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LETTER

The missing correlation between the potential rate impacts of rooftop solar and the timing of state net metering policy revisions

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Abstract

Residential solar photovoltaic (PV) output in most states is credited at the retail electricity rate, a policy commonly known as net metering. Twelve states have replaced net metering with alternative rate structures that reduce PV adopter bill savings. Proponents of these revisions argue that net metering increases the electricity rates of customers without PV. Here, we analyze the degree to which the timelines of net metering revisions have correlated with potential electricity rate impacts. We estimate that potential rate impacts at the end of 2023 were less than 1% of typical customer bills in 37 of 44 states that have offered net metering. There are no statistically significant differences in average or median estimated rate impacts between states that have and have not revised net metering. Nine of the states that had revised net metering did so when estimated impacts were less than 1% of typical customer bills. Many states have retained net metering into higher PV deployment levels with increased risk of potential rate impacts. Only two states—California and Hawaii—retained net metering beyond estimated rate impacts of 5%, and both have revised net metering. These findings do not suggest a clear, consistent link between net metering revision timelines and potential rate impacts. The timing and nature of net metering revisions are ultimately policy decisions based on state-level priorities and considerations.

1. Introduction

Nearly five million households had adopted rooftop solar photovoltaic (PV) systems in the United States by the end of 2023 [1]. Rooftop PV adoption can yield long-term financial returns through savings on utility electricity bills. In the United States, these savings are often bolstered by a rate structure known as net metering, where rooftop PV output used on-site and exported to the grid is all credited at the same retail rate of electricity. Forty-three (43) states and Washington, DC have, at some point, required regulated electric utilities to implement net metering. Our calculations suggest that around 84% of US. households lived in states with net metering requirements before 2014. Net metering has been a key enabler of residential PV adoption in the United States [2].

Net metering is largely viewed as an administratively simple and acceptable default rate for residential PV adopters in nascent PV markets [2, 3]. Many states have also supported net metering to explicitly enable residential PV adoption and achieve state clean energy goals [4]. Nonetheless, 12 states have replaced net metering with alternative compensation structures, and most states are at least considering revisions to net metering policies [5]. Alternative structures implemented to date have reduced PV bill savings relative to net metering, primarily by crediting PV exported to the grid at less than the retail rate of electricity [2]. There is evidence that net metering revisions have decelerated rooftop PV deployment [6–8].

Proponents of net metering revisions have argued that net metering increases the electricity rates of customers without PV [9]. Prior research documents how discourse about adverse rate impacts has driven proposed and implemented net metering revisions [4, 10], and several studies have estimated the potential magnitudes of these adverse rate impacts [11–16]. Yet no study, to our knowledge, has explored the connections between the role of perceived adverse rate impacts in net metering revisions and the plausible magnitudes of those impacts. That is, it remains an open question whether net metering revisions are consistently supported by quantitative evidence of potential rate impacts. Here, we fill that research gap by exploring the degree to which the timelines of net metering revisions correlate with the estimated magnitude of potential rate impacts. We begin with a brief review of qualitative and quantitative descriptions of the potential rate impacts of net metering.

2. Background

Electric utilities invest in grid infrastructure and operations to ensure a reliable electricity supply. Utilities recoup their investments by charging customers for grid electricity use. Public utility commissions regulate utility charges to ensure that utilities recoup enough revenues to cover all costs while preventing excessive profits. Reduced grid demand from rooftop PV adoption reduces utility costs (e.g. fuel costs) and reduces utility revenues. The impacts of rooftop PV adoption on costs will not perfectly match the impact on revenues because no electricity rate perfectly reflects the marginal costs of serving individual customers [4]. In effect, rooftop PV adoption can create situations where utilities recoup more or less revenue from rooftop PV customers than the costs that had been allocated to those customers. In theory, the impacts of these discrepant impacts can be managed through the integration into rate design of PV adoption forecasts [17]. However, some stakeholders argue that under-recovery of revenues from PV customers is reallocated in ways that increase the rates of customers without PV [18]. Several scholars have similarly concluded that rooftop PV deployment can increase the rates of customers without PV, largely through theoretical modeling of utility costs [12–15, 19]. Nonetheless, the potential rate impacts of net metering do not run universally in one direction across contexts [11]. Many studies of the value of rooftop PV suggest that utilities may over- rather than under-recover revenues from rooftop PV customers (see figure 1), such that rooftop PV adoption may increase or potentially decrease the rates of customers without PV across different contexts.

