Estimates of the Marginal Curtailment Rates for Solar and Wind Generation

Kevin Novan* and Yingzi Wang†

Abstract

As the amount of solar and wind generation capacity installed in a region grows, there will increasingly be periods during which a portion of the potential renewable generation will need to be curtailed to maintain the stability of the electric grid. Across markets worldwide, average curtailment rates for wind and solar are generally quite low, often around 3%. However, these low average curtailment rates may overstate how much renewable supply increases as a result of further increases in renewable capacity. Using historical hourly generation and curtailment data from California’s electricity market, we estimate that only 90% of the midday output supplied by new solar and wind capacity goes towards increasing the state’s renewable supply – with the remaining 10% being discarded in the form of increased curtailments.

JEL Codes: Q40; Q51

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1 Introduction

By offsetting electricity production from conventional sources, expansions in renewable capacity can reduce the electricity sector’s fuel, operating, and environmental costs. Understanding the magnitude of these avoided costs plays an important role in guiding a variety of decisions – e.g., where should renewables be targeted and how large should subsidies be?

Quantifying the short-run costs avoided by new renewable capacity requires answering two questions: (1) how large are the costs avoided by each megawatt hour (MWh) supplied, and (2) how many MWhs will the new capacity supply? While the economics literature has focused extensively on the first question, far less attention has been paid to the second question.\footnote{For studies quantifying the costs avoided per MWh supplied, see (Siler-Evans, Azevedo and Morgan, 2012; Cullen, 2013; Kaffine, McBee and Lieskovsky, 2013; Novan, 2015; Holladay and LaRiviere, 2017; Fell and Kaffine, 2018; Callaway, Fowlie and McCormick, 2018; Fell, Kaffine and Novan, 2021).}

Previous studies (e.g., Novan (2015); Gowrisankaran, Reynolds and Samano (2016); Sexton et al. (2021)) typically assume that the quantity supplied by new renewable capacity is determined solely by nature (e.g., wind speeds, solar irradiance). In practice, however, there are periods when the potential renewable generation exceeds what the grid can absorb. Consequently, a portion of the potential output will be curtailed.

Case studies from around the world highlight that average curtailment rates are generally quite low, typically around 3% (Bird, Cochran and Wang, 2014; O’Shaughnessy, Cruce and Xu, 2020). However, these average curtailment rates reflect the share of output curtailed across the entire stock of renewable capacity in a region, not the share curtailed from marginal capacity additions. To provide a better understanding of the short-run benefits of increasing renewable capacity, we estimate how much of the new generation will be curtailed.

Our analysis focuses on California’s electricity market overseen by the California Independent System Operator (CAISO). Using hourly observations of CAISO’s renewable curtailment from June 2018 through September 2022, we identify how marginal increases in utility-scale solar production affect curtailment. Our estimates suggest that, in the short-run, 9.2% of the output generated by an expansion in California’s utility-scale solar capacity...
will be curtailed, far exceeding California’s average solar curtailment rate of 4.3%.

We also find that average curtailment rates understate the curtailment caused by expansions in other renewable technologies. While just 0.4% of the potential wind generation is curtailed during our sample period, we find that only 90% of the midday output from new wind capacity goes towards increasing the state’s renewable supply. The remaining 10% goes towards increasing solar curtailments. Similarly, while there is no mechanism to curtail generation from small-scale solar (e.g. rooftop PV), we present evidence that supplying an additional MWh from small-scale solar causes utility-scale solar curtailment to increase by 0.05 MWh, on average. Ultimately, abstracting from these marginal curtailment impacts will lead to overestimation of the short-run benefits provided by renewable investments.

Our analysis also contributes to the literature illustrating strategies for cost-effectively absorbing intermittent renewables. While curtailments play an important role in minimizing the costs of achieving high levels of renewable production, engineering simulations highlight that a variety of complementary investments (e.g., transmission and storage) and market and rule changes (e.g., reduced minimum generation levels for conventional units) can reduce the amount of clean, low-marginal cost renewable generation that must be curtailed (Frew et al., 2019; Denholm and Mai, 2019; Frew et al., 2021). Complementing these simulation studies, our empirical results illustrate how immediate reductions in curtailment can be achieved by shifting electricity consumption to the midday hours when the energy is being curtailed.

