Was it worthwhile? Where have the benefits of rooftop solar photovoltaic generation exceeded the cost?

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Abstract

We estimate the lifetime magnitude and distribution of the private and public benefits and costs of currently installed distributed solar PV systems. Using data for recently-installed systems, we estimate the balance of benefits and costs associated with installing a non-utility solar PV system today. We also study the geographical distribution of the various subsidies that are made available to owners of rooftop solar PV systems, and compare it to distributions of population and income. We find that, after accounting for federal subsidies and local rebates and assuming a discount rate of 7%, the private benefits of new installations will exceed private costs only in states characterized by abundant sunshine (California, Texas and Nevada) or states with high electricity prices (New York), and only if customers can sell excess power to the electric grid at the retail price. Public benefits from reduced air pollution and climate change impact exceed the costs of the various subsidies offered system owners for less than 10% of the systems installed, even assuming a 2% discount rate. Subsidies flowed disproportionately to counties with higher median incomes in 2006. In 2014, the distribution of subsidies was closer to that of population income, but subsidies still flow disproportionately to the better-off. The total, upfront, subsidy per kilowatt of installed capacity has fallen from $5200 in 2006 to $1400 in 2014, but the absolute magnitude of subsidy has soared as installed capacity has grown explosively. We see considerable differences in the balance of costs and benefits even within states, indicating that local factors such as system price and solar resource are important, and that policies (e.g., net metering) could be made more efficient by taking local conditions into account.

1. INTRODUCTION

The United States currently emits about 6.5 billion metric tons of CO_2e annually, an increase of 3.4% over 1990 levels,[1] with 30% of that total generated by the U.S. electricity sector. Driven largely by the displacement of coal by natural gas and—to a lesser extent—by renewables, emissions from electricity production are now at their lowest level since 1993.[2] However, achieving the deep decarbonization necessary to reach climate goals will require further replacement of fossil fuels by zero-emission sources such as renewables in the electricity sector.[3]

Solar photovoltaic (PV) will likely be an important part of this altered fuel mix, as evidenced by its 60% compound annual growth rate over the past decade.[4] While utility-scale PV capacity additions overtook distributed PV installations for the first time in 2012,[5] the latter category continues to see robust growth, with 2.5 GW added in 2015 and 3.4 GW added in 2016.[6]

Three factors have driven this capacity growth: an impressive fall in system prices from about \$12/W_{DC}[*] (in 2015 dollars) in 1998 to \$4/W_{DC} for residential systems in 2015,[7] policy incentives for system installation at the federal, state, and local levels, and net metering programs offered by some utilities that allow solar PV customers to sell excess electricity back to the grid.

At the federal level, both direct technology investment and subsidies have been used to reduce the up-front cost of distributed PV. The Department of Energy's SunShot program funds research, development, demonstration, and deployment projects aimed at bringing per-kilowatt installation costs down.[9] At the same time, a 30% federal investment tax credit (ITC) originally enacted in 2005, and extended several times since, subsidizes PV system installation.[10]

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[*] These prices are in dollars per DC watt in Lawrence Berkeley National Laboratory's (LBNL) *Tracking the Sun* report.[7] To convert prices to dollars per AC watt, multiply by the DC to AC ratio, which is approximately 1.15 for residential systems.[8]

At the state and local levels, a variety of rebates incentivize solar PV capacity additions. Examples include the Merced irrigation district rebate of \$1.50 per W_{DC} of capacity in 2014,[11] when the average price of a residential system in California was \$4.6 per W_{DC},[7] and \$113 million in rebates distributed by the Pennsylvania Sunshine program between May 2009 and November 2013. The latter program spurred \$560 million in private investment, and as of 2013 approximately 50% of the state's 200 MW in solar capacity utilized the rebate.[12]

Finally, net metering policies improve the economics of distributed solar PV systems by allowing their owners to sell unused electricity back to the grid. The strong impact of rate design for distributed generation customers can be seen in the rapid exit of rooftop solar providers from Nevada after that state eliminated net metering at the beginning of 2016. The price net metering customers are paid—and the structure of the rest of the tariff, such as the inclusion of demand charges—continues to be the subject of contention among utilities, customers, and public utility commissions. Of particular concern is potential cross-subsidization of net metering customers by other customers when the former are paid at the retail price.[13] Valuing the net benefit of solar PV is perhaps the critical issue in these debates.

Our analysis extends previous estimates of the various costs and benefits of solar PV. For example, Hagerman *et al.*[14] find that unsubsidized rooftop solar PV does not achieve socket parity anywhere in the U.S., except Hawaii. Wiser *et al.*[15] find that policies to promote solar PV (including by utilities) will produce climate change and other environmental benefits of over \$400 billion between 2015 and 2050.

In this paper, we estimate both the magnitude and distribution of the benefits and costs of currently installed distributed solar PV systems over the course of their lifetimes. Using data for recently-installed systems, we estimate the balance of benefits and costs associated with installing a non-utility solar PV system today. We perform this analysis for each system in a dataset that includes the majority of non-utility solar PV systems currently installed in the U.S., producing a fine-grained picture of the geographical distribution of benefits and costs across the country. We recognize the diversity and dynamism of policies across the country, and our analysis seeks to place reasonable bounds on the range of outcomes by considering policies that are generous to PV adopters and those that are niggardly. Finally, we study the geographical distribution of the various subsidies available to owners of rooftop solar PV systems and compare it to distributions of population and income. Combined with our analysis on costs and benefits, this allows us to comment not only on whether subsidies were *effective* in incentivizing the adoption of solar and on their economic *efficiency*, but also on whether they were *equitable*. Because our dataset spans nearly two decades (from 1999 to 2015), our analysis shows how subsidies and their distribution have evolved.