Barbose [11] develops a framework for understanding potential net metering rate impacts that will be useful for our methodology developed in section 3. Retail electricity rates are generally based on the average costs of serving individual customers, known as the cost of service (CoS). CoS-based rates are imprecise, since ratemaking reflects an imperfect allocation of costs to individual customers. However, as a simplifying assumption, retail rates will generally approximate the CoS. Further, PV generation can both reduce grid costs (e.g. reduced fuel costs) and create new costs (e.g. from reverse current flows on distribution systems). Barbose and others refer to the net grid benefit of PV as the value of solar (VoS). For reasons that will be more fully explained in section 3, Barbose observes that net metering will tend to increase retail electricity rates when the net benefits of PV are less than the CoS, i.e. when VoS $<$ CoS, and that, conversely, net-metered PV will tend to reduce rates when VoS exceeds CoS.

Several studies estimate the magnitude of these potential rate impacts. To compare results across studies, we present all results in terms of potential percentage changes in residential customer grid electricity bills. Estimated potential rate impacts vary considerably across studies based largely on assumptions about rooftop PV deployment levels, which we define here as the percentage of households that have adopted PV in some defined area. Satchwell *et al* [12] estimate potential rate impacts of around 0%–4% under various scenarios with a 10% deployment level. Barbose [11] estimates potential rate impacts in the range of $\pm$0.2% at the deployment levels at the time of the study ($<$1%), growing to a projected $\pm$5% in a scenario with 10% deployment. Barbose notes that existing rate impacts at the time of the study were 'negligible' relative to other factors that affect retail electricity rates. Johnson *et al* [13] estimate potential rate impacts of around 1%–2% in a scenario with around 3% deployment and that impacts could range up to 14% in a scenario with around 16% deployment (we extrapolated these deployment levels from other assumptions in the study). Boampong and Brown [14] estimate rate impacts of around \$26–141 per kilowatt of installed PV capacity in 2018. Multiplying those estimated impacts by all PV installed in southern California by the end of 2018 and dividing those impacts across residential customers without PV yields an implied rate impact of around 1%–5% of typical bills. Borenstein *et al* [16] estimate annual rate impacts in California in 2019 in the range of \$100–230, which translates to about 7%–17% based on typical bills in that state. Using a similar approach, Borenstein [20] updates those estimates for rate impacts in 2024 with an estimated range of 7%–22%.

To summarize, previous estimates suggest that the magnitudes of potential rate impacts generally fall in the range of 0%–5% in most contexts, but may range above 10% in certain contexts, such as California, with relatively high PV deployment and a large portion of fixed costs recovered through volumetric rates. These results generally suggest that the risk of rate impacts positively correlates with PV deployment levels.

Twelve states had replaced net metering with alternative structures by the end of 2024, with another state slated to end net metering on 1 January 2025. Insofar as these rate revisions reflect solutions to potential rate impacts, one would expect the timing of revisions to correlate with the estimated magnitude of potential rate impacts in different states. No study, to our knowledge, has attempted to document the existence of such a correlation. The remainder of this study explores whether such a correlation exists.

3. Methodology

For the purposes of this study, net metering is defined as compensation for consumed and exported rooftop PV output at the full retail electricity rate. Net metering requirements refer to statewide mandates that require at least a subset of utilities to implement net metering. According to that definition, we identified 12 states that had once required net metering but had implemented alternative compensation structures by the end of 2024. For simplicity, we refer to these alternative structures as 'revisions.' We excluded states that implemented revisions that affected PV compensation while retaining retail-rate net metering, such as New York (offers an optional value-of-solar tariff but customers are still defaulted into net metering) and North Carolina (added required fixed charges for PV customers but retained retail-rate net metering up to customers' monthly total consumption). Illinois was scheduled to become the 13th state to revise net metering with the implementation of an alternative structure on 1 January 2025.