2 Average Curtailment Rates

During 2021, California’s utility-scale solar and wind capacity supplied 25% (48 TWh) of the in-state, utility-scale generation (CEC, 2022). Importantly, the quantity supplied does not reflect the full amount of electricity the solar and wind capacity could have generated. CAISO’s historical curtailment data reveals that, in order to maintain the stability of the grid, potential solar or wind output was curtailed during 50% of the hours during 2021.²

²Curtailments arise for a variety of reasons – e.g., if there is excess renewable supply during low demand periods, local grid congestion, voltage issues. Historical, 5-minute interval curtailment is reported by CAISO: www.caiso.com/informed/Pages/ManagingOversupply.aspx.
While curtailments are common, the average curtailment rates remain low. From July 2018 through September 2022, 4.3% of the potential utility-scale solar output was curtailed.\textsuperscript{3} We define the potential solar output as the sum of the realized and curtailed solar generation. Over the same period, only 0.4% of the potential utility-scale wind generation was curtailed and, as there is no mechanism for CAISO to curtail small-scale solar, none of the potential output from small-scale solar units was curtailed.

While the average curtailment rates are low, Figure 1 highlights that there is substantial variation over time. Importantly, the monthly utility-scale solar curtailment rate has increased across years as solar capacity has grown. This upward trend provides clear evidence that the curtailment rate for marginal increases in solar capacity exceeds the average solar curtailment rate.

3 Marginal Utility-Scale Curtailment Rates

To quantify how much of the potential output from new renewable capacity goes towards increasing curtailment instead of increasing renewable supply, we estimate the following model using daily observations from July 2018 through September 2022:

\[
\text{Curtailment}_d = \beta_1 \cdot \text{Solar}_d^U + \beta_2 \cdot \text{Wind}_d^U + \beta_3 \cdot \text{NetDemand}_d + \theta \cdot X_d + \alpha_m, y + \epsilon_d, \quad (1)
\]

where Curtailment\(_d\) is the curtailed utility-scale solar and wind (MWh) on day \(d\). Solar\(_d^U\) and Wind\(_d^U\) represent California’s daily potential utility-scale solar and wind generation (MWh).\textsuperscript{4} To account for the fact that demand shocks can be correlated with renewable production and curtailment, we control for California’s daily net demand (MWh) – electricity consumption minus small-scale, behind-the-meter generation. Similarly, the vector \(X_d\) includes controls

\textsuperscript{3}The CAISO footprint does not cover the entirety of California. Given that we do not observe non-CAISO curtailments, the curtailment levels we observe may underestimate the amount curtailed in California. However, this is not a major shortcoming. According to EIA-930 data, during 2021, 89% of the California’s utility-scale solar generation, and 96% of the utility-scale wind generation, was supplied by CAISO units, suggesting that we observe the vast majority of California’s curtailment.

\textsuperscript{4}Hourly, utility-scale solar generation, wind generation, and net demand at the state level comes from the EIA-930 dataset.
for the daily net demand and utility-scale solar and wind generation in the surrounding states (AZ, NV, OR). Finally, to control for trends in curtailment and renewable production, we include month-by-year fixed effects.

Column 1 of Table 1 displays the estimates of $\beta_1$, $\beta_2$, and $\beta_3$. Increasing daily potential utility-scale solar by 1 MWh causes daily curtailments to increase by 0.092 MWh, on average. To interpret this coefficient, it is important to note that we do not observe generation or curtailment disaggregated across space. Therefore, we cannot infer how an increase in solar at a specific location would affect curtailment. Instead, the coefficient estimate implies that, if there were small, proportional increases in the installed capacity at California’s utility-scale solar plants, 9.2% of the potential new output would be curtailed.

Recall that, during the sample period, 0.4% of the potential utility-scale wind generation was curtailed. However, that does not imply that increasing potential wind generation by 1 MWh increases renewable supply by 0.996 MWh. Instead, our estimate of $\beta_2$ from column 1 implies that, on average, increasing potential wind generation by 1 MWh increases renewable supply by 0.97 MWh, with the remaining 0.03 MWh being curtailed. Re-estimating Eq. 1 using daily solar curtailment (column 2) or daily wind curtailment (column 3) as separate dependent variables, we find that nearly all of the curtailment caused by an increase in potential wind comes through increased solar curtailment.

