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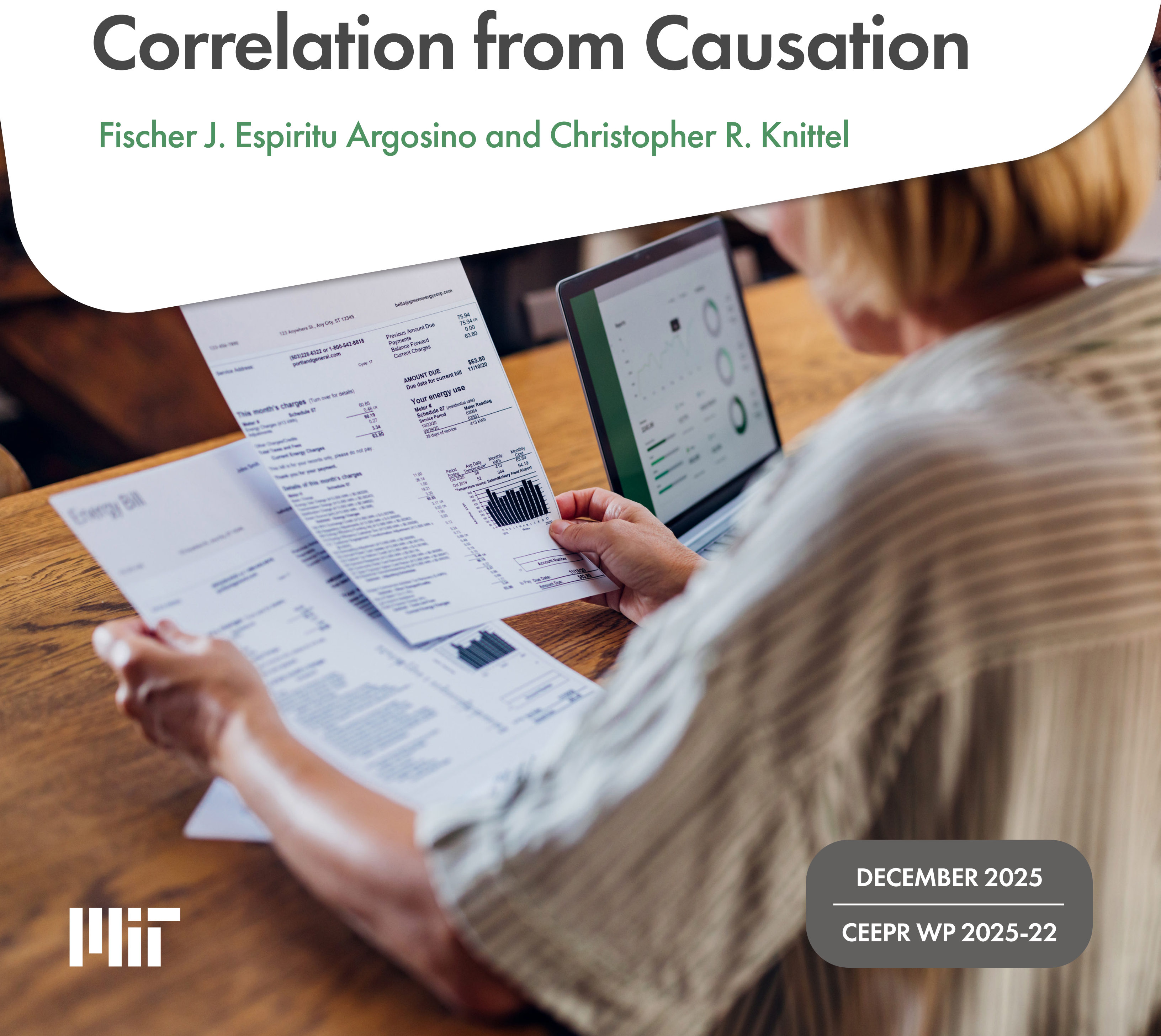
Fischer J. Espiritu Argosino and Christopher R. Knittel



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Renewables and Electricity Affordability: Untangling Correlation from Causation

Fischer J. Espiritu Argosino and Christopher R. Knittel*

December 1, 2025

Abstract

Rising electricity prices have become a salient policy concern amid broader inflationary pressures in the U.S. economy. Many observers, including policymakers and the public, have attributed these increases to renewable energy policies such as Renewable Portfolio Standards (RPSs) or to the growth of wind and solar generation. Using a panel of U.S. states and a fixed-effects econometric design, we test whether these apparent correlations persist after controlling for time-invariant state characteristics and common temporal shocks. We find that once both state and year effects are included, the association between RPS stringency and retail electricity prices disappears, suggesting that the raw correlation is not causal. Utility-scale wind and solar generation are, if anything, weakly associated with *lower* prices. Rooftop solar adoption, however, remains positively correlated with rates, likely due to cost-recovery mechanisms embedded in retail tariffs. Beyond renewables, there are two additional factors that may be driving rate increases: climate-driven grid hardening and the rapid growth of data centers. Recent work suggests climate change is a factor; our ongoing work studies the role of data centers. These results highlight the need for equitable rate design and targeted resilience investments rather than a retrenchment of renewable policy.

* *Argosino*: Graduate Student, MIT Center for Energy and Environmental Policy Research and MIT Technology Policy Program, espargo@mit.edu. *Christopher R. Knittel*: George P. Shultz Professor and Associate Dean for Climate and Sustainability, Sloan School of Management, Director, MIT Center for Energy and Environmental Policy Research, Director, MIT Climate Policy Center, and NBER, knittel@mit.edu.

1 Introduction

Electricity prices have emerged as a defining policy concern across the United States. In an era of persistent inflation, households are contending with higher prices for groceries, housing, insurance, and transportation. Against this backdrop, rising electricity bills have drawn intense public scrutiny and political attention. Press coverage has reflected this anxiety: major outlets have run stories such as "Americans have looked aghast at their rising electricity bills — and found one clear scapegoat: data centers"[1], while op-eds counter that "green policy is to blame"[2], citing Renewable Portfolio Standards (RPSs) and other decarbonization mandates. State regulators and legislators are meanwhile rewriting distributed-solar tariffs, and utilities are submitting multi-year plans to harden the grid against storms and wildfires.

Behind these headlines lies an urgent analytical question: are renewable energy policies actually driving higher retail rates, or do these correlations mask deeper structural and environmental forces? The stakes are significant. Electricity affordability influences consumer welfare, regional competitiveness, and the political durability of climate policy. Understanding the true drivers of rate changes is essential for designing equitable and economically efficient decarbonization pathways.

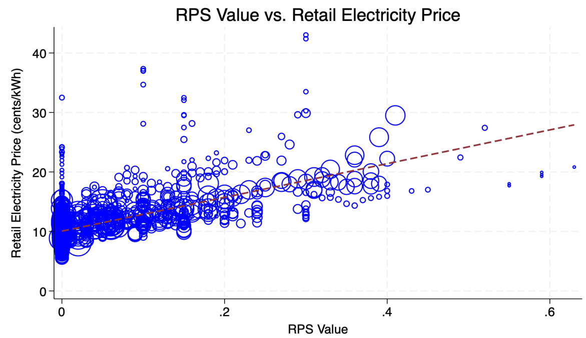
At first glance, the data appears to validate the popular suspicion. Scatterplots of state-level retail electricity rate changes against both renewable penetration and RPS stringency show a clear, positive correlation: states with higher renewable shares or stricter standards tend to have higher electricity prices. These figures, often reproduced in media coverage and policy debates, present an unmistakable pattern. But as economists caution, such simple correlations can mislead. They do not tell us which direction the causality runs—or whether another force entirely is driving both renewables and rates upward. Establishing causation requires us to move beyond these raw associations.

The raw data patterns are clear in Figure 1. Each panel plots hollow, blue bubbles whose sizes are proportional to total generation (so higher-generation observations are visually emphasized), with a maroon dashed line showing the generation-weighted linear fit. Across all four panels, there is a visible positive association in the cross-section. The association is most pronounced for rooftop solar share, while the utility-scale wind and solar panels show a more modest slope in the raw data. As emphasized below, however, correlation is not causation; these patterns motivate—but do not settle—the question of whether renewables or renewable policies *cause* higher retail prices once

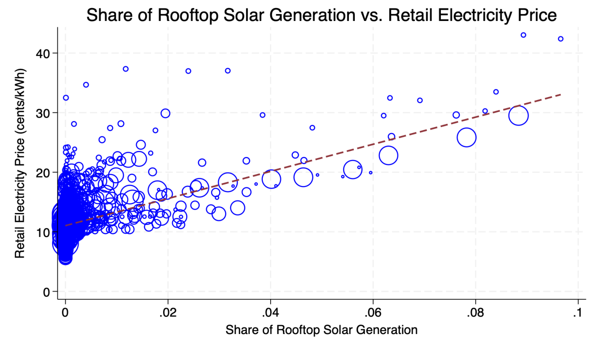
[1]The New York Times, "Data Centers Are the New Villains for Rising Electricity Prices," , Oct. 2025.

[2]The Wall Street Journal, "Electricity Prices Are Going Up. Green Policy Is to Blame," Oct. 2025.

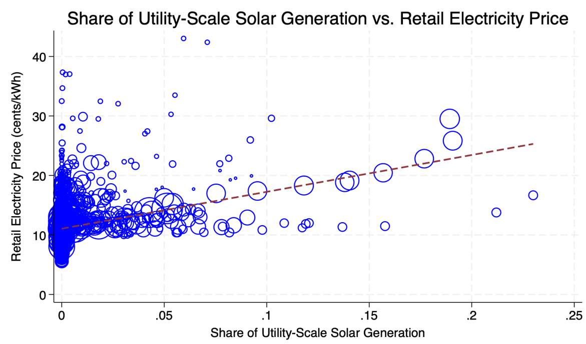
confounders are controlled.



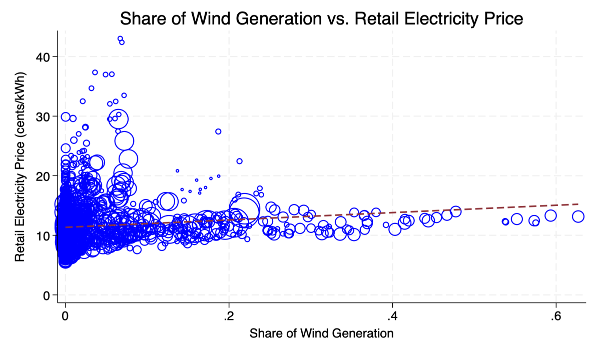
(a) RPS Value vs. Retail Electricity Price



(b) Share of Rooftop Solar Generation vs. Retail Electricity Price



(c) Share of Utility-Scale Solar Generation vs. Retail Electricity Price



(d) Share of Wind Generation vs. Retail Electricity Price

Figure 1: Raw cross-sectional correlations: hollow blue bubbles (size $\propto$ total generation) and maroon dashed generation-weighted OLS fit. These figures illustrate correlation in the raw data and motivate the econometric analysis in Section 1.

When two variables—renewable deployment and electricity rates—move together, three broad causal channels can explain the pattern. First, renewables or renewable policies might genuinely *cause* higher rates, for example, through cost recovery of capital investments or policy surcharges. Second, higher rates could *induce* renewable adoption and policy ambition, if expensive electricity motivates political or household responses. Third, there may be some factors that drive both: fuel mix, legacy infrastructure costs, or local climate risk could jointly influence electricity prices and policy choices. Untangling these channels requires careful econometric analysis rather than simple correlations.

Policymakers are simultaneously grappling with a complex policy landscape. The majority of states now have some form of renewable target, clean-energy standard, or distributed-generation program. California's transition from net-metering to "net billing" (NEM 3.0) reduced rooftop-solar export credits and sparked debate over fairness and cost shifts. North Carolina, Illinois, and other states are considering similar reforms. At the federal level, the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA) under the previous administration were channeling tens of billions of dollars into grid modernization and resilience; meanwhile, the current Administration has signed executive orders intended to reshape the regulatory and cost environment of renewables and fossil fuels.[3] Simultaneously, the new administration issued a declaration of a national energy emergency on day one.[4]

These developments have shaped a polarized narrative. Critics of renewables often point to state-level maps where RPS adoption and high retail rates coincide, while advocates note that such comparisons fail to account for confounding factors such as fuel prices, legacy infrastructure, and local demand conditions. The empirical challenge, then, is to determine whether renewables or renewable policies *still* predict higher electricity rates once we control for other potential drivers.

Recent analyses by Wiser et al. (2025) and O'Shaughnessy et al. (2025) provide valuable context for this debate but differ from our approach in both scope and identification strategy. Wiser et al. (2025) offer a reduced-form, cross-sectional assessment of state-level electricity price trends, attributing recent variation to multiple factors such as natural-gas exposure, Renewable Portfolio Standards (RPS), extreme-weather costs, and behind-the-meter (BTM) solar growth. O'Shaughnessy et al. (2025), in contrast, focus narrowly on the design of net-metering policies, quantifying the potential rate impacts of rooftop solar for non-adopting households. Together, these studies highlight how distributed generation and policy design can affect retail rates but rely on descriptive or engineering frameworks that do not isolate causal effects across time and jurisdictions. Our analysis tests directly whether these relationships persist once we control for unobserved state-level heterogeneity and common temporal shocks.

To address this question, we construct an econometric analysis that controls for both state-specific characteristics and national time trends, allowing us to test whether the apparent correlation between renewables and rates survives when confounders are taken into account. This is the focus of our study. We find that after accounting for these factors, the evidence does *not* support claims that renewable policies or utility-scale renewables are raising prices. Instead, the remaining signals point toward two underappreciated drivers: rooftop solar—through its effects on tariff design and cost allocation—and climate change, which is already raising system costs through storm and wildfire

[3] See White House Fact Sheet: "Zero-Based Regulation to Unleash American Energy," Apr. 2025.