We constructed a timeline of net metering revisions based on an assessment of state net metering proceedings as documented in various sources, primarily the Database of State Incentives for Renewables & Efficiency, Apadula *et al* [5], and National Academies [2]. The exact timing and nature of net metering revisions is not always clear. For this reason, we implemented our analysis at an annual level to avoid depicting a false level of precision. Our analysis of net metering timelines should be understood as a good approximation of the relationship between key dates and PV deployment. PV deployment levels were estimated using annual net metering data from the Energy Information Administration (Form EIA-861 M) and state-level household estimates from the US. Census. PV deployment can be assessed in many ways. Another common approach is to calculate PV installed capacity as a share of the grid's total installed capacity. We explored alternative PV deployment metrics and found that the choice of metric does not significantly affect the core conclusions of this study.

We estimate the potential rate impacts of net metering through a modified version of a model first described by Barbose [11]. The model calculates potential rate impacts based on four parameters:

$$ri = d\left(\frac{r}{\text{CoS}} - \frac{\text{VoS}}{\text{CoS}}\right) \tag{1}$$

where ri is the rate impact in percentage terms, d is the cumulative PV deployment level (% of households that have adopted PV), r is the retail rate at which PV output is compensated, VoS is the estimated VoS (as defined in section 2), and CoS is the average CoS (as defined in section 2). Barbose's model usefully reduces the estimation of PV rate impacts into two key ratios: the ratio of the retail rate to the average CoS (r/CoS) and the ratio of the VoS to the CoS (VoS/CoS). In theory, the retail rate r in a typical cost-based rate structure should roughly approximate the utility's average CoS. Under that assumption, the rate impact model simplifies to:

$$ri = d\left(1 - \frac{\text{VoS}}{\text{CoS}}\right). \tag{2}$$

With that simplification, rate impacts can be estimated from the PV deployment rate and the VoS/CoS ratio. As argued by Barbose, the VoS/CoS ratio is highly uncertain. To build a distribution of VoS/CoS ratios, we infer the ratios from state- and utility-commissioned VoS studies and studies of net metering rate impacts. Barbose compiles VoS results and estimates 14 VoS/CoS ratios from state- and utility-level VoS reports commissioned before 2017. Fine *et al* [21] compile VoS estimates from three state-level studies. We extrapolated VoS/CoS ratios from those estimates based on Energy Information Administration data for state-level average retail electricity rates for the years of the VoS estimates. We estimate VoS/CoS ratios using reported VoS estimates from five additional state-level studies not reflected in Barbose or Fine *et al* from Connecticut [22], Hawaii [23], Maryland [24], Montana [25], and New Hampshire [26]. In all cases we use VoS/CoS ratios based only on utility costs and benefits—i.e., excluding social and environmental benefits—to ensure that we accurately estimate the *rate* impacts of rooftop PV. From the process above we built a distribution of 22 VoS/CoS estimates as illustrated in figure 1.

We use the distribution depicted in figure 1 to extrapolate VoS/CoS ratios across all states. We apply distinct methods across states depending on the availability of state- and utility-level VoS studies (table 1). To generate reasonable confidence intervals we assume a lower-bound VoS/CoS ratio of 0.4 across all states, an estimate consistent with Barbose [11] and consistent with the lower end of the distribution in figure 1. For most states we assume an upper-bound VoS/CoS ratio of 1, a conservative choice considering that 10 of the