Of course much of the wind generation occurs overnight, when there is no solar to curtail. To quantify the marginal curtailment rates during the daytime, we re-estimate Eq. 1 for individual hours of the day. The outcome variable is now the hourly aggregate curtailment and the right-hand-side variables are the hourly potential utility-scale solar and wind generation in California, California’s hourly net demand, and the hourly net demand and renewable generation in the surrounding states. The first two rows of Table 2 display the average change in hourly curtailment caused by a 1 MWh increase in hourly potential utility-scale solar or wind from 10am through the 5pm hours, when the majority of curtailment occurs. From

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5We report Newey-West standard errors to allow for arbitrary serial correlation of up to 5 lags.
10am through the 2pm hour, roughly 10% of each additional MWh of potential utility-scale solar and wind goes towards increasing the aggregate level of curtailment.

4 Curtailment Impacts of Small-Scale Solar

The preceding results highlight how curtailment responds to increases in utility-scale renewable output. During our sample period, however, 35% (77 GWh) of California’s solar generation came from small-scale solar capacity. While there is currently no market mechanism to directly curtail this small-scale output, increases in small-scale solar generation can increase utility-scale curtailment. The estimates of \( \beta_3 \) from the bottom rows of Tables 1 and 2 provide evidence that this is occurring. Recall, the net demand is equal to consumption minus small-scale, behind-the-meter generation. The fact that the estimates of \( \beta_3 \) are all negative therefore suggests that increasing small-scale solar output increases utility-scale curtailment. However, most of the variation used to identify \( \beta_3 \) from Eq. 1 stems from fluctuations in consumption, not small-scale solar generation. Therefore, the estimates may misstate the impact of small-scale solar generation on curtailment.

Ideally we could directly estimate the impact of daily (hourly) small-scale solar generation on curtailment. However, there are two impediments. First, there is no daily (hourly) time series of small-scale solar output. Therefore, we first estimate an hourly time series of California’s small-scale solar generation. To do so we model the unobserved hourly capacity factor for California’s small-scale solar (i.e. the hourly small-scale solar generation divided by the installed small-scale solar capacity) as a function of the observed hourly utility-scale solar capacity factor. Intuitively, on a sunny day when California’s utility-scale solar generation is high, we expect production from the state’s small-scale solar capacity to be high as well. To account for technology-driven productivity differences (e.g., utility-scale solar units typically rotate to track the sun while small-scale units are often fixed), we allow the relationship between utility- and small-scale capacity factors to vary flexibly across hours of the day and continuously throughout the year. To estimate the parameters of our model, we use EIA’s

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\(^6\)Estimates of monthly small-scale solar generation comes from the US EIA’s Electric Power Monthly.
estimates of California’s monthly small-scale solar output and capacity. Our estimation procedure is described in detail in an appendix.

Even with estimates of hourly small-scale solar output, there is a second issue to confront – utility- and small-scale solar output is highly correlated, preventing us from simultaneously, and precisely, estimating their individual impacts on curtailment. Instead, we augment Eq. 1 and estimate the following model:

\[
\text{Curtailment}_d = \beta_1 \cdot \text{Solar}_T^d + \beta_2 \cdot \text{Wind}_d + \beta_3 \cdot \text{Consumption}_d + \theta \cdot X_d + \alpha_m, y + \varepsilon_d, \tag{2}
\]

where \(\text{Solar}_T^d\) represents the daily total potential solar generation – utility-scale potential solar generation plus the estimated small-scale solar generation. With small-scale solar production included in \(\text{Solar}_T^d\), we no longer control for California’s net demand. Instead, we control for \(\text{Consumption}_d\), the observed daily net demand in California plus the predicted daily small-scale solar production. The remaining variables are unchanged from Eq. 1.