[4] Time, "Breaking Down All of Trump's Day 1 Presidential Actions," Jan. 21, 2025.

hardening.

While our analysis is not designed to make *definitive* causal claims, it aims to clarify which commonly cited explanations for rising electricity prices are consistent with the data once key confounding factors are addressed. In particular, our empirical framework seeks to rule out certain narratives, such as the claim that renewable policies themselves are driving rate increases, while strengthening the plausibility of other mechanisms, including rooftop-solar cost recovery and climate-driven grid investments. Rooftop solar remains a plausible contributor to higher retail rates through cost-recovery and tariff-design channels, and climate change remains a credible source of upward pressure through its effects on grid hardening, storm recovery, and infrastructure resilience costs. By systematically controlling for both state-specific and national shocks, and by later incorporating state-specific linear trends, we identify which associations persist under increasingly demanding specifications. This approach does not guarantee causality in the experimental sense but helps narrow the set of credible explanations for observed price dynamics and guides future research toward more fully causal designs. On-going work seeks to use additional empirical methods to further establish causality.

2 Data

Our strategy requires data that capture time-series fluctuations in US residential electricity prices, state-level generation mixes, RPS policies, and utility spending behavior. These would enable us to estimate empirical relationships between each category. These are provided publicly by the Lawrence Berkeley National Laboratory (LBNL), the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC).[5]

We source state-level nominal percentages for RPS polices from the LBNL.[6] These are defined as the contemporary percentage of total electricity sales that utilities must or are encouraged to procure from renewable generation. We use these nominal values as measures of RPS policies and control for the heterogeneity associated with the eligibility criteria and state-level implementation using state and year fixed effects (more on this in the Empirical Framework section). The earliest year available for this dataset is 2000, so we restrict our analysis to 1998 to capture trends before widespread RPS adoption in the early 2000s.

[5]Throughout our analysis, we the terms "Solar" and "PV" interchangeably as photovoltaic (PV) panels are the predominant form of solar generation in the US.

[6]LBNL, U.S. State Renewables Portfolio & Clean Electricity Standards: 2024 Status Update, 2024.

The EIA administers the Annual Electric Power Industry Report to participants in the electric power industry such as utility companies and other power distributors. These data include state average residential electricity prices that range from 1960 through 2024 which serve as our outcome variable for subsequent regression analysis.[7] We represent these prices relative to 1998 values and observe in Figure 2 that several states have experienced price increases above the rate of inflation.

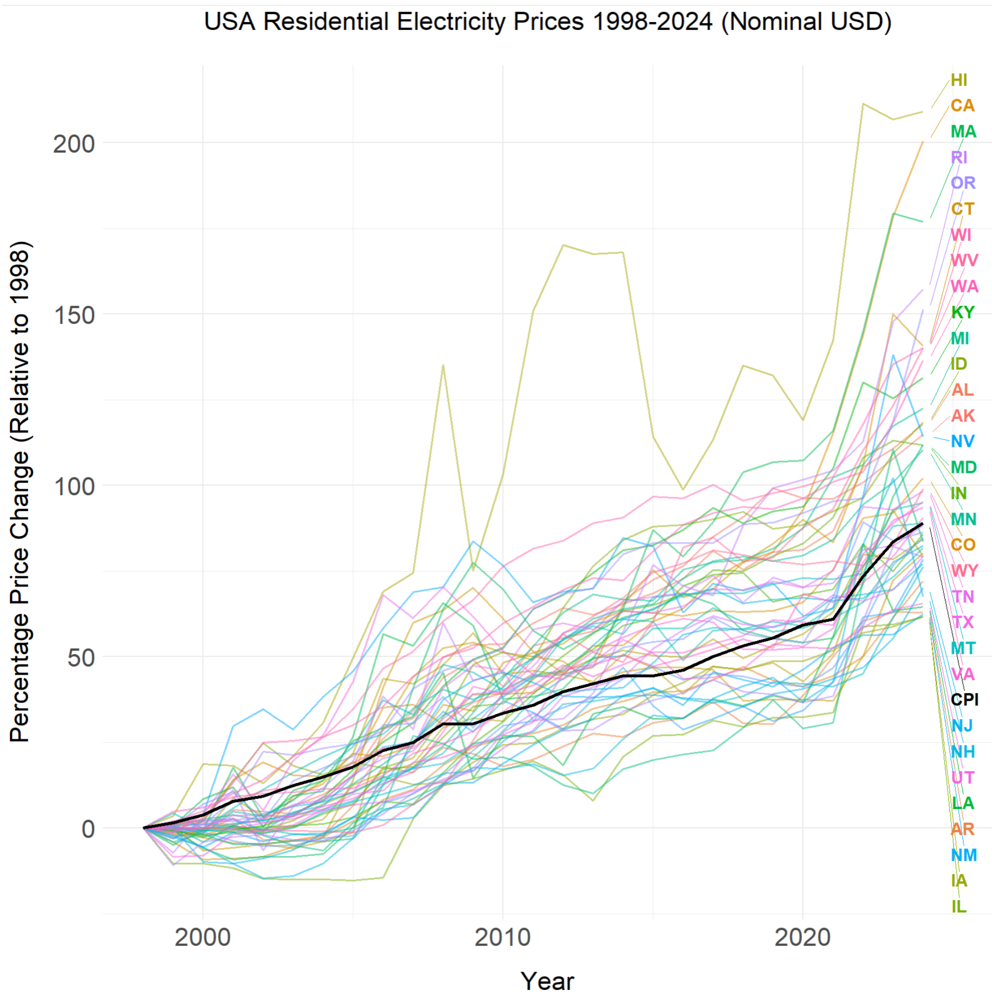


Figure 2: Residential electricity prices for all states in the USA. The solid black line indicates the Consumer Price Index (CPI) to track the rate of inflation. All values are expressed as percentage changes relative to 1998 values. In 2024, exactly 25 states faced average prices that exceeded the CPI.

We then extract data from the EIA's Power Plant Operations Report, which reports state-level information on aggregate utility-scale generation from a variety of technologies.[8] For our analyses, we express the contribution of each source as a share of total generation for each state and year.

[7] EIA, Form 861 - Annual Electric Power Industry Report, Oct. 2025.

[8] EIA, Form 923 - Power Plant Operations Report, Sep. 2025.

Lastly, we retrieve rooftop solar generation from the EIA's State Energy Data System. This data set includes the variable SOR7P which is described as "solar photovoltaic electricity generation by small-scale applications in the residential sector;" we define this as rooftop solar in our analyses and scale it as a share of total generation within each state such that we can compare its contribution with utility-scale resources.[9] At the time of writing, the most recent SEDS release contains data through 2023.

To analyze utility spending behavior, we use data from the FERC's Electric Utility Annual Report (Form-1), a public filing that has been collected annually from more than 200 utilities across the United States since 1981. These filings contain utility-reported disaggregated spending information on several cost categories, including generation, transmission, and distribution, along with total electricity sales by sector.[10] There are well-documented challenges associated with these filings as their procedures are not standardized across all years, and they contain some outlier values. To alleviate these challenges, the Public Utility Data Liberation (PUDL) has published cleaned data sets and guidance on addressing these inconsistencies (Selvans et al., 2025).

We use Python and R-Studio to extract Operation & Maintenance (O&M) costs, Capital Expenditures (CapEx), and electricity sales by sector from both the original Form-1 and PUDL data. The Form-1 data do not map utilities to the states they serve, so we use a crosswalk from the Rocky Mountain Institute's Utility Transition Hub that allows us to associate each utility with each state that it serves.[11] We then evenly distribute each utility's costs and sales across its associated states to avoid double-counting. We next remove the maximum and minimum values from each cost and sales category to reduce the influence of outliers and better represent overall trends. Lastly, we calculate the rate of spending on CapEx and O&M per kWh of electricity sold to ultimate consumers and for resale in each category.

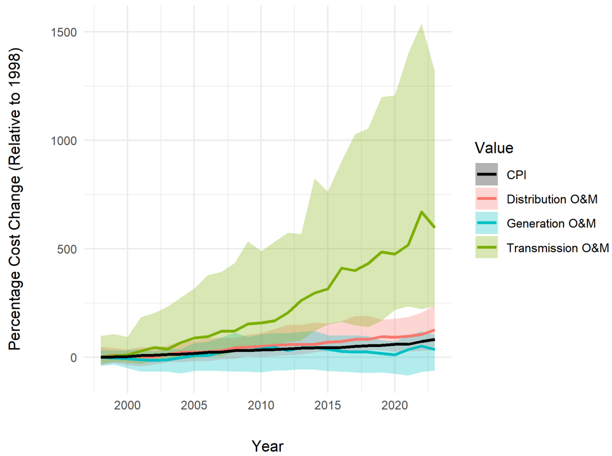
The data show that utilities spend relatively little on O&M, with less than half a cent per kilowatt-hour going toward transmission and distribution (Appendix Figures A3 and A4). This pattern aligns with findings from Fares and King (2017). Because our analysis estimates log-log regression models that focus on relative trends rather than absolute cost magnitudes, our results remain robust even if actual costs are larger than those reported in Form-1, provided actual costs are proportional to those reported in the Form-1 data. Figure 3 plots CapEx and O&M costs per

[9] EIA, State Energy Data System, Jun. 2025.

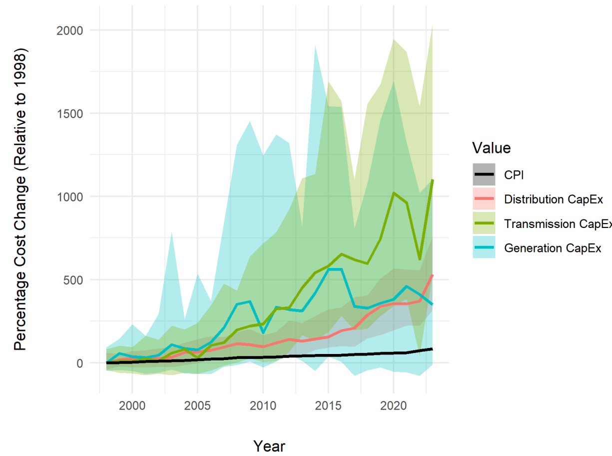
[10] FERC, Form 1 - Electric Utility Annual Report, Oct. 2025.

[11] RMI, Utility State Map - Utility Transition Hub, 2022.

kWh of electricity sold for the past 25 years as reported by utilities in FERC's annual survey. When visualized, we find that utility costs have risen substantially over the observed period, with O&M expenses associated with transmission and distribution outpacing the rate of inflation.



(a) Median and interquartile plot for operation and maintenance expenses



(b) Median and interquartile plot for capital expenditure investments

Figure 3: These plots visualize the median and interquartile values for each of the transmission, distribution, and generation costs for both O&M and CapEx spending categories. All costs are expressed as percentage changes relative to 1998. The solid lines indicate medians in the data. The top and bottom color ranges indicate the upper 75th and lower 25th percentile ranges, respectively. Disaggregated plots for each cost category are in Appendix Figures A2 and A3.

Our final data set consists of residential electricity prices, energy generation mixes that include rooftop solar (all in shares), and utility spending information (CapEx and O&M) on generation, transmission, and distribution per kWh of total electricity sold. Based on the available years of data, we focus our analysis on the years 1998 - 2023 to adequately capture contemporary trends and concentrate on periods with high rates of renewable penetration.

3 Empirical Framework

Our empirical strategy uses an observational design intended to approximate an experimental counterfactual. We compare changes in electricity rates within states over time, rather than differences across states, controlling for unobserved heterogeneity and common shocks. Specifically, we estimate models of the form

$$\text{Rate}_{st} \;=\; \beta_1\,\text{RPS}_{st} \;+\; \beta_2\,\text{Renewables}_{st} \;+\; \gamma_s \;+\; \delta_t \;+\; \mathbf{X}'_{st}\theta \;+\; \varepsilon_{st}, \tag{1}$$

where γ_s represents state fixed effects that capture persistent, time-invariant state characteristics (e.g., regulatory environment, climate, generation mix), and δ_t represents year fixed effects that capture national trends such as macroeconomic cycles or fuel prices. The vector $\mathbf{X}_{st}$ includes additional controls (e.g., demand/weather proxies, generation shares, fuel costs). The key parameters β_1 and β_2 measure whether, after removing these effects, changes in RPS stringency or renewable generation remain correlated with changes in electricity rates.

If the relationship between renewables and prices disappears once these fixed effects are introduced, the correlation likely reflects omitted factors rather than causal effects. If it persists, renewables may play a more direct causal role. Although this is not a randomized trial, the approach leverages standard causal-inference logic to "control for confounders" and focus on within-state, over-time variation.

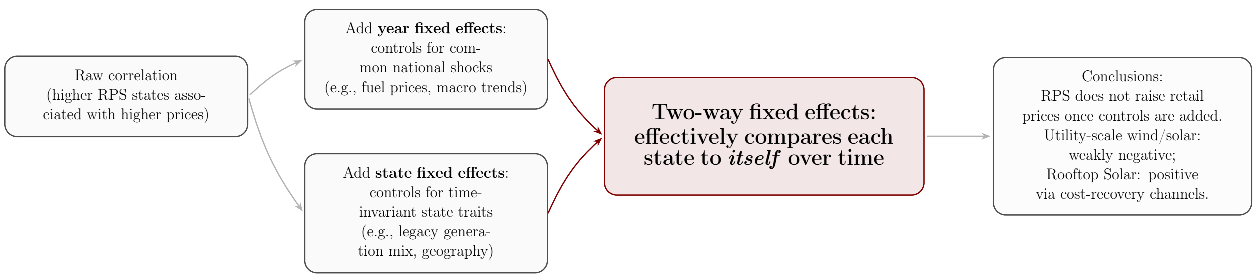


Figure 4: From raw correlation, add year and state fixed effects separately, then combine both in a two-way fixed-effects model to form conclusions.