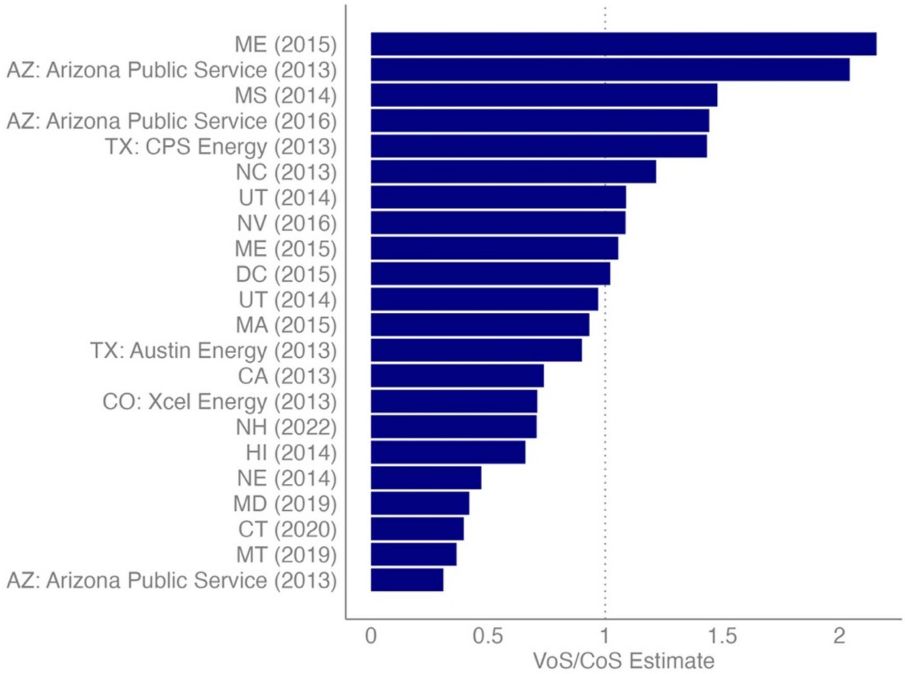

Figure 1. Distribution of VoS/CoS estimates from state- and utility-level VoS studies.

22 VoS studies imply a VoS/CoS ratio of greater than 1. California presents an exceptional case in many regards. California's residential rate structures are relatively complex, with rates that vary based on level of use and required time-of-use rates for recent PV adopters. Further, California utilities recoup an exceptionally large share of fixed costs through volumetric ($/kWh) rates [16], creating cost distortions that may augment rate impacts [14] and reduce the validity of the methodology described in equation (2). For these reasons, for California we rely on previous rate impact estimates rather than deriving those impacts from VoS/CoS ratios. As noted in section 2, Borenstein *et al* [16] estimate rate impacts in California in 2019 in the range of 7%–17%, while Borenstein [20] updates impacts into 2024 to 7%–22%. We used the midpoints of these two ranges—12% and 14.5%—as point estimates for rate impacts in California in 2019 and 2023, and estimated rate impacts for the remaining years by using those estimates to back out a VoS/CoS ratio to implement into equation (2).

Estimated rate impacts can be interpreted as the percentage change in the electricity payments of a typical residential electricity customer. In some cases, we convert relative rate impacts into absolute terms of $/customer/month based on state-level average retail electricity rates and residential electricity use data from the Energy Information Administration. These estimates assume that the rate impacts of net-metered residential customers are addressed through utility cost reallocations among other residential customers. These metrics provide an estimate of the maximum impact of net metering on the bills of customers without PV if utilities reallocated all unrecovered costs to charges on those customers. In practice, potential rate impacts depend on rate design and how under-recovered utility costs are reallocated across customer groups. Importantly, our estimates reflect the potential rate impacts that can arise due to mismatches in the electricity system costs and benefits of PV. Our method does not account for the broader social and environmental benefits of PV, because those values do not affect potential rate impacts. Still, the estimated social and environmental benefits of rooftop PV can be substantial. Analyses that include social and environmental benefits often conclude that the total benefits of rooftop PV exceed the costs [6, 18]. Any potential net metering rate impacts could potentially be justified as a means of achieving those social and environmental benefits.

4. Results

Three states revised net metering before 1% of households had adopted PV, seven states revised net metering with PV deployment in the range of 1%–5%, and two states (California and Hawaii) revised net metering at deployment above 10% (figure 2). Most states with active net metering requirements have deployment levels

Table 1. VoS/CoS assumptions.

Group	Point estimate	Lower-bound estimate	Upper-bound estimate
States with multiple VoS studies: AZ, ME, TX, UT	Average VoS/CoS ratio across studies within each state	0.4	Highest VoS/CoS ratio across studies
States with single VoS study (except California and Hawaii): CO, CT, DC, HI, MA, MD, MS, MT, NC, NE, NH, NV	VoS/CoS ratio from study within each state	0.4	1[a]
California	N/A	0.4	0.84[b] (see point estimate description for 'All other states')
All other states	0.84: The average VoS/CoS ratio across 22 VoS studies weighted by the number of net-metered customers in each state in the year of each study	0.4	1

[a] Except Hawaii, where we apply an upper-bound of 0.84. [b] In the cases of California and Hawaii, available evidence suggests that the VoS/CoS ratio is less than 1 due to relatively high PV deployment rates and unique rate structure issues. We therefore apply this more conservative upper-bound restriction on the VoS/CoS ratio, which equates to larger estimated potential rate impacts.

