests, a complete analysis of DWL from electricity mispricing would require estimation of the full matrix of own- and cross-price elasticities across hours, an extremely challenging task that we leave for future research.

²⁶ We exclude congestion and accident externalities from the gasoline calculations, assuming those would be approximately unchanged if vehicles were powered with electricity.

²⁷ Borenstein and Holland (2005) show that the DWL-minimizing static price is the quantity-weighted average SMC if demand elasticity is static or if time-varying demand elasticity is not correlated with time-varying SMC.

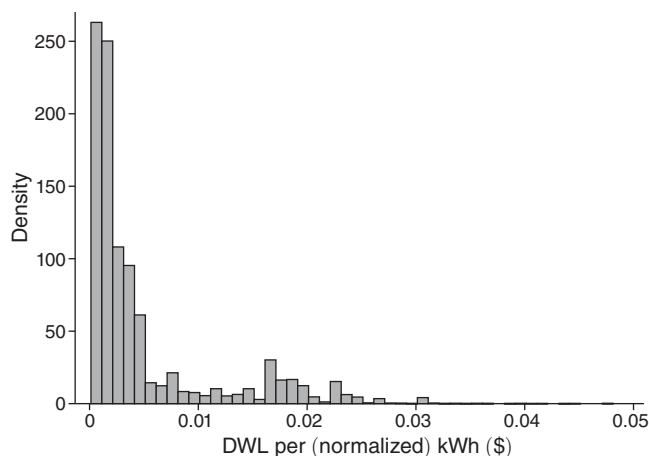


FIGURE 11. DISTRIBUTION OF DEADWEIGHT LOSS PER NORMALIZED KILOWATT-HOUR

quantity of kilowatt-hours is normalized to the quantity it would have sold at $\bar{P} = \overline{SMC}$ given the assumed long-run elasticity. The histogram is also weighted by these normalized quantities. The results presented show that most utilities exhibit fairly low DWL per unit demand, compared to an average SMC of about \$0.10 per kWh, but a few show much higher DWL. Figure 12 shows the histogram of utility $DWL/\overline{SMC}$. This ratio also is quite low for most utilities, but for some it is 0.2–0.4, suggesting that, at these demand elasticities, mispricing dissipates as much surplus as would a 20 to 40 percent increase in the social marginal cost of supplying electricity.²⁸

For this base case, about 77 percent of the total DWL is a result of the long-run response, that is, the failure to set $\bar{P} = \overline{SMC}$, with the remainder attributable to the absence of real-time price variation. The larger assumed long-run elasticity is partially responsible for such a high share. If the short-run and long-run elasticities are set equal to one another, in the -0.1 to -0.9 range, then 57 to 62 percent of the DWL would be attributed to the long-run response.

So, the answer to our title question is that two pricing wrongs do indeed make a (mostly) right for most utilities. One might ask whether this is because each pricing wrong is relatively small or whether it is a serendipitous result of offsetting “wrongs.” To address this question, we carry out a similar DWL analysis as above, but with each of the pricing wrongs separately. First, we consider how large DWL would be if there were no environmental externalities so that SMC were equal to PMC in every hour.²⁹ Second, we consider how large DWL would be if there were

²⁸ California’s three large investor-owned utilities are among these outliers. Together they make up 8 percent of the total US residential normalized quantity (at a long-run elasticity of -0.5), but are responsible for 31 percent of the DWL.

²⁹ We don’t adjust retail price, because nearly all of the deviation of retail price from $\overline{PMC}$ is unrelated to expenses associated with environmental control or remediation. Even in California, Borenstein, Fowle, and Sallee (2021) find that a small share of the gap between residential retail price and SMC is attributable to environmental mandates, though it is difficult to know how much is due to climate change adaptation.