4 Results

4.1 Renewable Portfolio Standards

We first examine the role of Renewable Portfolio Standards. Without controls, states with more stringent RPSs exhibit higher electricity prices. Introducing year fixed effects reduces the relationship, suggesting that national time trends—such as fuel price cycles—explain part of the correlation. Adding state fixed effects alone does not materially change the result, but once both sets of controls are included, the relationship between RPS stringency and retail prices disappears entirely.

Interpretation: once we compare each state to itself over time, the apparent connection between renewable mandates and price increases vanishes as seen in Figure 5. Higher-price states have adopted stronger RPSs, but RPS adoption does not *cause* higher prices

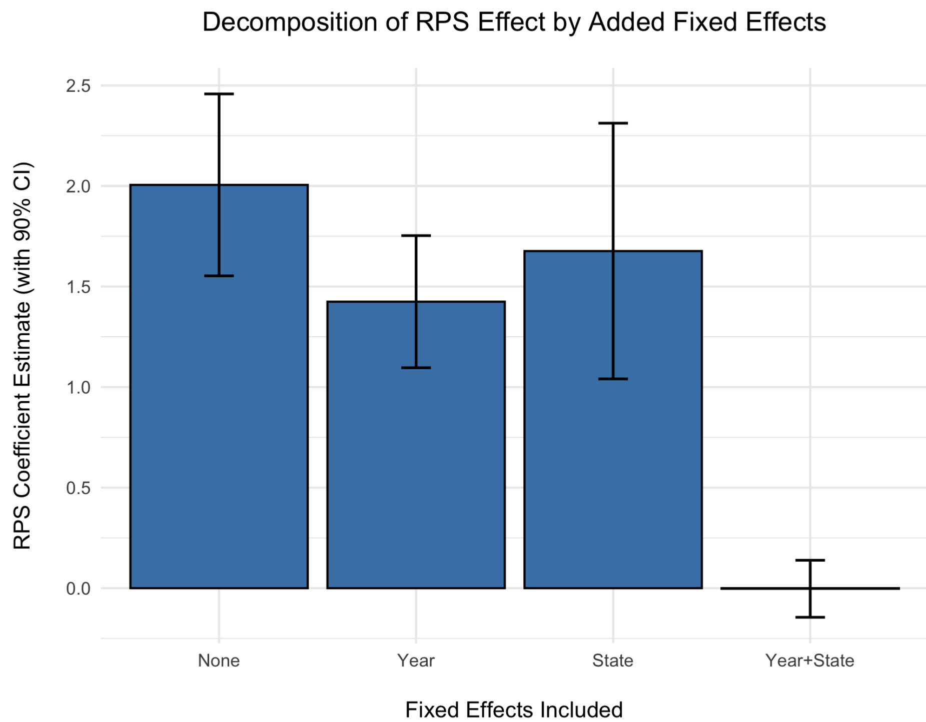


Figure 5: Decomposition of RPS effect with added fixed effects (Appendix Table A1). The blue bars indicate the coefficient's value, and the whiskers indicate a 90% confidence interval. The dependent variable is the log of nominal residential electricity prices, and the regressor is the state-year RPS as a share of total utility sales. Without fixed effects, the RPS appears to have a strong positive correlation. Independently adding individual year and fixed effects and state fixed effects reduces the correlation. However, adding both state and year fixed effects nullifies the effect to approximately zero, which indicates that these correlations are not causal.

4.2 Utility-Scale Renewables and Rooftop Solar

We next evaluate the generation mix. We include the generation share of each technology as control variables.[12] The magnitude of the RPS coefficient falls by nearly 80% once we control for state fixed effects. This suggests that high-price states have been more likely to adopt RPSs. After controlling for state and year effects in Figure 6, utility-scale solar and wind generation are *negatively* correlated with electricity prices, with utility-scale solar being marginally statistically significant. Natural gas generation also exhibits a negative (marginally significant) association. In contrast, rooftop photovoltaic (PV) penetration remains *positively* correlated with rates and also marginally significant, consistent with its impact on cost allocation and tariff structure.[13]

[12]Because the shares add up to one, one technology must be omitted; we omit coal. Therefore, the estimates should be interpreted as the impact of a given share on retail prices *relative* to coal generation.

[13]When we include Hawaii and Alaska and extend the sample to 1990, the coefficient on rooftop solar is significant at the 0.01 level.

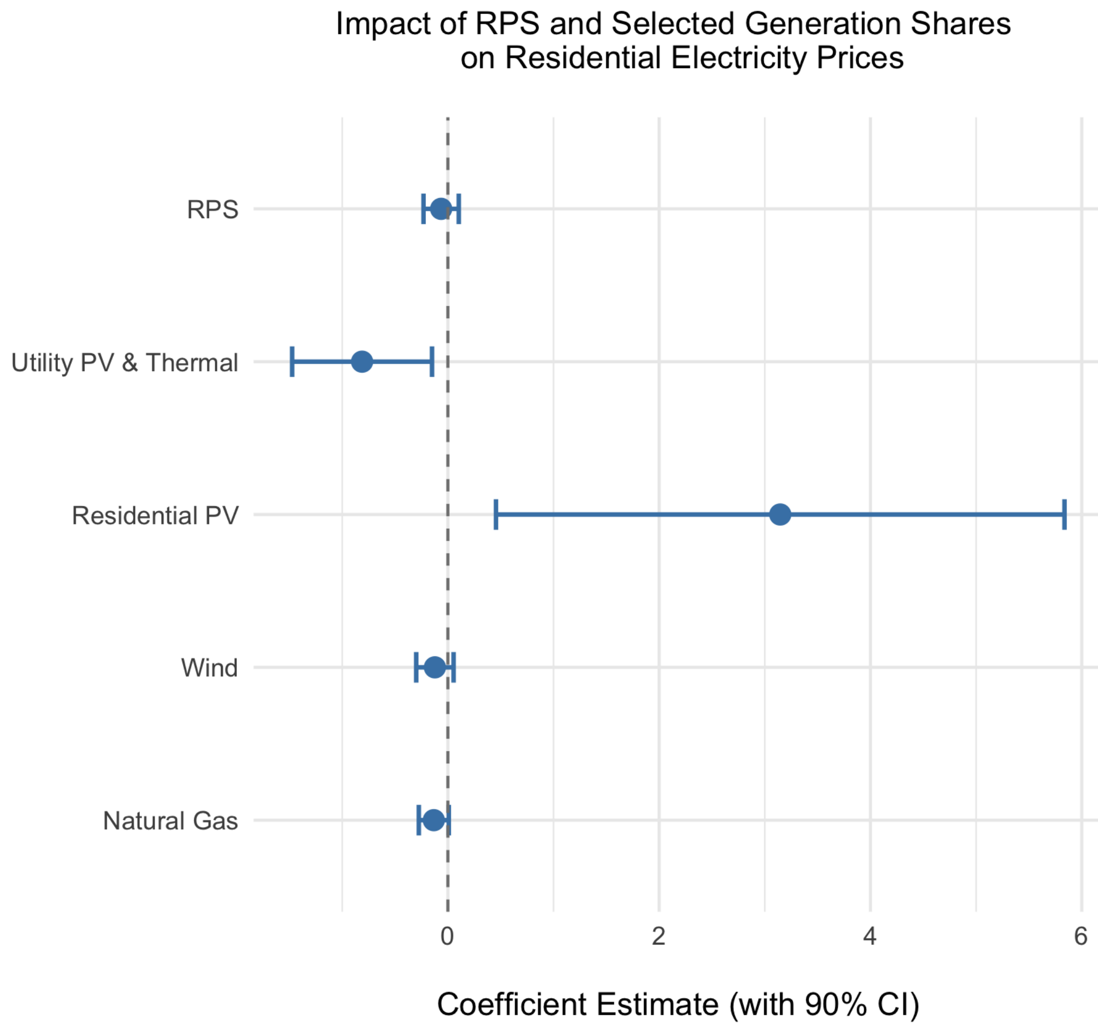
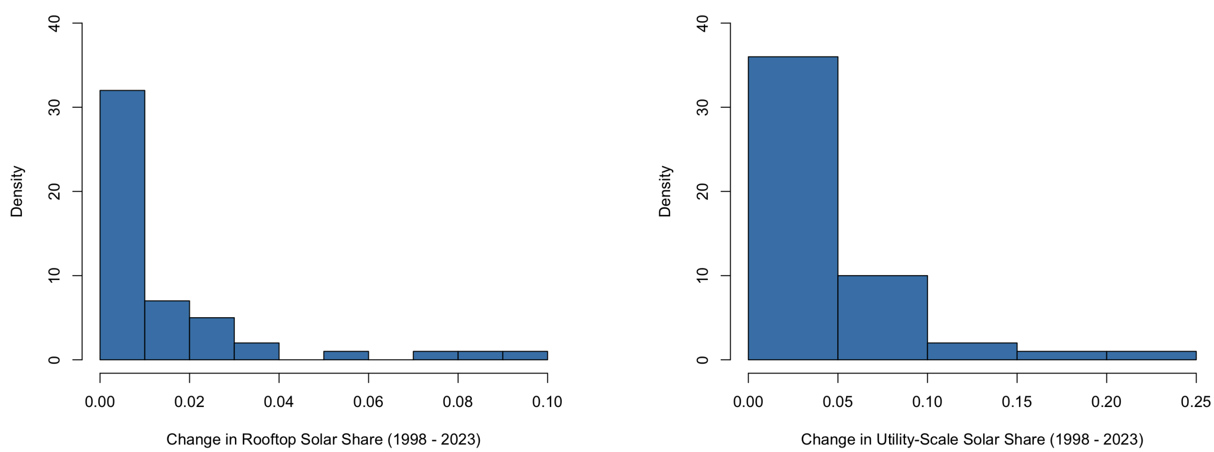


Figure 6: Coefficient plot of two-way fixed effects regression on RPS and generation shares by technology type of total generation. The blue dots indicate the coefficient's value, and the whiskers indicate a 90% confidence interval. The full regression is included as Appendix Table A2, and an additional plot visualizing all coefficient impacts is included as Appendix Figure A1. These results indicate that higher generation shares of Utility-Scale PV correlate with lower residential electricity prices, whereas higher shares of Residential PV correlate with higher prices.

The change in rooftop solar penetration varies widely across states but is generally modest. Panel (a) of Figure 7 shows that over half of all state-year observations exhibit increases of less than two percentage points. Only four states—California, Hawaii, Massachusetts, and Vermont—saw increases exceeding five percentage points. Using our estimated coefficient of 3.15, a five-percentage-point rise in rooftop solar share corresponds to an increase in average residential electricity prices of roughly 16 percent ($\$3.15 \times 0.05$). In other words, while most states experience changes too small to materially affect rates, the handful of high-adoption states experience sizable upward pressure on prices consistent with the magnitude of the estimated rooftop-solar effect.

Utility-scale solar expansion has also been highly uneven across states. As shown in panel (b) of Figure 7, most states experienced only modest growth in utility-scale solar generation—typically under five percentage points over the sample period—while a few saw much larger increases. Four states, led by California, Nevada, Massachusetts, and Utah, recorded increases exceeding ten percentage points. Given the estimated coefficient of roughly −0.81 for utility-scale solar, a ten-percentage-point rise in the share of generation from this source implies a decline in residential electricity prices of just over eight percent. Thus, while most states experience small or negligible effects, the handful with rapid utility-scale solar growth see meaningful downward pressure on prices, consistent with declining marginal generation costs and economies of scale in large-scale solar deployment.



(a) Histogram of state-level rooftop solar share changes

(b) Histogram of state-level utility-scale solar share changes

Figure 7: Distributions of state-level changes in solar generation shares over the sample period. Panel (a) shows rooftop solar: most states experienced small increases (often under two percentage points), with a thin upper tail in which four states—California, Hawaii, Massachusetts, and Vermont—exceeded five percentage points. Panel (b) shows utility-scale solar: most states saw increases under five percentage points, while California, Nevada, Massachusetts, and Utah exceeded 10 percentage points. These skewed distributions motivate the magnitude calculations discussed in the text.

Our estimates imply that Renewable Portfolio Standards operate primarily by changing the generation mix: they induce additional utility-scale wind and solar, which we find to be weakly associated with *lower* retail prices, and they are also correlated with greater rooftop solar adoption, which is associated with *higher* prices through tariff and cost-recovery channels. When we include technology shares in the regression, we are conditioning on variables that are themselves downstream of RPS. As a result, the RPS coefficient in these specifications should be interpreted as a *direct* effect holding the induced mix fixed, rather than a *total* (reduced-form) effect of the policy. This helps reconcile the patterns in our results: the opposing signs of the induced technologies can offset one another, so the total effect of RPS on prices appears close to zero in reduced-form models, and the direct effect of RPS becomes statistically indistinguishable from zero once we condition on the mix. In short, the "zero" on RPS is consistent with RPS causing both price-decreasing utility-scale renewables and price-increasing rooftop solar, whose net effects largely cancel in the aggregate.