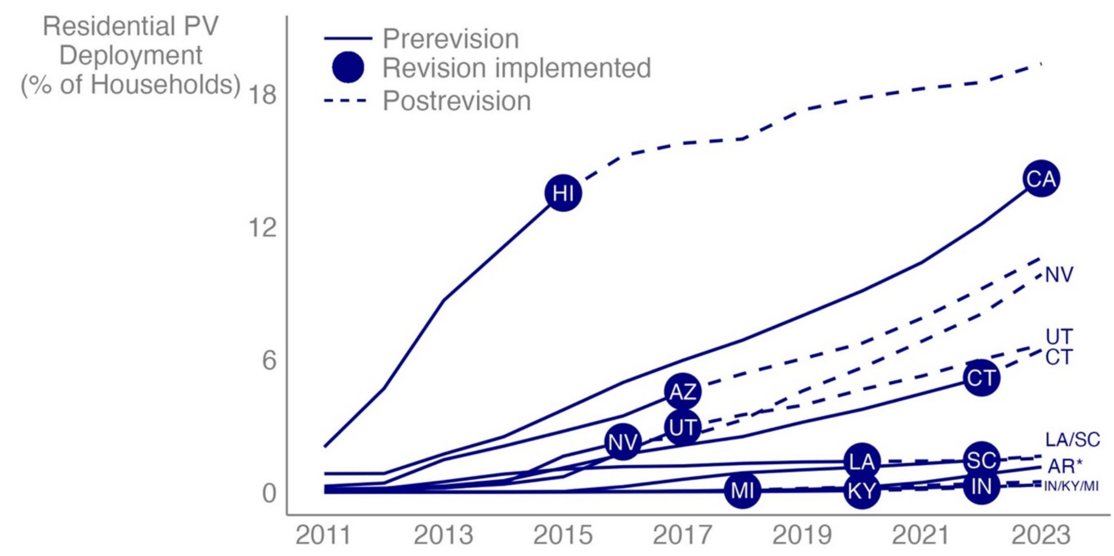

Figure 2. Cumulative residential PV deployment levels before and after net metering revisions. *Arkansas passed legislation to revise net metering in 2023 and implemented the revision in 2024.

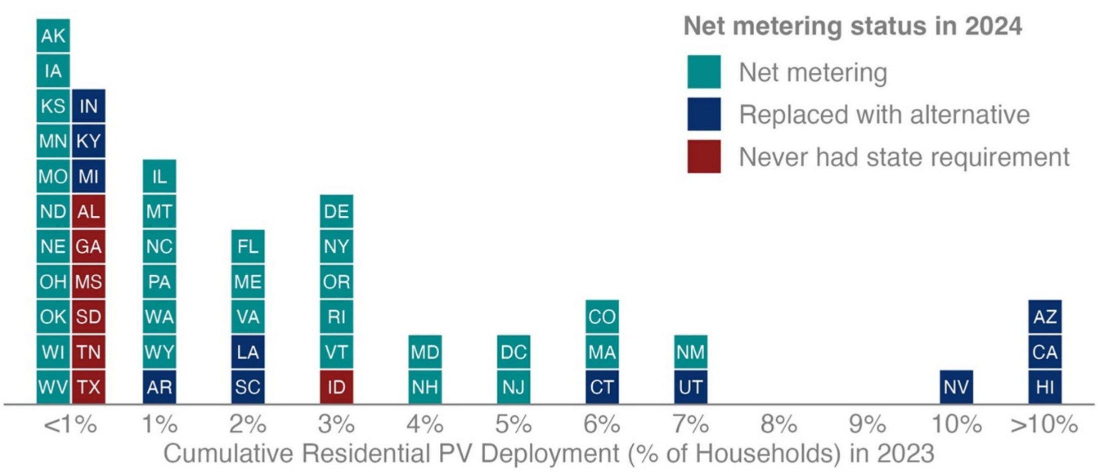

Figure 3. State-level net metering status and cumulative residential PV deployment levels.

in the range of 1%–7% (figure 3). These results do not suggest a clear correlation between the timing of net metering revisions and PV deployment levels.