Given the high correlation between utility- and small-scale solar, \(\beta_1\) from Eq. 2 effectively represents the weighted average of the marginal curtailment rate for utility-scale solar, which we found to be 9.2% (Table 1), and the marginal curtailment rate for small-scale solar, which is what we are interested in uncovering. Over the sample period, 65% of the total potential solar production, and thus roughly 65% of the variation in total daily solar production, came from utility-scale units and 35% came from small-scale units. Hypothetically, if an increase in small-scale solar caused no change in curtailment, then we would expect the average change in curtailment in response to a 1 MWh increase in total potential solar to be \((0.65) \cdot (0.092) + (0.35) \cdot (0) = 0.06\) MWh. However, column 1 of Table 3 reveals that curtailment increases by 0.078 MWh in response to a 1 MWh increase in total potential solar. This point estimate suggests that, on average, 5.2% of an additional MWh of small-scale solar production is curtailed in the form of reduced supply from utility-scale units.\(^7\)

\(^7\)Given that there is some unknown noise in our estimates of the hourly small-scale solar output, the estimate of \(\beta_1\) from Eq. 2 likely suffers from attenuation bias. Consequently, we view the 5.2% marginal curtailment impact as a lower bound.
To explore how the curtailment impacts differ throughout the day, we re-estimate the model specified by Eq. 2 separately for each hour of the day. Figure 2 displays the estimates of the average change in hourly curtailment in response to a 1 MWh increase in total potential solar, utility-scale wind, and consumption. Again, the coefficients on total solar are only slightly attenuated towards zero compared to the corresponding estimates of the impact of utility-scale potential solar from Table 2, suggesting again that increases in small-scale solar throughout the day increase utility-scale curtailment.

5 Discussion and Conclusions

Average curtailment rates for solar and wind are typically quite low. In California, nearly 98% of the total potential solar and wind generation from July 2018 through September 2022 was ultimately supplied to the grid. However, our results reveal this does not mean that 98% of the potential output from new renewable capacity additions will go towards increasing renewable supply. Instead, the figure is meaningfully lower for two reasons.

First, the curtailment rate for marginal increases in utility-scale solar exceeds the average curtailment rate. While the average curtailment rate for California’s utility-scale solar was below 5% during our study period, we estimate that, absent meaningful infrastructure or market changes, approximately 10% of the potential output from marginal increases in utility-scale solar capacity will go towards increasing curtailment.

Second, the 0.4% average curtailment rate for utility-scale wind, and the zero curtailment rate for small-scale solar, don’t reflect how utility-scale solar curtailments are affected. In particular, we find that supplying an additional MWh of wind generation during the midday hours reduces utility-scale solar supply by 0.1 MWh. Similarly, a 1 MWh increase in small-scale solar only increases the total renewable supply by 0.95 MWh – with the remaining 0.05 MWh being curtailed at utility-scale solar units.

When evaluating the benefits provided by increases in renewable capacity, it is important to account for these marginal curtailment rates. For example, empirical studies often seek to quantify the emissions avoided by renewable investments (e.g., Novan (2015); Callaway,
Fowlie and McCormick (2018); Gowrisankaran, Reynolds and Samano (2016); Sexton et al. (2021)). In the case of California’s market, assuming that 100% of the potential output from new solar and wind capacity will go towards expanding the state’s renewable production will result in meaningful overestimation of the short-run emissions avoided.

The results also have implications for how households with rooftop solar are compensated. Under California’s original net energy metering (NEM) policy adopted in the 1990s, households installing rooftop solar units were paid the retail price of electricity for each kWh they supplied back to the grid. Previous studies highlighted that, because the marginal social cost of producing an additional kWh is typically far lower than the retail price paid by California consumers (Borenstein and Bushnell, 2022), this approach over-subsidized households for their solar generation (Borenstein, 2017; Vaishnav, Horner and Azevedo, 2017). Our findings suggest that the overcompensation for rooftop solar was even more pronounced than originally thought given that only 95% of an increase in small-scale solar goes towards increasing the state’s renewable supply. This finding provides further support for ongoing efforts to reduce how much California households are compensated for rooftop solar output.