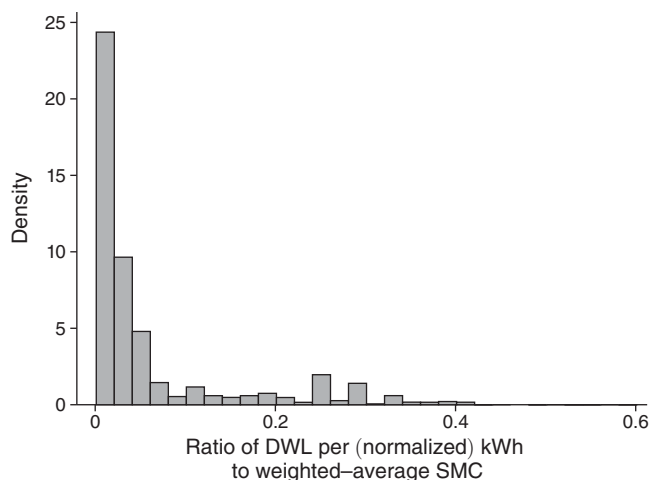


FIGURE 12. DISTRIBUTION OF DWL/SMC RATIO

environmental externalities, but utilities set a static volumetric price equal to $\overline{PMC}$, perhaps by imposing substantial monthly fixed charges.

Figure 13 presents the (normalized) quantity-weighted distribution of DWL for the base case and these two alternative cases with only one of the pricing wrongs. It makes clear that the low DWL in the base case is the result of a lucky coincidence of the two offsetting distortions. With both distortions, the mean DWL per normalized quantity is \$0.005 per kWh, but with either distortion alone, it is about five times higher, \$0.023 with no environmental externalities and \$0.027 with environmental externalities and price set equal to $\overline{PMC}$. With either distortion alone, the DWL from mispricing dissipates on average about as much surplus as would a 25 percent increase in SMC.

VI. Applications and Implications

Having calculated estimates of both the marginal prices and marginal social costs of electricity, we now consider some policy areas where such information ideally would be considered, and the implications of our calculation for such policies. One area where our calculation has potential relevance, but has received limited policy attention in the United States, is the application of carbon pricing to the electricity sector. As discussed above, policy debates over the design of carbon pricing policies periodically invoke the Pigouvian ideal of capturing the marginal externality costs of greenhouse gases in consumer energy prices. Mechanisms such as output-based updating of allowance allocation, and the application of intensity standards, have been criticized on the grounds that they dilute the externality cost faced by consumers (Holland, Hughes, and Knittel 2009; Fowlie 2012).

However, if marginal prices are already above social marginal cost, the additional externality signal only pushes prices further away from first best. It is worth noting that in the United States, carbon pricing—in the form of cap-and-trade—is currently applied to electricity only in California and the Northeastern states comprising the

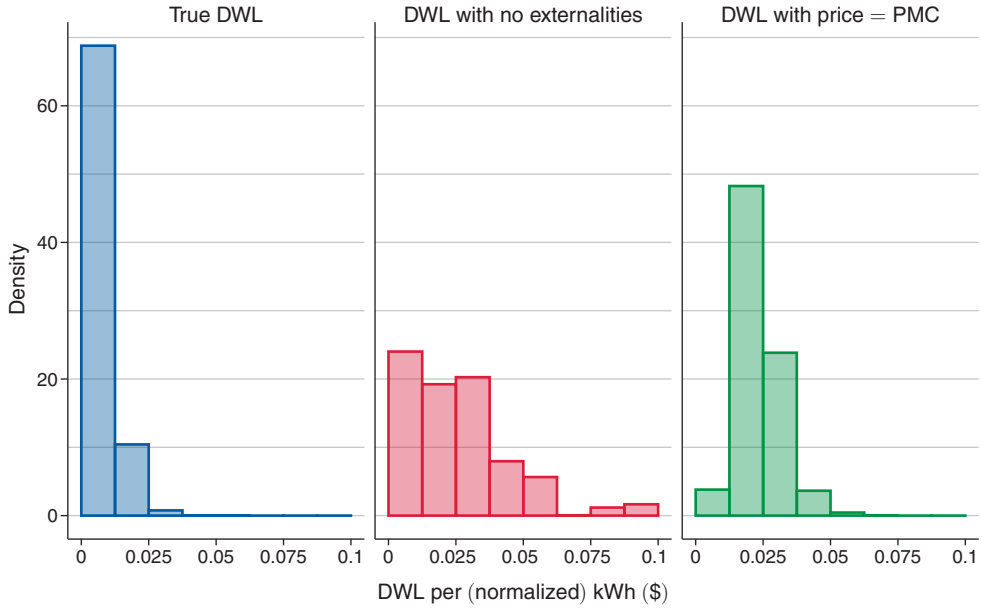


FIGURE 13. DISTRIBUTION OF DWL PER NORMALIZED KILOWATT-HOUR WITH ONE OR BOTH PRICING WRONGS

Regional Greenhouse Gas Initiative. However, these are the collection of states where we have found average retail prices to be well above social marginal cost.