Figure 4 illustrates estimated rate impacts across the 44 states (including Washington, DC) that have required net metering at some point. The *x*-axis represents cumulative deployment at the end of 2023 for states that have maintained net metering or in the year in which revisions were implemented in the 12 states that revised net metering. The error bars represent the upper and lower bounds described in section 3 and reflect the high degree of uncertainty in the analysis. Positive rate impacts mean that net metering could plausibly increase the rates of customers without PV. Estimated ranges in six states reach below zero, representing cases where estimated impacts could reduce the rates of customers without PV. Cases where point estimates fall toward one extreme of the range reflect instances where state- or utility-commissioned studies estimated low or high values of solar relative to our assumptions described in section 3. Figure 5 depicts estimated rate impacts leading up to net metering revisions following the same method.

The estimated potential rate impact is less than 1% of a typical customer's bill in 37 of the 44 states, including 9 of the 12 states that have revised net metering. In absolute terms, estimated impacts are less than \$1/customer/month in 38 states and 9 states that have revised net metering. In annual absolute terms, the median estimated impact is \$3.8/year, with an interquartile range from \$1.8/year (25th percentile) to \$9.1/year (75th percentile). Point estimates for rate impacts are greater than 1% in 7 states and greater than 2% in 4 states: Maryland (2.6%), Connecticut (3%), Hawaii (5%), and California (13%).

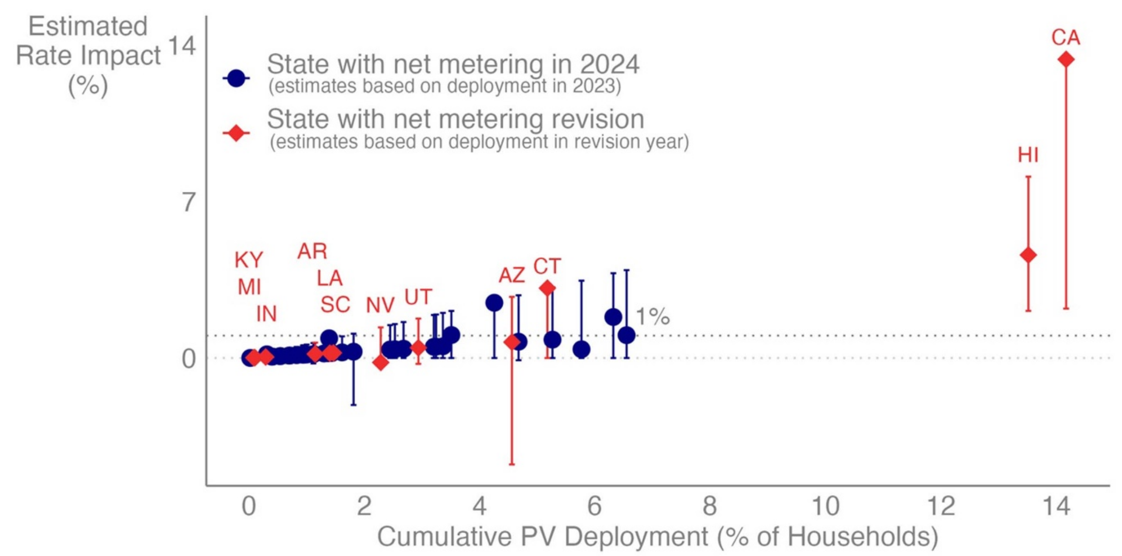

Figure 4. Estimated rate impacts (% of monthly customer bill). Figure reflects 44 states (including Washington, DC) that required net metering at some point. Error bars represent lower- and upper-bound estimates based on assumptions described in table 1.