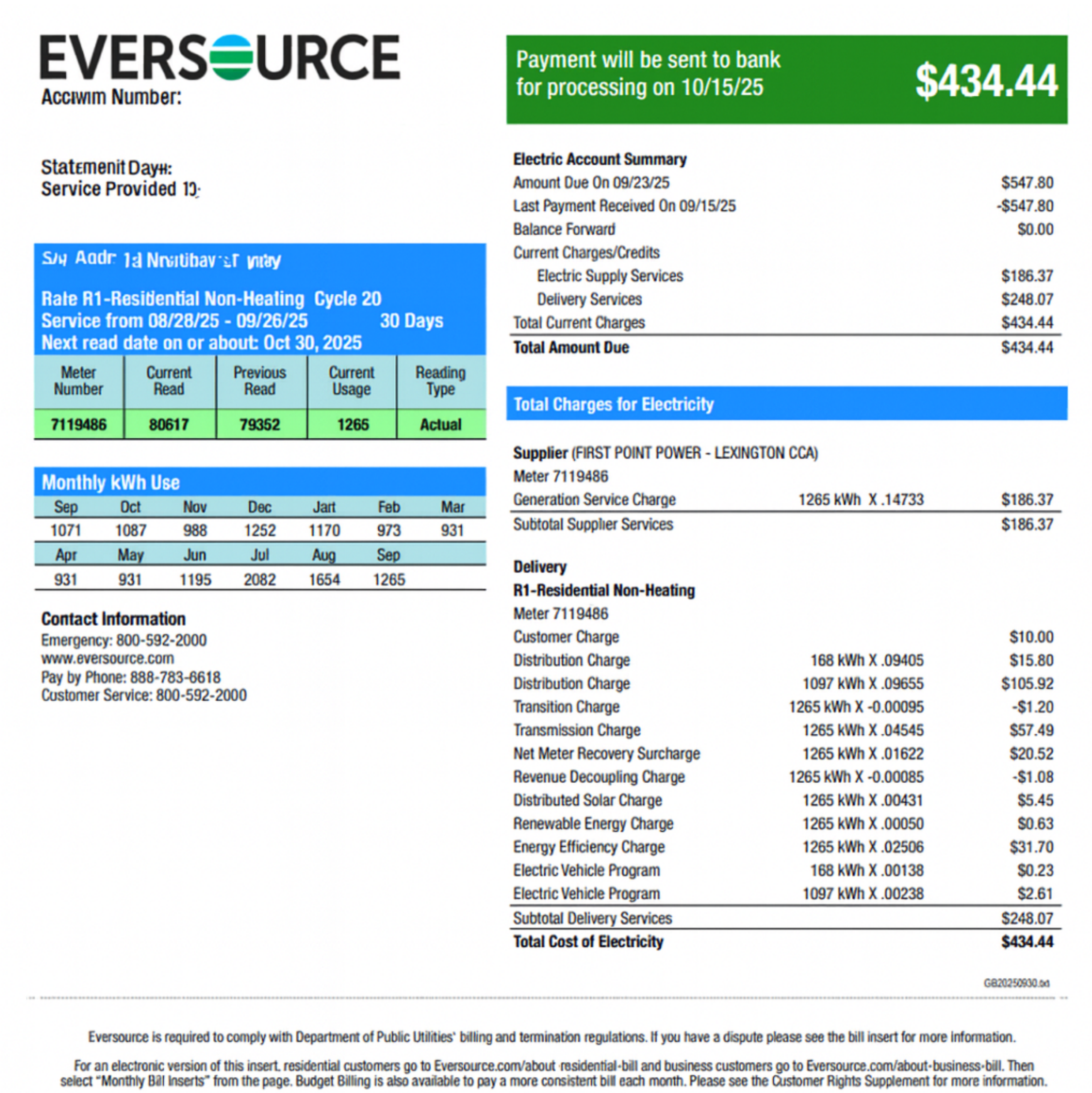
What are the potential mechanisms through which rooftop solar raises rates? Rooftop solar affects bills through several channels. Because most states retain some form of net metering or bill-crediting structure, households with rooftop solar often pay reduced distribution and transmission charges. These fixed costs are then shifted to remaining customers through higher per-kWh charges. Moreover, many states impose "policy riders"—charges funding electric-vehicle infrastructure, efficiency programs, and distributed-solar incentives—that collectively account for up to 15% of total rates in some jurisdictions.

A concrete illustration from a Massachusetts bill. A typical Eversource residential bill helps illustrate how the largely fixed costs of transmission and distribution are recovered. Figure 8 is a recent bill from one of the authors. The bill separates the *supply* component (energy only) from the *delivery* component, which includes network and policy charges. In this September 2025 statement for a Lexington, MA customer, the supply charge is \$186.37, while delivery charges total \$248.07, yielding a bill of \$434.44. In other words, more than half of the total amount due reflects delivery and policy costs rather than the electricity itself. These transmission and distribution costs are mostly fixed in the short run—they depend on the size and reliability of the system, not on how many kilowatt hours a household uses—but they are recovered almost entirely through per-kWh volumetric rates. As more households install rooftop solar and offset a large share of their consumption, they pay less toward maintaining the grid, even though they still rely on it for backup power, evening use, and the ability to export power when their panels are producing more than the household is consuming. This cost-recovery mismatch creates upward pressure on per-kWh charges for everyone else. In addition, because distribution systems were originally designed for one-way power flows—from centralized generators to customers—but the rapid expansion of rooftop solar now requires utilities to accommodate two-way flows. As a result, utilities are investing in new distribution transformers, voltage regulators, and control systems to maintain reliability and power quality as distributed generation penetrates further (Horowitz et al., 2018; Breger et al., 2024).

This cost under-recovery leads utilities and regulators to attempt to fill this recovery gap through a growing set of separate riders and policy line items. The same Eversource bill includes a *Net Meter Recovery Surcharge* of $20.52, a *Distributed Solar Charge* of $5.45, and an *Energy Efficiency Charge* of $31.70. Together, these three items account for about $57.67, or roughly 13% of the total bill. Each of these riders is designed to spread the cost of policy programs or unrecovered distribution expenses across all customers, effectively compensating the utility for revenue lost from customers with rooftop systems. This pattern is consistent with our empirical results: once we control for state and year effects, utility-scale renewables are not associated with higher prices, but rooftop solar penetration remains positively correlated with rates because it alters how fixed grid costs are recovered and requires the addition of new policy surcharges to balance utility finances.

Figure 9 is a recent bill of one of the authors for a cabin in New Hampshire with a solar system. It stands in stark contrast to the Eversource bill. The New Hampshire Electric Cooperative (NHEC) bill lists no explicit policy surcharges or riders as separate line items; any such costs are embedded in base delivery charges. In addition, NHEC uses *net billing* rather than net metering: exported rooftop-PV kilowatt-hours are credited at a rate below the retail price for imports, so a kilowatt-hour sent to the grid is worth less than a kilowatt-hour taken from it. Finally, the monthly customer/connection charge is substantially higher than on the Eversource bill. Together, these features shift more cost recovery to fixed charges, reduce the scope for cost shifting from distributed generation, and dampen bill savings for rooftop-PV customers relative to net-metered tariffs.

These two bills underscore that financing climate and energy-transition costs through electricity rates is a policy choice, not an inevitability. Regulators and legislators have opted to recover many public-purpose expenditures—such as renewable incentives, energy-efficiency programs, and grid-hardening investments—through volumetric electricity charges rather than through the broader tax base. This approach makes the costs of climate and clean-energy policy highly salient to ratepayers but can also make them more regressive, since electricity consumption does not scale proportionally with income. Policymakers could instead choose to fund these programs through general revenues, carbon tax proceeds, or dedicated public funds, thereby spreading costs more equitably across households and sectors. The distinction matters: even when overall system costs are falling due to cheaper renewable generation, using retail rates as the vehicle for cost recovery can still raise bills for many customers. Our results, therefore, speak not only to the cost of renewables themselves but also to the institutional design of how those costs are collected and distributed.



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Rate R1-Residential Non-Heating Cycle 20
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Meter Number	Current Read	Previous Read	Current Usage	Reading Type
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Monthly kWh Use

Sep	Oct	Nov	Dec	Jan	Feb	Mar
1071	1087	988	1252	1170	973	931
Apr	May	Jun	Jul	Aug	Sep	
931	931	1195	2082	1654	1265	

Contact Information
Emergency: 800-592-2000
www.eversource.com
Pay by Phone: 888-783-6618
Customer Service: 800-592-2000

Electric Account Summary

Amount Due On 09/23/25	$547.80
Last Payment Received On 09/15/25	-$547.80
Balance Forward	$0.00
Current Charges/Credits	
Electric Supply Services	$186.37
Delivery Services	$248.07
Total Current Charges	$434.44
Total Amount Due	**$434.44**

Total Charges for Electricity

Supplier (FIRST POINT POWER - LEXINGTON CCA)		
Meter 7119486		
Generation Service Charge	1265 kWh X .14733	$186.37
Subtotal Supplier Services		$186.37
Delivery		
R1-Residential Non-Heating		
Meter 7119486		
Customer Charge		$10.00
Distribution Charge	168 kWh X .09405	$15.80
Distribution Charge	1097 kWh X .09655	$105.92
Transition Charge	1265 kWh X -0.00095	-$1.20
Transmission Charge	1265 kWh X .04545	$57.49
Net Meter Recovery Surcharge	1265 kWh X .01622	$20.52
Revenue Decoupling Charge	1265 kWh X -0.00085	-$1.08
Distributed Solar Charge	1265 kWh X .00431	$5.45
Renewable Energy Charge	1265 kWh X .00050	$0.63
Energy Efficiency Charge	1265 kWh X .02506	$31.70
Electric Vehicle Program	168 kWh X .00138	$0.23
Electric Vehicle Program	1097 kWh X .00238	$2.61
Subtotal Delivery Services		$248.07
Total Cost of Electricity		**$434.44**

GB20250930.txt

Eversource is required to comply with Department of Public Utilities' billing and termination regulations. If you have a dispute please see the bill insert for more information.

For an electronic version of this insert, residential customers go to Eversource.com/about residential-bill and business customers go to Eversource.com/about-business-bill. Then select "Monthly Bill Inserts" from the page. Budget Billing is also available to pay a more consistent bill each month. Please see the Customer Rights Supplement for more information.

Figure 8: Illustrative Eversource residential bill (Lexington, MA; September 2025) separating the *supply* (energy) and *delivery* (network and policy) components. Delivery charges ($248.07) exceed the supply charge ($186.37), highlighting that more than half of the total bill ($434.44) reflects fixed transmission, distribution, and policy-riders costs. Line items such as the Net Meter Recovery Surcharge, Distributed Solar Charge, and Energy Efficiency Charge illustrate how cost recovery is implemented through the delivery component.

nhec.com | 1-800-698-2007

Account Number: **Type of Service: Residential** **Next Scheduled Read Date: 11/01/2025**

Rate	Meter #	Service Period	Start Reading	End Reading	Meter Multiplier	kWh Usage	Demand	Comment
N01A	901887	09/01/2025 - 10/01/2025	1419	1524	1	105		
N02A	901887	09/01/2025 - 10/01/2025	3924	4647	1	723		
PVN	901562	09/01/2025 - 10/01/2025	4733	5559	1	826	5.78	

NHEC Electric Charges

Member Service Charge		$34.66
Delivery Charge	105 kWh x 0.04689	$4.92
Delivery Charge Export	723 kWh x -0.02482	-$17.94
System Benefit Charge	105 kWh x 0.00756	$0.80
System Benefit Export	723 kWh x -0.00756	-$5.46
Regional Access Charge	105 kWh x 0.03894	$4.09
Regional Access Export	723 kWh x -0.00582	-$4.21
Co-op Power Charge	105 kWh x 0.11464	$12.04
Co-op Power Charge	723 kWh x -0.09253	-$66.90
Current NHEC Electric Charges		**-$38.00**

Summary of Charges

Other Charges/Credits		
Monitor Pv	$3.00	
Subtotal		**$3.00**
Current NHEC Electric Charges	-$38.00	
Subtotal		**-$38.00**
Balance Forward		**-$92.32**
Total Balance Due		**-$127.32**

Power Supplied By: **NHEC**

Figure 9: Illustrative New Hampshire Electric Cooperative residential bill (Freedom, NH; September 2025). Unlike Eversource, there are no policy-rider line items; rooftop-PV exports are credited at a net-billing rate below the retail import price (no net metering), and the fixed customer/connection charge is materially higher.

4.3 Impact on Utility Operation & Maintenance Costs

Based on previous results and the bill examples, we extend our analysis to understand a potential channel through which utility-scale renewables and rooftop solar may impact electricity prices: delivery O&M costs. Renewables have relatively low O&M costs as they do not require fuel inputs. This creates a downward pressure on total system costs when renewables are located on the transmission network, which accommodates bi-directional power flows. Because of this, we would expect states with greater utility-scale renewable generation shares to have lower generation O&M costs. The impact on transmission and distribution O&M is less clear. Because large solar facilities are often sited near substations or major load centers, they may shorten the physical distance between generation and demand, lowering both power losses and the need for long-distance transmission capacity. Their daytime generation profile also coincides with peak demand periods, especially in hot, air-conditioning-intensive regions, thereby relieving congestion and thermal stress on transmission lines when they would otherwise be most heavily loaded. On the distribution side, by meeting part of the load at the transmission or sub-transmission level, these facilities reduce the volume of power that must flow through local feeders and transformers, easing thermal and voltage stress on the distribution network. In regions where daytime demand peaks are partially offset by solar generation, the resulting flattening of the diurnal load curve reduces the need for distribution upgrades sized for infrequent peak loads. Utilities may also locate utility-scale solar projects near substations or congested feeders, where they can provide voltage support and reactive power services that enhance reliability and reduce wear on equipment. Finally, because developers often bear a share of interconnection and infrastructure upgrade costs, utility accounting practices may further reinforce the observed decline in reported distribution O&M and capital expenditures.

Rooftop solar, however, diverges from this because these systems are often located on the distribution side of the grid, where power flows are more complex and costly to manage. When households generate their own electricity, they reduce the amount of energy purchased from the grid but still depend on it for backup, nighttime supply, and power exports during the day. This intermittent, bidirectional flow of electricity requires additional voltage regulation, protection coordination, and metering infrastructure, raising distribution O&M costs. As more customers adopt rooftop systems, utilities must invest in stronger feeders, upgraded transformers, and advanced control equipment to accommodate reverse power flows and maintain reliability. At the same time, because many fixed grid costs are recovered through per-kilowatt-hour volumetric rates, declining sales to solar customers leave utilities with less revenue to cover transmission and distribution expenses. These costs are then spread across a smaller sales base, driving up reported delivery costs and average retail rates. The combination of higher technical requirements and revenue-recovery pressures helps explain why states with higher rooftop solar penetration exhibit rising grid O&M and capital expenditures.