Still, it is important to recognize that our analysis focuses only on the distorted consumption incentives when residential retail price deviates from social marginal cost. We have not studied commercial and industrial rates, which are more complex, with greater use of time-varying pricing and demand charges that determine (and distort) customer incentives. More importantly, our analysis does not consider the effect of market mechanisms for greenhouse gases and other pollution externalities on the mix of generation, between coal-fired generation, gas-fired generation, nuclear power, renewable generation and other sources. The efficiency value of pricing emissions at the wholesale level seems likely to be quite significant. Our findings, however, suggest that the argument for passing through those costs to residential rates is much weaker in some parts of the country.

Our findings also have direct implications for two other areas that have received considerable attention in the energy and economics literature: energy efficiency and distributed energy resource policy. We explore each of these in turn. We do not attempt here to perform a detailed calculation of the welfare implications of these policies, but rather present suggestive evidence that efforts in both areas may be significantly geographically misaligned with the benefits they can provide.

A. Energy Efficiency

The subject of energy efficiency in general, and its role in the electricity industry in particular, has been a topic of debate among economists and technologists for

decades. Much of the debate has focused on whether these programs deliver the reduced energy consumption claimed by the utilities that implement them (Joskow and Marron 1992; Auffhammer, Blumstein, and Fowlie 2008). Economists have also examined the specific behavioral, regulatory, and market channels that could justify energy efficiency policies (Allcott and Greenstone 2012; Gillingham and Palmer 2014). However, much of the literature on the “efficiency gap” has focused on what Gerarden, Newell, and Stavins (2017) call the “private energy-efficiency gap”—the question of whether customers are making individually rational economic choices. They note that the more policy-relevant question of the social energy-efficiency gap hinges on many factors, including the relationship of energy prices to social marginal cost, a question they identify as a “relatively high priority” for further research. Indeed, well-informed consumers who face retail prices that are significantly above social marginal cost are already being given too much incentive to adopt energy efficiency measures. If consumers are able to make privately optimal energy-efficiency decisions, government programs to promote improved energy efficiency would be best aimed at areas where price is below social marginal cost, and could be welfare-reducing where price is well above social marginal cost.

Several recent papers have attempted to address aspects of the relationship between energy efficiency programs and the social benefits they provide. Both Novan and Smith (2018) and Boomhower and Davis (2020) examine the impact of energy efficiency programs on the hourly profile of energy use, and compare those impacts to wholesale power costs and environmental impacts.

Using state-level data from the Consortium for Energy Efficiency,³⁰ we examine per-customer reported expenditures on residential energy efficiency programs.³¹ This includes both energy efficiency programs run through utilities and those run through non-utility organizations, which play a significant role in New York, Oregon, Vermont, and parts of California, for instance. Other efficiency measures, such as appliance and building standards, impose costs on firms and consumers that are also not captured in these data. Still the data presented here are strongly reflective of the relative emphasis that different jurisdictions place upon energy efficiency measures. Figure 14 illustrates the annual state-level expenditures per customer of electric utilities on energy efficiency programs. The largest expenditures are focused on the coasts, with particular intensity in California and the Northeast. According to our calculations, these are the regions where marginal energy efficiency expenditures provide the least, possibly even negative, social value. Clearly, the distribution of spending on energy efficiency within the United States is suboptimal at best.³²

³⁰ <https://www.cee1.org/annual-industry-reports>.

³¹ Our thanks to Hunt Allcott for suggesting this comparison.

³² This discussion assumes that the purpose of energy efficiency programs is to reduce consumption because $P < SMC$ gives incentives for excessive consumption. To the extent that these programs have other goals—such as correcting non-optimizing private consumption choices caused by principal-agent incentive conflicts, imperfect information, myopia, or irrationality—these other goals would also need to be considered.