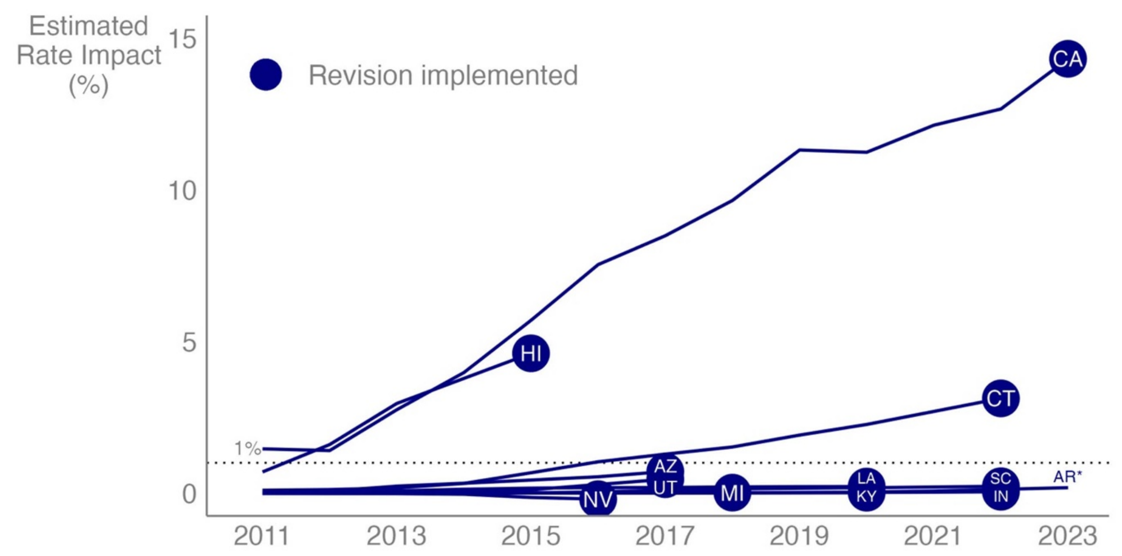

Figure 5. Estimated rate impacts leading up to net metering revisions.

Insofar as net metering revisions are prompted by concerns about potential rate impacts, one would expect that states that have revised net metering would have higher estimated impacts than states that have retained net metering. The data do not suggest that a consistent correlation exists (figure 6). No state with active net metering requirements has estimated rate impacts above 3%, and only California retained net metering requirements beyond estimated rate impacts of 10%. The average rate impact among states that revised net metering was 1.9%, a result driven largely by California. The median estimated relative impact in states that had revised net metering is 0.2%, with a median annual absolute impact of \$3.5/year. The relative average estimated impact is higher in states that had revised net metering than in states that have retained net metering (0.4%), though the difference is not statistically significant ($t = 1.3$), and the median impact is the same across states that had and had not revised net metering (0.2%). Most states that have revised net metering did so before estimated rate impacts exceeded 1% of typical electricity bills or \$1/customer/month in absolute terms. Overall, these results suggest that relatively high PV deployment levels and potential rate impacts (e.g. >5%) may drive net metering revisions, but the magnitude of potential rate impacts does not meaningfully explain the timing of net metering revisions in most states.

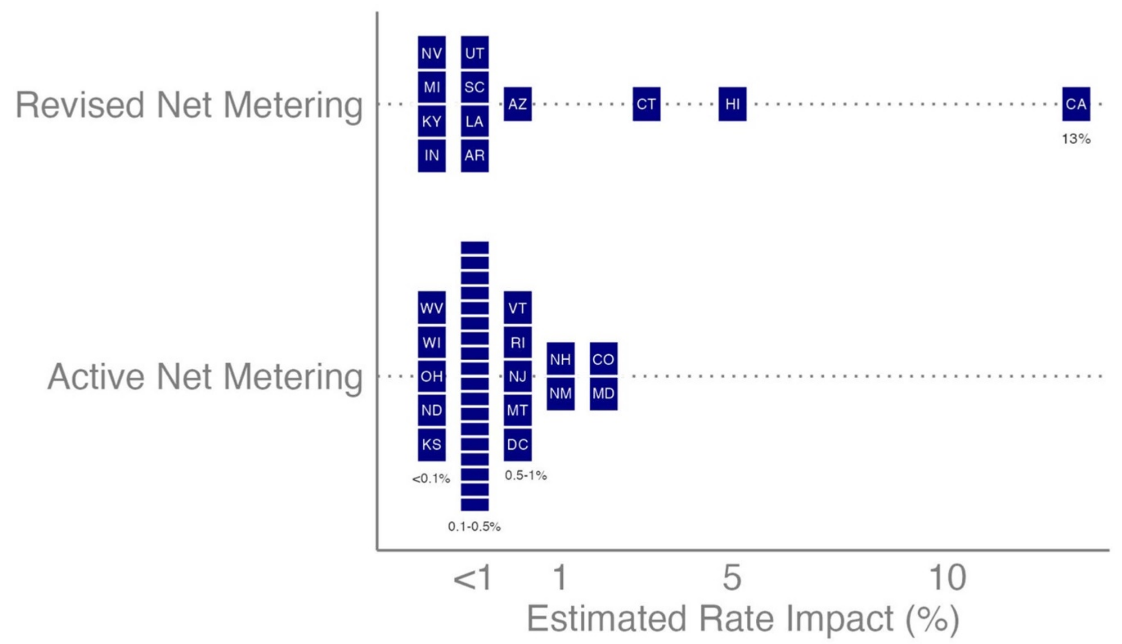

Figure 6. Estimated rate impacts in states that have and have not revised net metering. Values represent estimates in year of net metering revisions in states that have revised net metering and estimates in 2023 for states with active net metering.