We validate this by estimating the impact of state-level generation shares on utility-level O&M costs per kilowatt-hour of electricity sold using a regression model with state, year, and utility fixed effects. We report our key results in Figure 10 with 90% confidence intervals. A higher share of rooftop solar is associated with *increased* distribution and total O&M costs. In contrast, utility-scale solar and wind are correlated with *lower* distribution and total O&M costs. Additionally, utility-scale solar is correlated with *lower* transmission O&M costs.

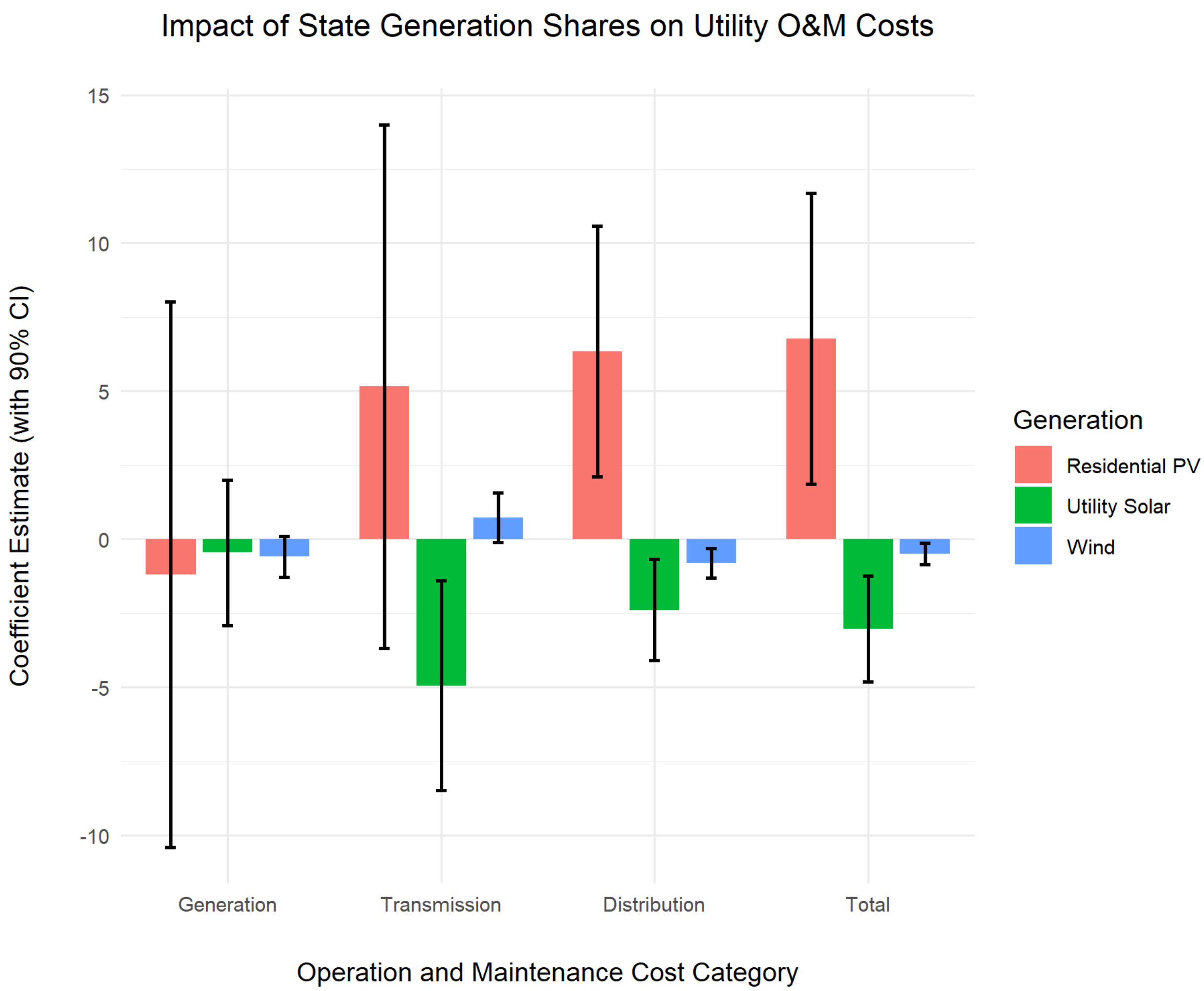


Figure 10: Plot displays coefficient estimates for three separate regressions. The impact of generation shares on the O&M cost category is estimated for transmission in Appendix Table A6, distribution in Appendix Table A5, generation in Appendix Table A7, and combined costs in Appendix Table A9. All regressions displayed include three-way fixed effects for state, year, and utility. Residential PV is consistently correlated with higher distribution and total costs for utilities whereas utility-scale solar and wind are associated with lower delivery and total costs.

We next consider potential effects on capital expenditures across different technologies. The patterns we observe in O&M costs are mirrored, to some extent, in CapEx. Utility-scale solar generally places downward pressure on generation and delivery capital costs. By substituting for new fossil plants—which are typically more capital-intensive per unit of capacity—utility-scale projects allow utilities to meet resource needs with lower overall capital outlay. Because these facilities are often sited near existing substations or within load pockets, they can also defer or reduce the need for new transmission and distribution investments. When projects are located in remote, high-resource regions, they may temporarily raise transmission CapEx through new interconnection or line extensions, but these costs are often offset by the avoided or delayed construction of long-distance infrastructure elsewhere. Overall, utility-scale solar can reduce both generation and grid-related capital intensity by localizing supply and aligning output with peak demand periods.

Rooftop solar, by contrast, has a more nuanced relationship with capital requirements, particularly on the distribution side. Previous research has found that increased rooftop solar penetration reduces strain on the distribution grid by enabling more households to self-consume during peak hours; as a result, utilities can defer capital upgrades in feeders, transformers, and voltage-regulation equipment (Cohen et al., 2016). This logic underlies the NEM 3.0 tariff structure in California where the compensation for exported energy is determined by the Public Utility Commission's Avoided Cost Calculator. The current methodology calculates the value of exported rooftop solar (and storage) as a function of deferred or avoided investments in distribution, transmission, and generation capacity infrastructure, among other benefits such as avoided emissions (Energy and Environmental Economics, 2024). While this may hold true in some scenarios, our analysis on national trends shows that rooftop solar has an insignificant, near-zero effect on distribution CapEx. We instead find that rooftop solar is correlated with higher distribution O&M costs. A potential explanation is that deferring investment in distribution networks while offering incentives for rooftop solar exports forces utilities to manage the physical and administrative complexity of harmonizing small, decentralized generators with antiquated infrastructure. Ultimately, while rooftop solar may reduce capital costs, it may still place additional strain on the grid by increasing bidirectional power flows which may have implications for the design of net billing policies.

For wind generation, the relationship with CapEx is more mixed. Wind farms are among the most capital-intensive generation sources to build, requiring substantial upfront investment in turbines and foundations, often located in remote regions far from demand centers. This geographic pattern frequently necessitates new high-voltage transmission lines to transport power to load, raising transmission CapEx in the short to medium term. However, once integrated, wind's low variable costs and absence of fuel inputs can reduce the need for new thermal generation capacity, lowering long-run generation CapEx. Thus, while wind deployment can initially raise investment requirements in transmission and generation infrastructure, it ultimately contributes to a more capital-efficient and resilient system once those fixed investments are in place.

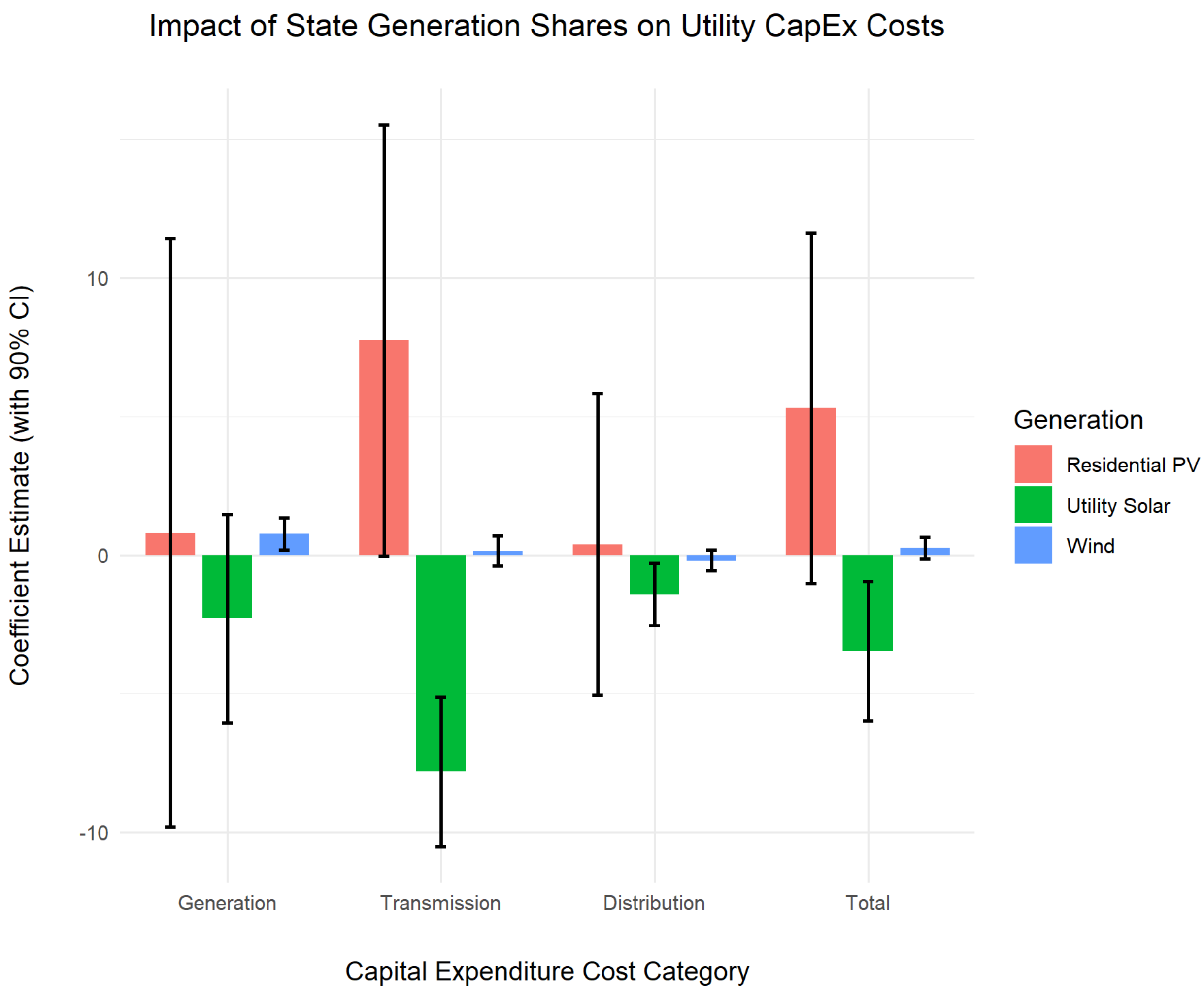


Figure 11: Plot displays coefficient estimates for three separate regressions. The impact of generation shares on the CapEx cost category is estimated for transmission in Appendix Table A11, distribution in Appendix Table A10, generation in Appendix Table A12, and combined costs in Appendix Table A14. All regressions displayed include three-way fixed effects for state, year, and utility. Utility-scale solar is consistently correlated with lower transmission and distribution CapEx requirements. Wind follows a similar, though much weaker, trend and rooftop solar generally correlates with higher CapEx requirements.

4.4 Threats to Identification of Causal Relationships

While our two-way fixed effects framework provides strong suggestive evidence of a causal relationship between renewable policies, generation mix, and electricity prices, causality is not guaranteed. The design removes many sources of spurious correlation by comparing each state to itself over time and netting out common national shocks, but residual endogeneity and omitted-variable concerns may still bias the estimated coefficients. Several threats to identification remain.

First, policy endogeneity is a central concern. Renewable Portfolio Standards (RPSs) and distributed-solar programs are rarely implemented at random. States may adjust these policies in anticipation of future market conditions or infrastructure needs. For example, states expecting higher future prices or reliability challenges might strengthen renewable mandates as a preemptive hedge, creating an upward bias if the timing of policy adoption coincides with other cost drivers. Similarly, political or economic cycles correlated with electricity prices could jointly influence both renewable adoption and rate design. In some ways, this strengthens the conclusion that RPSs are leading to higher rates since the RPS coefficient would be biased upward, making us more likely to find a positive association.

Second, unobserved time-varying confounders may persist even after controlling for state- and year-fixed effects. Factors such as aging generation infrastructure, regional transmission investments, and evolving utility regulatory frameworks vary across states and over time in ways that may correlate with both renewables and rates. Although our inclusion of fuel-mix variables and natural-gas shares captures some of these dynamics, other evolving cost drivers, such as wildfire mitigation, storm hardening, or shifts in wholesale market design, may still bias coefficients if unaccounted for.

Third, reverse causality remains plausible. Higher retail prices can encourage rooftop-solar adoption, as households seek to offset utility bills, or motivate policymakers to accelerate renewable deployment. If price increases partially cause renewable growth rather than the reverse, our estimates may overstate the causal impact of rooftop solar on rates. Because we are including fixed state effects, higher rate *levels* would not be a threat to identification, but high *growth* rates might be. To probe the robustness of these results, we estimate a specification in Appendix Table A2 that introduces state-specific linear and quadratic time trends, allowing each state to follow its own secular trajectory in electricity prices. These additions absorb any slow-moving, unobserved determinants of rates, such as gradual shifts in demographics, infrastructure age, or regulatory stringency, that could confound the relationship between renewables and prices.