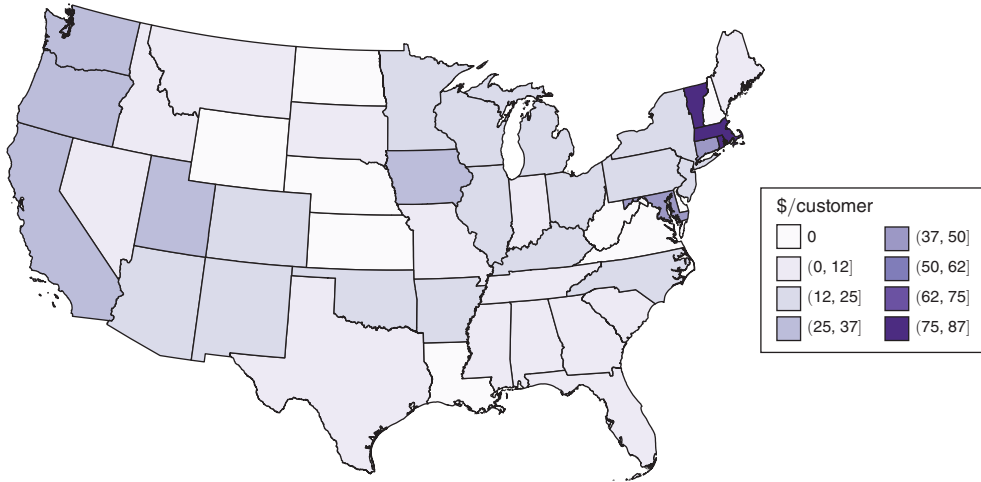


FIGURE 14. ELECTRIC UTILITY EXPENDITURES ON ENERGY EFFICIENCY PROGRAMS

B. Rooftop Solar Policy

Another area of energy policy that is directly impacted by the relationship between retail prices and marginal cost is the deployment of small-scale distributed energy resources. Small-scale generation resources, currently overwhelmingly comprised of rooftop solar photovoltaic (PV) installations, are deployed “behind the meter.” Most of these systems are generally eligible for “net metering,” meaning that when a customer’s production exceeds consumption in an hour, the excess production is allowed for billing purposes to offset excess demand in other hours. This allows residential customers with distributed generation to offset the full retail price of electricity, rather than the marginal replacement cost of the energy that is produced. Where retail variable prices substantially exceed the marginal cost, residential solar is considerably more attractive for consumers. In California, Borenstein (2017) calculates that the gap between retail and wholesale marginal electricity prices means that net metering provides about as large an incentive for residential solar as the 30 percent federal investment tax credit.

Drawing again from the EIA Form-861, we aggregate the capacity of distributed resources that is subject to net metering by utility reporting area. Figure 15 illustrates the capacity of distributed generation (in watts) per customer for the utility systems that report this statistic to the EIA. California, with over 40 percent of the residential solar capacity in the nation, again dominates this calculation.

The map reflects the union of at least three sets of attributes: significant solar incentives (e.g., New Jersey), solar potential (desert Southwest), and high retail prices. Comparing Figure 15 to Figure 10, the strong relationship between high retail prices and solar deployment again stands out. A full calculation of the welfare implications of retail tariffs on distributed generation would require a decomposition of rate effects from other incentives, as well as estimates of the relative efficiency of solar deployment in different locations. However, Figure 15

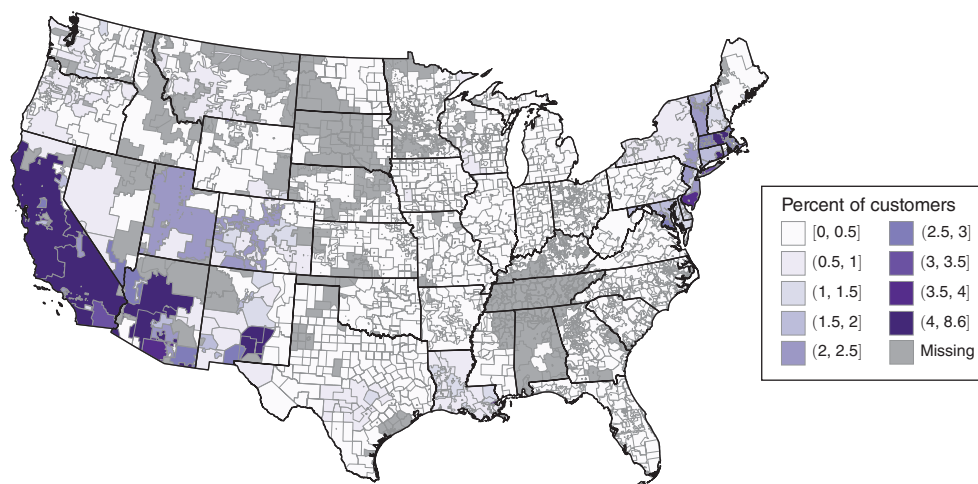


FIGURE 15. PERCENTAGE OF RESIDENTIAL CUSTOMERS WITH ROOFTOP SOLAR

Notes: This figure shows the proportion of residential customers under a “net metering” tariff, which allows a customer to sell their own generation to the grid at retail prices. Virtually all customers with rooftop solar are covered by net metering and virtually all residential net metering is associated with rooftop solar.

does suggest that expenditures on distributed solar are strongly associated with retail price incentives that greatly exceed the social value of distributed generation.