Finally, our results also illustrate the role that load shifting can play in reducing curtailment. Figure 2 highlights that increasing consumption between 8am and 3pm by 1 MWh reduces curtailment by roughly 0.04 MWh. In contrast, curtailment is unaffected by consumption changes during other hours. Consequently, curtailments would be reduced by roughly 0.04 MWh for each MWh of demand shifted from the non-midday hours to the middle of the day. While California’s large investor-owned utilities recently transitioned to default time-of-use pricing, the vast majority of consumers continue to pay the same price for electricity across all hours outside of the 4pm to 9pm peak price period. Our results suggest that, by providing stronger price signals for consumers to shift consumption specifically to the midday hours, meaningful reductions in curtailment can be achieved.
References


Figure 1: The figure displays the monthly curtailment rate for utility-scale solar and wind in California. The monthly curtailment rates are equal to the total monthly curtailment in the CAISO market of utility-scale solar (wind) divided by the monthly potential utility-scale solar (wind) generation in California, where the potential generation is equal to the generation supplied plus curtailed output. The historical curtailment data is published by CAISO. The total utility-scale solar and wind generation comes from the EIA-930 dataset.
Figure 2: The figure displays the point estimates of how the hourly level of CAISO curtailment (MWh) changes, on average, in response to a 1 MWh increase in the hourly potential utility-scale solar generation, a 1 MWh increase in the hourly potential utility-scale wind generation, and a 1 MWh increase in the hourly total electricity consumed. The point estimates all stem from estimating Eq. 2 for each individual hour-of-day using observations spanning July 2018 through September 2022.
Table 1: Average daily utility-scale marginal curtailment rates

<table>
<thead>
<tr>
<th></th>
<th>Total daily curtailment</th>
<th>Utility-scale solar curtailment</th>
<th>Utility-scale wind curtailment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Potential utility-scale solar (MWh)</td>
<td>0.092**</td>
<td>0.092**</td>
<td>0.00</td>
</tr>
<tr>
<td></td>
<td>(0.016)</td>
<td>(0.015)</td>
<td>(0.001)</td>
</tr>
<tr>
<td>Potential utility-scale wind (MWh)</td>
<td>0.029**</td>
<td>0.023**</td>
<td>0.005**</td>
</tr>
<tr>
<td></td>
<td>(0.008)</td>
<td>(0.008)</td>
<td>(0.001)</td>
</tr>
<tr>
<td>California net demand (MWh)</td>
<td>-0.015**</td>
<td>-0.015**</td>
<td>-0.00</td>
</tr>
<tr>
<td></td>
<td>(0.004)</td>
<td>(0.004)</td>
<td>(0.000)</td>
</tr>
<tr>
<td>N</td>
<td>1498</td>
<td>1498</td>
<td>1498</td>
</tr>
<tr>
<td>R²</td>
<td>0.22</td>
<td>0.22</td>
<td>0.13</td>
</tr>
</tbody>
</table>

Each column displays the estimates of $\beta_1$, $\beta_2$, and $\beta_3$ from Eq. 1. These parameters represent how the daily total curtailment (column 1), the daily utility-scale solar curtailment (column 2), or the daily utility-scale wind curtailment (column 3) changes in response to a 1 MWh increase in daily potential utility-scale solar generation, a 1 MWh increase in daily potential utility-scale wind generation, and a 1 MWh increase in the daily net demand for electricity in California. Each model also include controls for the daily solar generation, daily wind generation, and daily net demand in the surrounding western states. In addition, each model includes month-by-year fixed effects. We report Newey-west standard errors, in parentheses, to allow for arbitrary serial correlation of up to 5 lags. * = significant at the 5% level; ** = significant at the 1% level.
Table 2: Average hourly utility-scale marginal curtailment rates

<table>
<thead>
<tr>
<th></th>
<th>10am</th>
<th>11am</th>
<th>12pm</th>
<th>1pm</th>
<th>2pm</th>
<th>3pm</th>
<th>4pm</th>
<th>5pm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Potential utility-scale solar (MWh)</td>
<td>0.072**</td>
<td>0.106**</td>
<td>0.102**</td>
<td>0.113**</td>
<td>0.119**</td>
<td>0.125**</td>
<td>0.127**</td>
<td>0.082**</td>
</tr>
<tr>
<td>Potential utility-scale wind (MWh)</td>
<td>0.112**</td>
<td>0.119**</td>
<td>0.122**</td>
<td>0.129**</td>
<td>0.101**</td>
<td>0.066**</td>
<td>0.025*</td>
<td>0.007</td>
</tr>
<tr>
<td>California net demand (MWh)</td>
<td>-0.053**</td>
<td>-0.046*</td>
<td>-0.040**</td>
<td>-0.027**</td>
<td>-0.024**</td>
<td>-0.013**</td>
<td>-0.010**</td>
<td>-0.005*</td>
</tr>
</tbody>
</table>