Under this more demanding specification, the rooftop-solar coefficient remains positive and becomes larger in magnitude and statistically significant (approximately 8.0167, $p = 0.01$, see A2). The persistence and strengthening of this estimate after controlling for state trends suggest that the rooftop-solar effect is unlikely to be driven solely by long-term structural differences across states. Instead, it points toward a genuine within-state mechanism consistent with the cost-recovery and tariff-design channels discussed earlier.

By contrast, the RPS coefficient remains statistically indistinguishable from zero even with linear and quadratic trends, reinforcing the conclusion that renewable mandates themselves are not causally increasing rates.

4.4.1 Future Research and Strengthening Identification

Future work will deepen this analysis by employing causal identification strategies that move beyond within-state comparisons. The following approaches are particularly promising.

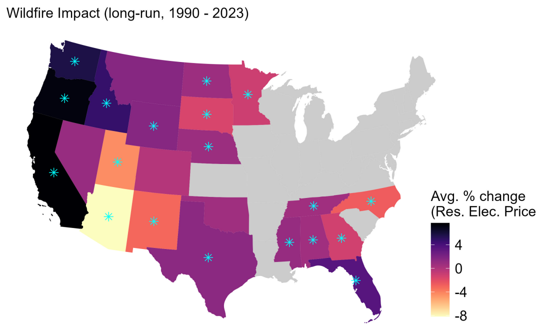
First, instrumental variables (IV) approaches can exploit exogenous variation in renewable potential, such as wind speed or solar insolation, or federal policy shocks, such as tax credit eligibility and regional transmission constraints, as instruments for renewable deployment. These strategies could isolate causal impacts independent of endogenous policy adoption. Second, event-study and staggered-adoption designs can exploit the timing of RPSs and rooftop-solar incentives to test for pre-trends and dynamic effects, strengthening causal interpretation. Such designs can verify that electricity prices were not trending differently prior to policy enactment.

Together, these strategies will allow future research to disentangle policy-induced cost changes from endogenous adoption, yielding sharper causal inference on how renewable policies, generation technologies, and rate design jointly shape electricity affordability.

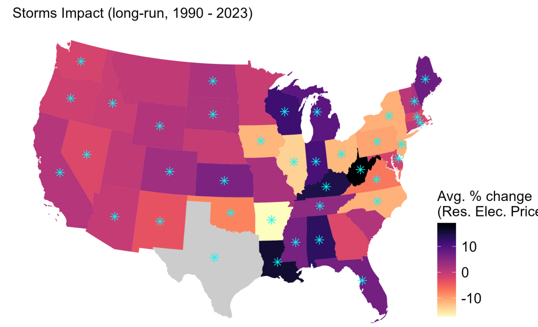
5 Climate Change and Data Centers as Cost Drivers

While debates over renewables dominate the headlines, another force is quietly raising costs: climate change. Utilities are investing heavily to harden systems against increasingly frequent storms and wildfires. These expenditures—covered conductors, vegetation management, fire detection systems, and undergrounding—appear directly in rate cases. In our ongoing work with the Brookings Institution and in peer-reviewed research published in *Science Advances*, we find that climate-related grid costs are already measurably affecting retail rates and exacerbating regional disparities in energy affordability as seen in Figure 12.[14]

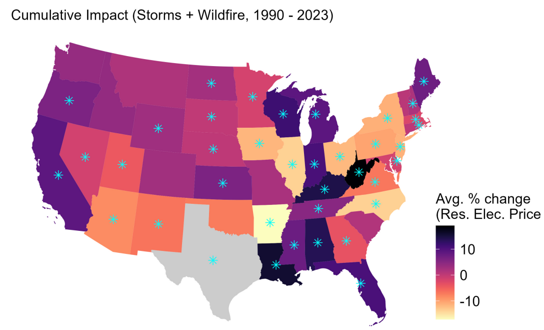
[14] See, Clausing et al. (2025) and Batlle et al. (2024).



(a) Wildfire Impact



(b) Storms Impact



(c) Cumulative Effect

Figure 12: Impacts of climate-enhanced wildfires, storms, and their cumulative effect on residential electricity prices in the contiguous USA. These charts were generated using an interaction effects regression strategy with two-way fixed effects in which the estimated damage caused by wildfires and storms in each particular state were interacted with state fixed effects to explain changes in residential electricity prices. The blue stars on many of the states indicate statistically significant coefficients where $p < 0.10$.

Climate-driven changes in demand compound the problem. Rising cooling degree days increase summer peak loads, prompting capacity investments that further raise fixed costs. In parallel, wildfire risk in the West and storm intensity in the East have prompted utilities to expand their capital-expenditure plans. Even as federal programs such as GRIP and 40101(d) offset some of these investments, much of the cost is ultimately recovered from ratepayers.

Another emerging contributor is the rapid growth of large-scale data centers. These facilities, essential to AI computing, cloud storage, and digital services, are reshaping local electricity demand and grid planning across multiple states. Clusters of new data centers can require hundreds of megawatts of additional capacity, stressing both transmission infrastructure and wholesale market dynamics. The magnitude and regional concentration of this load growth mean that data centers are increasingly relevant to retail price trends. Understanding the interaction between data center expansion, system costs, and rate design is a central topic of ongoing research at MIT's Center for Energy and Environmental Policy Research (CEEPR). Recent work has found that the way in which these data centers are integrated has significant implications for grid-wide costs. When data centers are integrated as flexible loads, they can source their energy more consistently from cost-competitive renewable energy resources, reducing total system costs and emissions (Knittel et al., 2025).

6 Policy Implications and Conclusions

Our analysis allows us to rule out some common suspects. Renewable Portfolio Standards and utility-scale solar and wind are *not* responsible for recent retail rate increases once confounding factors are controlled. These findings challenge the narrative that "green policy" is driving up bills. Instead, two mechanisms remain plausible contributors: (i) the structure of rooftop-solar compensation, which shifts fixed system costs onto non-solar customers, and (ii) the rising costs of climate resilience and grid hardening—now joined by emerging load pressures from data centers.

These insights point toward a constructive policy agenda. First, regulators should modernize rate design to improve both efficiency and equity. Income-based fixed charges could help align cost recovery with the ability to pay. Second, reforms to net metering—transitioning toward cost-reflective export credits or time-varying rates—can reduce cross-subsidization without undermining distributed generation. Third, policymakers might consider shifting certain public-policy costs, such as energy-efficiency and electrification surcharges, into the broader tax base rather than embedding them in per-kWh rates. Finally, sustained investment in grid resilience is essential, but regulators should ensure that cost-recovery mechanisms protect affordability for low- and moderate-income households.

In short, the debate over renewables and electricity affordability should pivot from assigning blame to designing smarter, fairer, and more resilient rate structures. Decarbonization need not conflict with affordability—but realizing that promise requires accurate diagnosis of cost drivers and policy frameworks that evolve with the changing energy and climate landscape.

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A Appendix Results: Residential electricity prices

Table A1: Impact of RPS on CONUS Residential Electricity Price (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
RPS	2.0053***	1.4246***	1.6764***	−0.0029	0.0598
	(0.2750)	(0.1997)	(0.3865)	(0.0862)	(0.0709)
R2 Adj.	0.408	0.604	0.631	0.943	0.969
Num.Obs.	1248	1248	1248	1248	1248
R2	0.408	0.612	0.645	0.946	0.973
Year FE		Yes		Yes	Yes
State FE			Yes	Yes	Yes
Year:State FE					Yes
Year^2:State FE					Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001
Dependent Variable: Log residential electricity price [¢/kwh], in nominal USD. State clustered standard errors. RPS refers to the share of applicable retail electricity sales that should be served by renewable sources.

Table A2: Impact of RPS and Source Generation Shares on CONUS Residential Electricity Price (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
RPS	1.2889***	0.9302***	0.6577**	−0.0603	−0.0832
	(0.2359)	(0.2362)	(0.2027)	(0.1015)	(0.0784)
Utility PV & Thermal Generation	−0.8507	−1.6156*	0.3946	−0.8123*	1.1148
	(0.7851)	(0.7424)	(0.8605)	(0.4024)	(0.9691)
Residential PV Generation	5.9385*	6.6609**	3.5418	3.1459+	8.0167*
	(2.2673)	(2.2293)	(2.7259)	(1.6357)	(3.0075)
Wind Generation	0.9773***	0.4015**	1.1943***	−0.1229	−0.1092
	(0.1102)	(0.1230)	(0.1545)	(0.1076)	(0.2036)
Hydro Generation	−0.1560*	−0.1535*	−0.1691	−0.2030*	−0.1674
	(0.0653)	(0.0722)	(0.2820)	(0.0932)	(0.1609)
Pumped Storage Generation	0.2379	0.4623	1.8098	−5.3118+	−3.9884*
	(4.9398)	(5.1908)	(4.8057)	(2.8813)	(1.8330)
Natural Gas Generation	0.5189***	0.3479***	0.7992***	−0.1332	−0.1912*
	(0.0693)	(0.0975)	(0.1492)	(0.0863)	(0.0789)
Nuclear Generation	0.6014***	0.5181***	0.6284**	0.0664	−0.0976
	(0.1059)	(0.1042)	(0.1901)	(0.0956)	(0.1281)
Petroleum Generation	0.1784	1.0160**	−0.1458	−0.1166	−0.3977
	(0.3140)	(0.3276)	(0.2919)	(0.2721)	(0.2960)
Other Generation	0.3375	0.7116	1.1197+	−0.0363	−0.7372+
	(0.4323)	(0.4688)	(0.6614)	(0.4704)	(0.4333)
R2 Adj.	0.676	0.792	0.804	0.946	0.971
Num.Obs.	1248	1248	1248	1248	1248
R2	0.678	0.798	0.813	0.950	0.976
Year FE		Yes		Yes	Yes
State FE			Yes	Yes	Yes
Year:State FE					Yes
$Year^2$:State FE					Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001
Dependent Variable: Log residential electricity price [¢/kwh], in nominal USD. State clustered standard errors. The omitted comparison group is the share of coal generation. Generation is expressed in MWh as a share of the total generation for each state in a particular year.

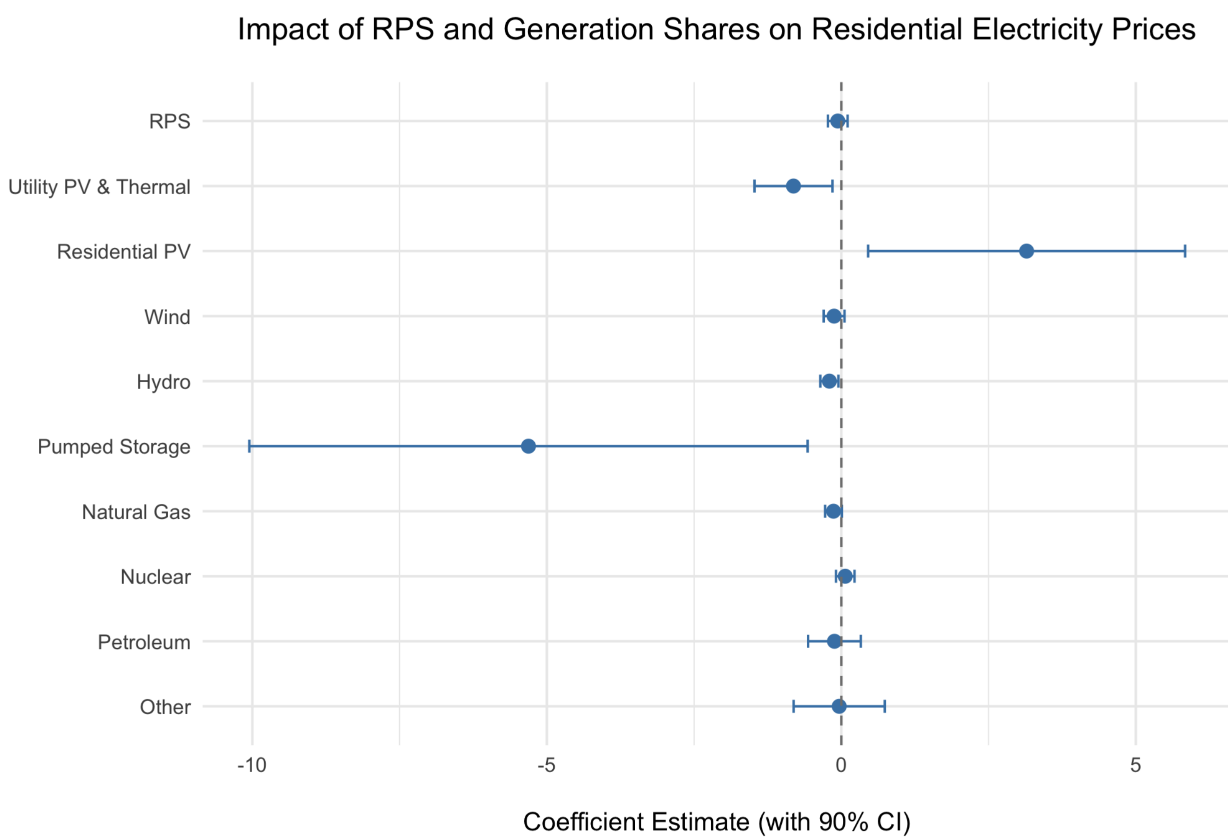
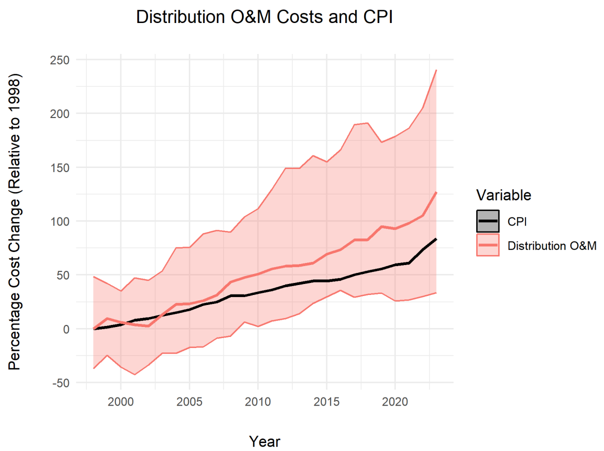
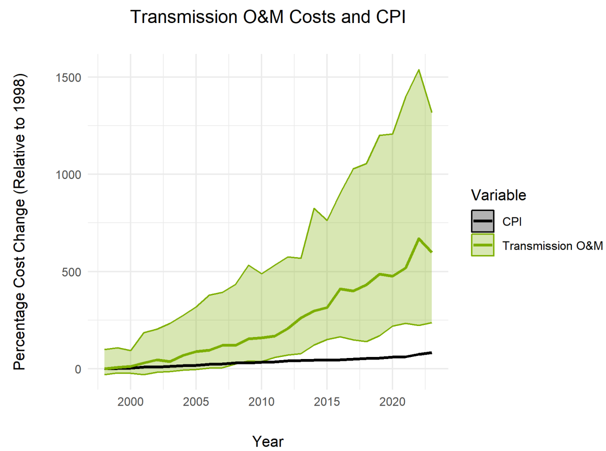


Figure A1: Coefficient plot that displays coefficient estimates from the fourth regression model displayed in Appendix Table A2 with both state and year fixed effects.