The deployment of distributed energy resources, and the resulting reduction in metered consumption, known as “load defection,” is a growing threat to the finances of distribution utilities who have been recovering capital cost through volumetric rates. Critics and proponents of small-scale distributed generation have battled over net metering policies, but net-metering policies lose their relevance if the marginal retail rate reflects social marginal cost. Recognizing this fact, utilities are increasingly seeking to adjust their rate structures to increase monthly fixed charges and reduce their volumetric prices. While not a panacea (Borenstein 2016), a shift toward larger fixed fees, particularly in states like California where they are modest to nonexistent, would partially insulate utilities from the loss of customer load and reduce the marginal private reward of solar deployment for customers.

Consideration of distributed generation also raises questions of their potential impact on distribution losses and other costs associated with distribution networks, such as voltage support. As discussed above, marginal distribution losses can be significant, reaching over 20 percent at times, which distributed generation could mitigate or exacerbate depending on location and timing of production. More generally, the degree to which optimized location and control of distributed resources could change the cost of distribution remains an important area of research. Collection of distribution-level data with higher temporal and locational resolution could help address these questions.

VII. Conclusion

Most policy recommendations from economists for responding to the challenge of climate change focus on “getting the prices right.” But in retail electricity markets, the prices are wrong for many reasons beyond greenhouse gas emissions. In this paper, we have analyzed the direction and degree of mispricing in residential electricity.

We find that with the current generation capacity and remuneration mechanisms for generation, the short-run private marginal cost was quite low during the period 2014–2016, a (quantity-weighted) average of less than \$0.04 per kWh, which is below most estimates of the long-run average cost that generation must cover to support new investment. Estimates of the average externalities associated with generation are nearly twice the level of private marginal costs. We show that distribution-level marginal line losses significantly increase both of these costs, by about 9 percent on average. Accounting for private and external marginal costs, and adjusting for distribution line losses, we find large variation in full societal marginal cost from a (quantity-weighted) tenth percentile of \$0.065 per kWh to a ninetieth percentile of \$0.137 per kWh.

Somewhat surprisingly, we find that across the country about 39 percent of residential sales at a time-invariant marginal electricity price are below the utility’s average social marginal cost of providing electricity. But we find wide variation, with prices well above average SMC in California and the Northeast, and below in much of the Midwest and the South.

That comparison, however, captures only part of the inefficiency, because social marginal cost varies hour to hour while price does not for nearly all residential customers. Using median short-run and long-run demand elasticity estimates from a recent meta-study, we find that about three-quarters of the total DWL from electricity mispricing is due to setting a time-invariant price at an inefficient *level* while the other one-quarter is attributable to the failure to change retail prices dynamically as SMC changes. These proportions, however, are highly dependent on relative short-run and long-run elasticities, which we note are likely to change as consumer technologies evolve.

Nonetheless, the largest DWL today likely results from a small number of utilities, mostly in California, setting prices well above average SMC. In most of the country, we find that retail price is fairly close to SMC, creating relatively little DWL. We show, however, that this is a serendipitous outcome of the two pricing wrongs referenced in our title, with underpricing due to unpriced externalities on average about balancing out overpricing due to the recovery of significant fixed costs through volumetric prices. Our analysis suggests that if either there were no unpriced externalities or fixed costs were recovered through other charges or revenues so that price equaled private marginal cost, (quantity-weighted) average DWL would be about five times greater.

Our findings have implications not just for standard deadweight loss analysis of consumption, but also for common related policies on residential energy efficiency and distributed generation. Many states have aggressive programs to encourage such investments, but if prices already exceed social marginal cost, the value of additional

investments beyond those that well-informed individuals would already choose to make is questionable. It is perhaps not politically surprising, but nonetheless economically concerning, that we find these programs are most prevalent in areas where retail prices are already substantially above social marginal cost.

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