Each column displays the estimates of $\beta_1$, $\beta_2$, and $\beta_3$ found by estimating Eq. 1 separately for individual hours of the day. For each model, the dependent variable is the aggregate hourly curtailment (MWh) of utility-scale solar and wind. The coefficients reflect how the hourly curtailment changes in response to a 1 MWh increase in hourly potential utility-scale solar generation, a 1 MWh increase in hourly potential utility-scale wind generation, and a 1 MWh increase in the hourly net demand for electricity in California. Each model also include controls for the hourly solar generation, hourly wind generation, and hourly net demand in the surrounding western states. In addition, each model includes month-by-year fixed effects. We report Newey-west standard errors, in parentheses, to allow for arbitrary serial correlation of up to 5 lags. * = significant at the 5% level; ** = significant at the 1% level.

N 1553 1553 1553 1553 1553 1553 1553 1553 1553
R² 0.23 0.26 0.26 0.25 0.23 0.23 0.23 0.23 0.17
Table 3: Average daily marginal curtailment rate for total solar

<table>
<thead>
<tr>
<th>Dependent Variable (MWh)</th>
<th>Total daily curtailment</th>
<th>Utility-scale solar curtailment</th>
<th>Utility-scale wind curtailment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Potential total solar (MWh)</td>
<td>0.078**</td>
<td>0.078**</td>
<td>0.00</td>
</tr>
<tr>
<td></td>
<td>(0.011)</td>
<td>(0.010)</td>
<td>(0.001)</td>
</tr>
<tr>
<td>Potential utility-scale wind (MWh)</td>
<td>0.028**</td>
<td>0.023**</td>
<td>0.005**</td>
</tr>
<tr>
<td></td>
<td>(0.008)</td>
<td>(0.008)</td>
<td>(0.001)</td>
</tr>
<tr>
<td>Total California consumption (MWh)</td>
<td>-0.015**</td>
<td>-0.015**</td>
<td>-0.00</td>
</tr>
<tr>
<td></td>
<td>(0.004)</td>
<td>(0.004)</td>
<td>(0.000)</td>
</tr>
<tr>
<td>N</td>
<td>1498</td>
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<td>0.13</td>
</tr>
</tbody>
</table>

Each column displays the estimates of $\beta_1$, $\beta_2$, and $\beta_3$ from Eq. 2. These parameters represent how the daily total curtailment (column 1), the daily utility-scale solar curtailment (column 2), or the daily utility-scale wind curtailment (column 3) changes in response to a 1 MWh increase in the total daily potential solar generation (utility-scale plus small-scale solar), a 1 MWh increase in daily potential utility-scale wind generation, and a 1 MWh increase in daily electricity consumption in California. Each model also include controls for the daily solar generation, daily wind generation, and daily net demand in the surrounding western states. In addition, each model includes month-by-year fixed effects. We report Newey-west standard errors, in parentheses, to allow for arbitrary serial correlation of up to 5 lags. * = significant at the 5% level; ** = significant at the 1% level.
Online Appendix

Small-Scale Solar Estimates

To estimate how curtailments are affected by marginal changes in the total amount of potential solar generation – i.e. the sum of utility-scale and small-scale solar potential – we need to first estimate the hourly level of small-scale solar generation. To do so, we model the unobserved small-scale solar capacity factor as a function of the utility-scale solar capacity factors, which we are able to calculate. In addition to the utility-scale solar generation data (from EIA-930), and the utility-scale solar curtailment data (from CAISO), we also utilize estimates of the monthly aggregate small-scale solar generation in California, provided by the US EIA’s Electric Power Monthly reports. In addition, the EIA report record the monthly installed utility-scale and small-scale solar capacity.