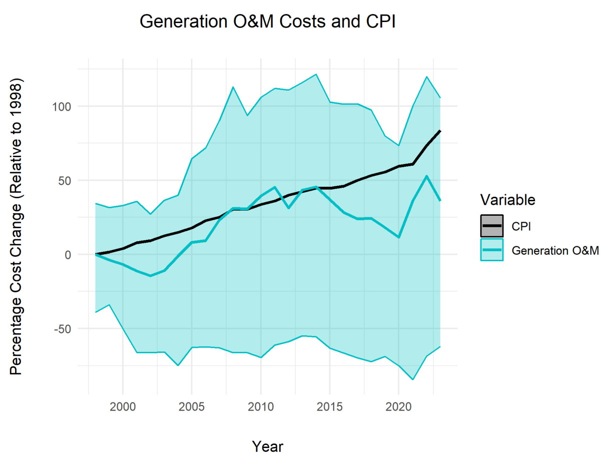
B Appendix Results: Utility costs



(a) O&M Distribution Costs



(b) O&M Transmission Costs

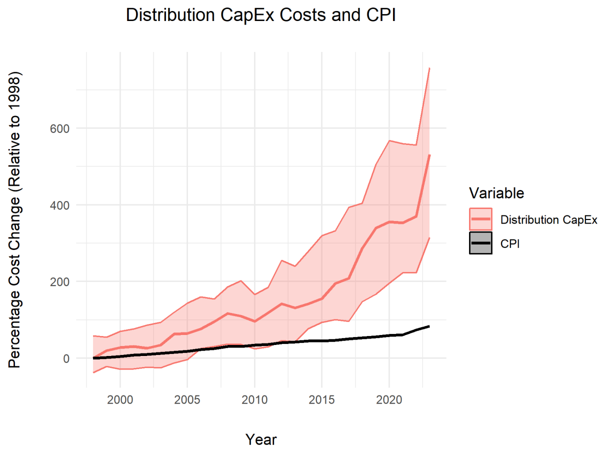


(c) O&M Generation Costs

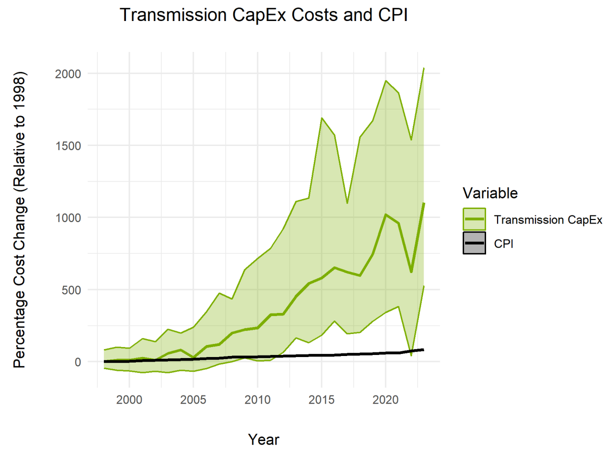
Figure A2: Trends in O&M costs for distribution, transmission, and distribution as reported in the FERC Form-1 filings. All costs are expressed as percentage changes relative to 1998 values. Distribution and transmission costs have steadily risen above the CPI, whereas generation costs have fallen below the CPI.

Table A3: Summary Statistics for FERC Form-1 O&M Costs from 1998 - 2023

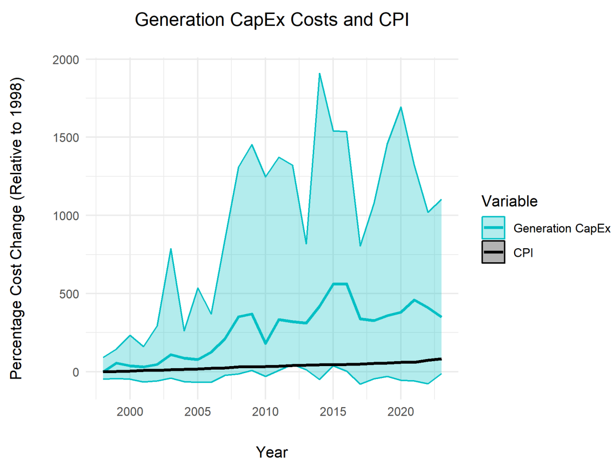
Variable	N	Mean	Std. Dev.	Min	Pctl. 25	Pctl. 75	Max
O&M Distribution [¢/kWh]	7871	0.41	1.5	0	0.17	0.39	59
O&M Transmission [¢/kWh]	7871	0.48	2.7	0	0.074	0.42	108
O&M Generation [¢/kWh]	7871	1.6	2.6	0	0.48	2.3	175



(a) CapEx Distribution Costs



(b) CapEx Transmission Costs



(c) CapEx Generation Costs

Figure A3: Trends in CapEx costs for distribution, transmission, and distribution as reported in the FERC Form-1 filings. All costs are expressed as percentage changes relative to 1998 values. All cost categories have risen, above the CPI; however, distribution and transmission costs have risen at much faster rates whereas generation costs seem to have stagnated.

Table A4: Summary Statistics for FERC Form-1 CapEx from 1998 - 2023

Variable	N	Mean	Std. Dev.	Min	Pctl. 25	Pctl. 75	Max
CapEx Distribution [¢/kWh]	7871	0.7	1.9	0	0.27	0.8	91
CapEx Transmission [¢/kWh]	7870	0.5	2.9	0	0.034	0.38	81
CapEx Generation [¢/kWh]	7870	0.69	3.6	0	0.041	0.7	290

Table A5: Impact of Source Generation Shares on Distribution Operation and Maintenance Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	26.3263**	23.1681*	14.8509*	10.8634***	6.3430*
	(8.4795)	(9.3540)	(6.5365)	(2.5367)	(2.5711)
Utility PV & Thermal Generation	−6.1496	−7.1481+	0.1085	0.5860	−2.3832*
	(3.9714)	(4.2150)	(2.2653)	(0.9167)	(1.0346)
Wind Generation	1.5856***	0.4014	1.3029*	1.2394***	−0.8007*
	(0.3542)	(0.4853)	(0.5044)	(0.3325)	(0.3047)
Hydro Generation	0.8542**	0.8243**	0.5864	0.0641	0.0195
	(0.2956)	(0.2854)	(0.9485)	(0.1076)	(0.3648)
Pumped Storage Generation	0.0890	−1.3321	−14.5478+	6.9736**	−11.2608
	(10.5017)	(10.5425)	(7.2697)	(2.3365)	(8.7479)
Natural Gas Generation	0.8738**	0.4464	1.2375***	0.7993***	−0.2779
	(0.2842)	(0.2778)	(0.3099)	(0.1630)	(0.2742)
Nuclear Generation	1.0419*	0.8709+	1.2440+	0.2332*	−0.0687
	(0.4715)	(0.4867)	(0.6878)	(0.1041)	(0.4389)
Petroleum Generation	−0.6862	0.6332	−1.5771*	−1.8015**	−0.6073
	(1.0029)	(1.1637)	(0.7059)	(0.5934)	(0.7855)
Other Generation	3.5866***	3.8816***	1.1371	−0.6264	−0.8761
	(0.6987)	(0.7327)	(2.9914)	(0.4748)	(2.0714)
R2 Adj.	0.078	0.093	0.177	0.873	0.895
Num.Obs.	7417	7417	7417	7413	7413
R2	0.079	0.097	0.183	0.876	0.898
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001

Dependent Variable: Log of distribution operation and maintenance costs of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Table A6: Impact of Source Generation Shares on Transmission Operation and Maintenance Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	29.5085***	22.9625*	17.3700*	11.8087**	5.1600
	(8.2362)	(9.5904)	(7.1109)	(3.9421)	(5.3685)
Utility PV & Thermal Generation	−9.5133**	−11.9053**	−2.4807	−0.4875	−4.9396*
	(3.4382)	(3.8051)	(2.4386)	(1.5273)	(2.1525)
Wind Generation	4.7882***	2.2568***	4.2102***	3.3850***	0.7397
	(0.4847)	(0.3928)	(0.5470)	(0.4132)	(0.5081)
Hydro Generation	0.5367+	0.4779+	1.5883*	0.0932	0.8727*
	(0.3011)	(0.2573)	(0.7633)	(0.1983)	(0.3987)
Pumped Storage Generation	−19.0179	−20.0758	1.7680	12.5348*	−16.6471
	(24.3253)	(24.5981)	(15.0092)	(5.0616)	(18.7864)
Natural Gas Generation	0.8732*	−0.0124	2.9066***	1.5349***	−0.0210
	(0.3461)	(0.3456)	(0.3583)	(0.2775)	(0.5608)
Nuclear Generation	0.1205	−0.2478	2.5961***	0.6678**	0.7058
	(0.4684)	(0.4839)	(0.6817)	(0.1940)	(0.5572)
Petroleum Generation	−2.4761	0.8915	−1.0007	−2.7944***	0.0301
	(1.6505)	(1.7151)	(1.2345)	(0.7050)	(1.3383)
Other Generation	6.1199**	6.6883***	6.5948***	−0.3172	0.5363
	(2.0212)	(1.4685)	(1.8303)	(0.8886)	(1.2940)
R2 Adj.	0.194	0.290	0.372	0.738	0.822
Num.Obs.	7579	7579	7579	7573	7573
R2	0.195	0.293	0.376	0.744	0.828
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001
Dependent Variable: Log of transmission operation and maintenance costs per kWh of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Table A7: Impact of Source Generation Shares on Generation Operation and Maintenance Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	−16.5059	−16.8738	9.9126	−2.6801	−1.2008
	(13.6690)	(13.5724)	(8.0879)	(4.4287)	(5.5999)
Utility PV & Thermal Generation	4.8336	4.8799	−5.3403*	1.2190	−0.4520
	(4.8882)	(4.9898)	(2.2678)	(1.2049)	(1.4957)
Wind Generation	0.1914	−0.2779	0.2108	0.3718+	−0.5897
	(0.3162)	(0.4529)	(0.2896)	(0.1938)	(0.4199)
Hydro Generation	−0.6347	−0.6158	−2.2351**	−0.1732**	−2.5523***
	(0.4025)	(0.4134)	(0.6402)	(0.0636)	(0.6934)
Pumped Storage Generation	12.2219	10.5042	20.4419	7.6154+	−0.5382
	(17.8004)	(17.6710)	(14.9135)	(4.2032)	(15.9903)
Natural Gas Generation	0.6650	0.5138	1.1633***	0.2149+	0.2340
	(0.3962)	(0.4112)	(0.3136)	(0.1197)	(0.5351)
Nuclear Generation	−0.9976*	−1.0252*	0.6972	0.1387	−0.5749
	(0.4949)	(0.4903)	(0.9509)	(0.1400)	(0.7764)
Petroleum Generation	−2.8830	−1.8755	1.9551+	2.6525*	4.2972**
	(2.4376)	(2.5226)	(1.1064)	(1.2148)	(1.4108)
Other Generation	−6.8322**	−7.0249**	7.3809*	−0.2712	0.9508
	(2.3569)	(2.4305)	(3.3452)	(0.3626)	(2.3844)
R2 Adj.	0.075	0.092	0.219	0.570	0.588
Num.Obs.	6740	6740	6740	6736	6736
R2	0.077	0.096	0.226	0.581	0.602
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Dependent Variable: Log of generation operation and maintenance costs per kWh of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Table A8: Impact of Source Generation Shares on Delivery Operation and Maintenance Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	26.9111***	22.0276**	16.0790**	11.1246***	5.5585
	(6.1629)	(6.9181)	(5.6023)	(2.8730)	(3.5577)
Utility PV & Thermal Generation	−6.0835*	−7.8182*	−0.6518	0.1955	−3.3148*
	(2.8031)	(3.0751)	(1.9610)	(1.0789)	(1.3676)
Wind Generation	3.4026***	1.4606***	2.8407***	2.3269***	0.1601
	(0.4035)	(0.3139)	(0.4731)	(0.3462)	(0.3189)
Hydro Generation	0.5493*	0.4984*	1.2374	0.0731	0.4502
	(0.2722)	(0.2466)	(0.7457)	(0.1473)	(0.2779)
Pumped Storage Generation	−15.7488	−16.9616	−2.0887	8.7084*	−14.5901
	(15.8349)	(16.2497)	(9.8309)	(3.4493)	(13.3902)
Natural Gas Generation	0.7259*	0.0470	2.2320***	1.1288***	−0.1698
	(0.3077)	(0.2948)	(0.3059)	(0.2065)	(0.3586)
Nuclear Generation	0.5912+	0.3083	1.9347**	0.4244**	0.3138
	(0.3433)	(0.3529)	(0.5519)	(0.1431)	(0.4481)
Petroleum Generation	−2.2437+	0.2673	−1.6322+	−2.7986***	−1.1210
	(1.1619)	(1.2306)	(0.8577)	(0.5900)	(0.9946)
Other Generation	5.1156***	5.5164***	4.0265*	−0.3619	0.1694
	(1.3002)	(0.9540)	(1.8681)	(0.6607)	(1.6286)
R2 Adj.	0.169	0.240	0.291	0.780	0.838
Num.Obs.	7695	7695	7695	7689	7689
R2	0.170	0.243	0.296	0.786	0.843
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001
Dependent Variable: Log of delivery operation and maintenance costs (sum of transmission and distribution) per kWh of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Table A9: Impact of Source Generation Shares on Generation and Delivery Operation and Maintenance Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	1.0340	−0.8932	10.1483***	9.5224***	6.7700*
	(5.4320)	(5.4675)	(2.4042)	(2.2300)	(2.9867)
Utility PV & Thermal Generation	1.4056	0.9163	−1.2424	−0.5130	−3.0236**
	(2.0577)	(2.0002)	(1.0788)	(0.9508)	(1.0872)
Wind Generation	1.3891***	0.5379*	1.2235***	1.1426***	−0.4822*
	(0.2347)	(0.2525)	(0.3288)	(0.2264)	(0.2209)
Hydro Generation	−0.3365*	−0.3365*	−0.5210	−0.0720	−0.8468*
	(0.1307)	(0.1293)	(0.6944)	(0.0704)	(0.3892)
Pumped Storage Generation	2.9138	2.2334	21.3607**	6.5674**	2.4592
	(7.9611)	(8.1071)	(6.7827)	(1.9184)	(8.4784)
Natural Gas Generation	0.4897**	0.1893	0.9430***	0.5232***	−0.5656*
	(0.1402)	(0.1526)	(0.1968)	(0.0908)	(0.2593)
Nuclear Generation	−0.5839*	−0.6985*	0.0632	0.1720*	−0.2830
	(0.2704)	(0.2701)	(0.3916)	(0.0689)	(0.3302)
Petroleum Generation	−1.8801+	−0.4587	−1.3360+	−1.9676***	−1.2034
	(0.9426)	(0.9625)	(0.7376)	(0.5029)	(0.8472)
Other Generation	1.3381*	1.3665**	1.4555	−0.1111	0.2116
	(0.5207)	(0.4935)	(1.3087)	(0.3374)	(1.6787)
R2 Adj.	0.094	0.138	0.218	0.692	0.740
Num.Obs.	7868	7868	7868	7865	7865
R2	0.095	0.141	0.224	0.699	0.749
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001