5. Discussion and conclusions

Arguments for revisions to PV net metering policies often cite potential risks of adverse impacts on the electricity rates of customers without PV. Prior research has estimated the magnitude of these impacts, but the literature has not yet explored the potential connections between estimated rate impacts and net metering revisions. Our analysis suggests that the timing of net metering revisions has not consistently correlated with residential PV deployment levels or potential rate impacts. Of the 12 states that revised net metering, 9 did so when residential deployment was 3% or less and the potential rate impacts of net metering were likely less than 1% of typical residential bills, or less than $1/customer/month. Many states have retained net metering at substantially higher deployment levels with increased risk of potential rate impacts. There are no statistically significant differences in estimated average or median rate impacts between states that have and have not revised net metering. At deployment above 10% and rate impacts around $5–$20/month (3%–15% of typical customer bills), the sample size is small—only California and Hawaii have reached these levels with net metering policies in place, and both subsequently revised their policies. These findings do not suggest there is a clear, consistent link between the potential rate impacts of net metering and state net metering revisions. Here, we explore two potential explanations for this lack of a relationship, and conclude by suggesting areas for further research to develop and explore other potential explanations.

First, rate design is a practice of translating utility costs into just and reasonable rates for electricity customers (note that 'just and reasonable' is the precise term commonly used in rate design) [10, 27]. What constitutes 'just and reasonable' ultimately depends on the subjective evaluation of regulators across states with distinct contexts. One regulator may perceive that a potential rate impact of, for instance, a 2% increase in the rates of customers without PV can be justified by the broader social and environmental benefits of rooftop PV adoption. Another regulator in another state may view the same impact as unjust and unreasonable in a different state context. Heterogeneous subjective evaluations of potential rate impacts may ultimately muddle any signal of a relationship between rate impacts and net metering revisions. Future research could explore the degree to which heterogeneous evaluations of potential rate impacts can explain PV policy outcomes.

Second, proponents of net metering revisions frequently invoke principles such as fairness rather than providing quantitative evidence about rate impacts [4, 10]. A common principle-based argument is that net metering rate impacts are regressive, given that relatively affluent rooftop PV adopters ostensibly benefit from increased rates on lower-income customers without PV [4, 10]. Rate regulators may be persuaded by principle-based arguments about rate impacts even in the absence of quantitative evidence [4]. As a result, the magnitudes of potential rate impacts are not necessarily relevant to regulatory evaluation of those impacts, or at least the magnitudes are only one of several factors that affect those evaluations.

The lack of a correlation suggests there is no universal threshold of PV deployment or potential rate impacts that triggers regulators to revise net metering. Some states revised net metering at relatively low PV deployment levels and potential rate impacts while others have maintained net metering up to levels with risks of potentially larger rate impacts. The timing and nature of net metering revisions are ultimately policy decisions based on balancing state-level priorities and considerations and the potential costs and benefits of different rate structures.

We conclude by suggesting areas for further research. Our study focuses primarily on what has occurred with respect to the timelines of state net metering revisions. Future research could analyze more explanatory factors to better understand why different states revised net metering at different points. That future research could include analysis of factors such as distinct electricity rate structures, state-level support for renewable energy, and the roles of different stakeholders (e.g. consumer groups, environmental groups, utilities). In contrast to our high-level nationwide study, future work could focus on specific state contexts to better identify and understand state-level idiosyncrasies that explain net metering timelines. Overall, our work suggests that net metering revision timelines cannot be meaningfully explained by the magnitude of rate impacts, opening the door to future research to explore the factors that do meaningfully explain those timelines.

Data availability statement

The data that support the findings of this study are openly available at the following URL/DOI: data.nrel.gov. Data will be available from 01 September 2025.

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