Using the observed, monthly potential utility-scale solar generation (the observed supply plus curtailments) and the monthly installed utility-scale solar capacity, we calculate the monthly utility-scale solar capacity factor for California. The capacity factor is equal to the ratio of the total potential generation during the month (measured in MWh) divided by the product of the installed capacity (measured in MW) and the number of hours during the month. Similarly, we calculate the monthly small-scale solar capacity factors for California. Figure A1 displays the monthly potential capacity factors for utility-scale and small-scale solar in California from July 2018 through September 2022.

Figure A1 highlights that California’s utility-scale capacity factors are uniformly higher than the small-scale capacity factors. This difference arises for a couple of reasons. California’s utility-scale solar plants are primarily sited in inland, exposed areas with higher average levels of solar irradiance than the small-scale solar units which are located primarily in population centers. Despite the differences in location, however, Figure 3 demonstrates that, at the monthly level, large-scale capacity factors are highly correlated with the small-scale capacity factors. We ultimately exploit this relationship to predict the hourly small-scale solar capacity factors.
Importantly, however, Figure A1 also highlights that the difference between the utility-scale and small-scale capacity factors is not constant, but rather, varies across seasons. These differences are not simply due to differences in the location. Instead, they arise in large part due to technological differences. The angle at which the sun hits a solar panel is one of the key determinants of the panel’s efficiency. Solar panels will produce more efficiently when the sun is directly perpendicular to them. While utility-scale solar arrays are typically able to rotate on one or two axes to ensure they remain oriented perpendicular to the sun throughout the day and across seasons, small-scale ground-mounted or rooftop units are almost exclusively fixed tilt installations that are unable to rotate with the sun.

Ultimately, our objective is to estimate the unobserved small-scale solar capacity factors $CF_{h,d}^S$ for each hour $h$ of each day $d$ using the observed hourly utility-scale solar capacity factors $CF_{h,d}^U$. Accordingly, we must account for not only the average gap between the capacity factors, but also the systematic time-of-day and seasonal differences that arise due to the technological differences. To do so, we first assume that the hourly small-scale capacity factor can be flexibly modeled as a function of the hourly utility-scale capacity factor using the following specification:

$$CF_{h,d}^S = CF_{h,d}^U \cdot (\alpha_1 + \alpha_2 \cdot A_{h,d}) + \varepsilon_{h,d},$$

where $A_{h,d}$ is the elevation angle of the sun, which measures the angular height of the sun in the sky measured from the horizontal. The elevation angle varies across hours of the day, reaching its highest levels midday when the sun is directly overhead. In addition, the elevation angle varies across seasons, reaching its highest levels in California during the summer. We use the elevation angle for a central location in Southern California (Barstow, CA). Figure A2 displays how $A_{h,d}$ varies across hours of a single day during different seasons. On Dec. 1st, the midday elevation angle of the sun peaks around 30°. This is similar to the elevation angle that is observed around 8am and 4pm on June 1st. Our modeling approach assumes that the ratio of the small- to utility-scale solar capacity factor observed at noon on
Dec. 1st is the same as the ratio observed on June 1st at 8am and 4pm. Importantly, our approach allows the levels of the small- and utility-scale capacity factors to differ without constraints across these hours and days. We simply assume that if the utility-scale capacity factor is relatively high during an hour, then the small-scale capacity factor will also be relatively high (and vice versa).

Given that we do not observe the hourly small-scale capacity factors, we cannot directly estimate the parameters of interest ($\alpha_1, \alpha_2$) from Eq. A1. Instead, we can aggregate Eq. A1 up to the monthly level to model the observed monthly small-scale solar capacity factors $CF^{S_m}$ as a function of the hourly utility-scale capacity factors:

$$CF^{S_m} = \sum_{h,d} CF^{S}_{h,d}$$

where $H_m$ is the number of hours during month $m$. Note, we observe the installed utility-scale solar capacity at the beginning of each month, not during each day. To calculate $CF^{U}_{h,d}$, we need to assume a given level for the daily utility-scale solar capacity. Rather than assuming that the installed utility-scale capacity is growing discontinuously at the beginning of each month, we assume that the capacity grows linearly from the beginning of one month to the beginning of the next month. Under this assumption, the hourly utility-scale solar capacity factor is calculated using the following equation:

$$CF^{U}_{h,d} = \frac{S^{U}_{h,d}}{C^{U}_m + (C^{U}_m - C^{U}_{m+1}) \cdot (D_d/N_m)}$$

where $S^{U}_{h,d}$ is the utility-scale potential generation during hour $h$ of day $d$. $C^{U}_m$ is the utility-scale solar capacity at the beginning of month $m$ and $C^{U}_{m+1}$ is the capacity at the beginning of the next month. $D_d$ is the number of the date of day $d$, and $N_m$ is the total number of days in the same month.