Dependent Variable: Log of total generation and delivery operation and maintenance costs (sum of generation, transmission, and distribution) per kWh of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Table A10: Impact of Source Generation Shares on Distribution Capital Expenditure Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	16.9165***	10.6299**	14.7586**	9.8219**	0.3858
	(4.3276)	(3.7784)	(5.2301)	(3.0861)	(3.3112)
Utility PV & Thermal Generation	1.3704	−0.4146	2.3710	2.7399*	−1.4175*
	(1.8453)	(1.5548)	(1.7202)	(1.2514)	(0.6812)
Wind Generation	2.4966***	0.6336+	2.7940***	2.5260***	−0.1902
	(0.2836)	(0.3611)	(0.4889)	(0.3470)	(0.2273)
Hydro Generation	0.4516+	0.3998*	1.2735	0.1115	0.3672
	(0.2395)	(0.1925)	(1.0617)	(0.1800)	(0.3523)
Pumped Storage Generation	6.3624	4.2453	9.3390	12.8904***	−4.5693
	(5.1069)	(5.0712)	(9.1801)	(3.6108)	(6.4752)
Natural Gas Generation	1.2555***	0.5808**	2.3209***	1.3775***	−0.1408
	(0.2324)	(0.1782)	(0.3213)	(0.2291)	(0.2508)
Nuclear Generation	0.9258***	0.6526**	1.8778**	0.5248**	0.4013
	(0.2221)	(0.2012)	(0.5348)	(0.1634)	(0.4300)
Petroleum Generation	−3.1208***	−1.2102	−2.5174*	−3.1076***	−1.7032*
	(0.7497)	(0.8856)	(1.0086)	(0.4936)	(0.7323)
Other Generation	1.7081+	2.4321***	2.8862	−0.9960	0.5000
	(0.8672)	(0.5138)	(1.8142)	(0.9413)	(1.1502)
R2 Adj.	0.234	0.317	0.307	0.669	0.775
Num.Obs.	7232	7232	7232	7228	7228
R2	0.235	0.320	0.312	0.676	0.783
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Dependent Variable: Log of distribution capital expenditure costs per kWh of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Table A11: Impact of Source Generation Shares on Transmission Capital Expenditure Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	14.1903+	6.3375	20.7139+	19.9608**	7.7521
	(7.7351)	(6.1304)	(11.8896)	(7.0751)	(4.7261)
Utility PV & Thermal Generation	−0.4827	−2.9892	−2.2167	−1.5903	−7.8119***
	(2.2695)	(2.0382)	(3.4237)	(1.8515)	(1.6361)
Wind Generation	5.4735***	2.1757**	5.6014***	4.7457***	0.1508
	(0.6311)	(0.6261)	(0.6987)	(0.4906)	(0.3288)
Hydro Generation	0.6407+	0.5889+	2.2208+	0.0816	0.5519+
	(0.3408)	(0.3236)	(1.2233)	(0.2777)	(0.3085)
Pumped Storage Generation	21.3185**	18.7339**	40.7894*	20.0035**	−3.7237
	(7.1871)	(6.2594)	(16.5883)	(5.8456)	(14.5683)
Natural Gas Generation	2.2662***	1.1564***	4.2380***	2.2640***	−0.1315
	(0.3466)	(0.2736)	(0.3991)	(0.3300)	(0.3192)
Nuclear Generation	0.7901*	0.3502	2.8360**	0.7194**	0.1667
	(0.3687)	(0.3821)	(0.9004)	(0.2626)	(0.5909)
Petroleum Generation	−6.0173***	−1.9565+	−3.4191*	−7.0181***	−3.5049**
	(1.0427)	(1.0958)	(1.3096)	(0.9193)	(1.2020)
Other Generation	3.3490**	3.9290***	8.9927**	−0.2711	2.7338
	(1.1433)	(0.7022)	(3.3092)	(1.3577)	(1.6514)
R2 Adj.	0.204	0.291	0.268	0.554	0.657
Num.Obs.	6998	6998	6998	6992	6992
R2	0.205	0.295	0.274	0.565	0.669
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001
Dependent Variable: Log of transmission capital expenditure costs per kWh of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Table A12: Impact of Source Generation Shares on Generation Capital Expenditure Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	−13.9889	−16.8049	7.1512	4.1753	0.8060
	(10.4565)	(10.7970)	(9.5291)	(3.7744)	(6.4564)
Utility PV & Thermal Generation	6.8940+	5.5239	−2.7864	−0.7093	−2.2840
	(3.7714)	(3.6413)	(2.6457)	(1.5792)	(2.2780)
Wind Generation	2.7045***	0.3209	2.9001***	2.6580***	0.7749*
	(0.3711)	(0.5057)	(0.4340)	(0.2999)	(0.3480)
Hydro Generation	−0.3113	−0.3356	−0.3392	−0.0858	−0.1835
	(0.3303)	(0.3296)	(0.8151)	(0.1580)	(0.3871)
Pumped Storage Generation	5.5364	4.1038	34.1077*	14.4308**	0.4937
	(14.0911)	(13.1783)	(16.0414)	(4.9648)	(11.7307)
Natural Gas Generation	0.4406	−0.4876	2.9675***	1.3567***	0.5604
	(0.4493)	(0.4197)	(0.2888)	(0.1748)	(0.3708)
Nuclear Generation	−0.2296	−0.4723	0.5555	0.4293*	−0.6930
	(0.4583)	(0.4377)	(0.9196)	(0.1704)	(0.7453)
Petroleum Generation	−6.7853**	−2.1840	−2.2486**	−2.7086**	1.7280+
	(1.9583)	(1.9077)	(0.8268)	(0.9903)	(0.9515)
Other Generation	−4.5976**	−4.6245*	8.9440*	0.1576	−0.0373
	(1.5534)	(1.8142)	(4.3644)	(0.9500)	(3.2317)
R2 Adj.	0.080	0.177	0.192	0.442	0.510
Num.Obs.	6517	6517	6517	6509	6509
R2	0.081	0.181	0.198	0.456	0.528
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001

Dependent Variable: Log of generation capital expenditure costs per kWh of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Table A13: Impact of Source Generation Shares on Delivery Capital Expenditure Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	19.3605**	13.2424+	16.2437+	12.7794**	3.8746
	(6.1613)	(7.3009)	(8.1676)	(3.9864)	(3.6162)
Utility PV & Thermal Generation	−0.9537	−3.0774	1.0873	1.2068	−3.7973**
	(2.3745)	(2.7555)	(2.2041)	(1.3457)	(1.1451)
Wind Generation	3.5757***	1.3168*	3.4028***	3.0524***	−0.0605
	(0.5780)	(0.5370)	(0.6476)	(0.4577)	(0.2654)
Hydro Generation	0.8452*	0.7867*	1.6680	0.0980	0.2655
	(0.3504)	(0.3214)	(1.0926)	(0.2076)	(0.3114)
Pumped Storage Generation	8.4115	6.4516	19.3209	15.5179***	−4.3811
	(13.8393)	(14.6731)	(12.9918)	(4.2456)	(7.7429)
Natural Gas Generation	1.7468***	0.9353**	3.1682***	1.6813***	−0.0711
	(0.3418)	(0.3093)	(0.3802)	(0.2609)	(0.2586)
Nuclear Generation	1.0907**	0.7609+	2.4576**	0.6176**	0.5152
	(0.4003)	(0.4148)	(0.7220)	(0.1920)	(0.4065)
Petroleum Generation	−3.3114***	−0.7118	−2.3002*	−4.4666***	−2.4548*
	(0.7880)	(0.8697)	(1.0180)	(0.6464)	(0.9155)
Other Generation	3.3768*	3.9873***	5.3667*	−0.4472	2.2459+
	(1.3988)	(0.9888)	(2.0961)	(1.0673)	(1.2498)
R2 Adj.	0.190	0.252	0.282	0.723	0.797
Num.Obs.	7516	7516	7516	7510	7510
R2	0.191	0.255	0.287	0.729	0.804
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001
Dependent Variable: Log of delivery capital expenditure costs per kWh of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Table A14: Impact of Source Generation Shares on Generation and Delivery Capital Expenditure Costs (1998-2023), in nominal $

	(1)	(2)	(3)	(4)	(5)
Residential PV	13.1083**	7.8453	15.3416+	12.3405**	5.3027
	(4.1866)	(4.7859)	(7.6589)	(3.8037)	(3.8435)
Utility PV & Thermal Generation	1.0198	−0.5339	0.3026	0.2429	−3.4563*
	(1.7703)	(1.8726)	(2.3581)	(1.4524)	(1.5285)
Wind Generation	3.5100***	1.1912**	3.3399***	2.9935***	0.2546
	(0.4164)	(0.3480)	(0.5763)	(0.3983)	(0.2345)
Hydro Generation	0.2389	0.2117	0.7477	0.0419	0.3865
	(0.3147)	(0.2658)	(1.0702)	(0.1859)	(0.2843)
Pumped Storage Generation	5.3222	3.9004	26.5713+	14.3333**	−1.5384
	(9.0027)	(8.9946)	(15.5429)	(4.1114)	(5.5858)
Natural Gas Generation	1.1055**	0.2469	2.6999***	1.5521***	−0.1208
	(0.3203)	(0.2808)	(0.2813)	(0.2033)	(0.2116)
Nuclear Generation	0.5838*	0.2607	1.6781**	0.5336**	0.1147
	(0.2553)	(0.2493)	(0.6162)	(0.1728)	(0.3057)
Petroleum Generation	−4.5875***	−1.0795	−3.3720***	−4.7291***	−2.0437**
	(0.7205)	(0.7931)	(0.7510)	(0.4884)	(0.7493)
Other Generation	2.8618*	3.1368***	5.4366*	−0.2457	0.5064
	(1.0757)	(0.7690)	(2.1102)	(0.9560)	(0.8474)
R2 Adj.	0.161	0.269	0.260	0.572	0.669
Num.Obs.	7804	7804	7804	7801	7801
R2	0.162	0.272	0.265	0.582	0.680
Year FE		Yes			Yes
State FE			Yes		Yes
Utility FE				Yes	Yes

+ p <0.1, * p <0.05, ** p <0.01, *** p <0.001

Dependent Variable: Log of total generation and delivery capital expenditure costs (sum of generation, transmission, and distribution) per kWh of total electricity sold in nominal USD [¢/kWh]. Costs reported at a utility level and generation shares are reported at the state level. The omitted comparison group is the share of coal generation. State clustered standard errors.

Contact.

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MIT CEEPR

Center for Energy and Environmental Policy Research

MIT Center for Energy and Environmental Policy Research
Massachusetts Institute of Technology
77 Massachusetts Avenue, E19-411
Cambridge, MA 02139-4307
USA

ceepr.mit.edu

MASSACHUSETTS INSTITUTE OF TECHNOLOGY