Using the estimates of California’s hourly utility-scale solar capacity factors from Eq. A3, the hourly elevation angle of the sun in Southern California ($A_{h,d}$), and the EIA reported
estimates of California’s monthly small-scale solar capacity factors ($CF_{sm}^S$), we estimate the parameters of interest from Eq. A2 ($\alpha_1, \alpha_2$) over the 51 months spanning July 2018 through September 2022 using ordinary least squares. Note, we do not include a constant in the regression. A non-zero constant would effectively imply that, on a hypothetical day when the utility-scale solar capacity factor is zero, the small-scale solar capacity factors could be positive. The coefficient estimates and model fit are summarized in Table 5. Note, the simple linear model explains 98% of the variation in the monthly small-scale capacity factors. The positive estimate of $\alpha_2$ implies that, when the elevation angle of the sun falls (e.g., late in the afternoon or during the non-summer months), the gap between the productivity of the utility-scale and small-scale solar units becomes relatively larger, as is expected given the ability of the utility-scale units to rotate with the angle of the sun.

Plugging in the estimates of $\alpha_1$ and $\alpha_2$ into Eq. A1, we calculate the hourly small-scale solar capacity factors for California from July 2018 through September 2022. Multiplying by the installed small-scale solar capacity, again assuming that the installed capacity increases linearly between the first day of each month, we are able to produce estimates of the hourly generation ($S_{h,d}^S$) from California’s small-scale solar capacity.

With the estimates of the hourly small-scale solar output, we generate two new variables. First, the total potential solar generation for California during hour $h$ of day $d$ ($S_{h,d}^T$), which is simply the sum of the potential utility-scale solar generation and the estimated small-scale solar generation: $S_{h,d}^T = S_{h,d}^U + S_{h,d}^S$. Second, we define the total electricity consumption (Consumption$_{h,d}$) during hour $h$ of day $d$ as the sum of the observed hourly net demand (NetDemand$_{h,d}$) in California and the estimated small-scale solar generation ($S_{h,d}^S$).
Appendix Figures and Table

Figure A1: The figure displays California’s monthly potential utility-scale solar capacity factors and the monthly small-scale solar capacity factors. The utility-scale solar capacity factors are calculated by dividing the average hourly potential utility-scale solar in CA by the monthly installed utility-scale solar capacity. The monthly small-scale solar capacity-factor is calculated by dividing the monthly small-scale solar generation in CA by the product of the MW of installed small-scale solar capacity and the number of hours during the month. The monthly small-scale solar generation and the installed solar capacity are available from the EIA’s Electric Power Monthly reports.
Figure A2: The figure displays the hourly average elevation angle of the sun from 7am through 7pm at Barstow, CA on four different days of the year. A negative value of the elevation angle represents periods of the day when the sun has not yet risen or has already set. An elevation angle of 90° would represent the sun being directly above (perpendicular) to the earth’s surface.

Table A1: Coefficient estimates from Eq. A2

<table>
<thead>
<tr>
<th>Dependent Variable: monthly small-scale solar capacity factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\alpha_1$</td>
</tr>
<tr>
<td>$\alpha_1$</td>
</tr>
<tr>
<td>N</td>
</tr>
<tr>
<td>$R^2$</td>
</tr>
</tbody>
</table>

The table displays the point estimates of the two parameters from the model specified by Eq. A2. The model is estimated using monthly small-scale solar capacity factor estimates from the EIA as the dependent variable. The data spans July 2018 through September 2022. The independent variables are the monthly potential utility-scale solar capacity factors and the monthly potential utility-scale solar capacity factors weighted by the hourly elevation angles. We report Newey-west standard errors, in parentheses, to allow for arbitrary serial correlation of up to 5 lags. * = significant at the 5% level; ** = significant at the 1% level.