2. PROBLEM STATEMENT

In this analysis, we address three questions.

1. What are the total life-time costs and benefits – both private and public – of rooftop solar PV systems installed to-date in the U.S.? That is, have historic solar PV installations, in aggregate, paid off?
2. What are the annualized per-kilowatt costs and benefits of solar PV systems installed across the U.S. between 2011 and 2015? That is, under what circumstances does installation of a current system pay off?
3. How are the subsidies – rebates, grants, and federal investment tax credits – distributed among counties with different median incomes? That is, have subsidies for solar PV been equitable?

We report the results for the U.S. and at the level of states and counties.

3. DATA

We answer the first two questions in the problem statement for each system in a dataset assembled by the Lawrence Berkeley National Laboratory (LBNL) that includes the majority of the installed base of distributed solar PV systems in the U.S.[16]

3.1 Currently installed systems

The LBNL dataset consists of more than 800,000 systems, representing over 9.5 GW of capacity installed between 1999 and 2015. For comparison, the Energy Information Administration (EIA) estimates that a total of 9.8 GW of distributed solar PV capacity has been installed in the U.S. as of the end of 2015.[17] After removing 260,000 systems in the dataset without information on installation price, rebates, or location, our final dataset includes 540,000 systems with a total installed capacity of 6 GW. In the Supplementary Information (SI) Section S1.1, we show examples of system capacity distributions in the data set. We also refer the reader to LBNL's *Tracking the Sun VIII*[7] report for more details.

3.2 Installed price of systems

The LBNL dataset lists the system installation price before any rebates or incentives are applied. This price may represent the price reported by the installer, customer, or (in the case of third-party owned systems) other incentive applicant. In some cases, it may represent the appraised rather than the reported value of the system. We assume that this value is reported in nominal dollars of the year of installation and convert it to 2015 dollars using the gross private domestic investment implicit price deflator.[18] In the Supplementary Information (SI) Section S1.1, we provide some examples of the price distributions.

3.3 Rebates or grants

The data set also includes the level of grant or rebate associated with the installation of each system. Nearly 400,000 of the 540,000 systems in our reduced dataset received a grant or rebate, with a median value of $1,600 (2015); the rest received no rebate or grant.

3.4 Federal investment tax credit

We assume that systems installed in or after 2006 have taken advantage of the federal investment tax credit (ITC) of 30 percent.[10] This credit is applied to the full installation cost of the system, net of any rebates as described above. We calculate the ITC for each system and inflate it to 2015 dollars.

3.5 Power generation

We estimate the hourly electricity generation at each location for which insolation data is available (approximately 1,000 locations) from the National Renewable Energy Laboratory's (NREL) Typical Meteorological Year (TMY3),[19] using a method outlined by Lorenzo.[20] We identify the TMY3 site geographically closest to each system and calculate the power output of the system for each hour of a typical year. For non-residential systems, we assume that all the electricity generated offsets consumption. For residential systems, we compare the calculated hourly power generation of each system to the residential hourly load profiles[21] for that location as compiled by the U.S. Department of Energy's Office of Energy Efficiency & Renewable Energy (EERE). When the load exceeds or is equal to the generation, we assume that all the generation offsets consumption. In all other cases, we assume that the excess power is sold back to the grid. In the Supplementary Information (SI) Section S1.2, we provide a map of annual generation of a 1kW system.

3.6 Valuing electricity produced

As described above, electricity generated by the PV system either offsets consumption or is sold back to the grid. Each of these cases is valued differently. Offset consumption for each system is summed over each year and multiplied by the average retail price for that year in the appropriate U.S. state. We use the residential retail price for residential systems and the commercial retail price for all other systems from the Energy Information Administration's (EIA) annual state average retail electricity prices for each year from 1990 to 2015.[22]

The electricity sold back to the grid is valued using two alternative prices, which function as bounding cases for our analysis: (i) the appropriate retail price, and (ii) the hourly state-average locational marginal price (LMP) for 2015. The former closely approximates a net metering policy, in effect in several areas in the U.S. (e.g., Los Angeles[23]), that credits the applied power to the customer's bill at the retail rate and allows the customers to roll over such credit over a 12-month period, and this valuation scenario arguably represents a "best case" from the point of view of the customer. We treat the case in which the customer only receives the LMP as a "worst case," while recognizing that – from the point of view of the utility – electricity generated by small, distributed power sources might be valued at or below the LMP using an avoided cost calculation or when accounting for the costs of feeding distributed generation back into the grid.

Hourly, real-time market LMP data for year 2015 for representative aggregate pricing nodes (APNs) in each state were downloaded from the ISO/RTO data portals. For states not in an electricity market, we use gateway or generation nodes reported by a neighboring ISO. For additional detail on the LMP data used, see Horner (2016), Section 4.3.2 and Table 4.4.[24]

We recognize also that distributed electricity sources can create value for utilities – for example, by allowing investments in transmission and distribution infrastructure or new generation to be avoided or deferred – that is in addition to the LMP. This value depends on the location and on the penetration of renewables, and is the subject of much analysis and debate.[25,26] We do not seek to resolve the debate here, and we ignore these effects. Our contention is that these two approaches set reasonable bounds on the value of the surplus electricity produced.

We treat the value of the electricity generated as an estimate of the private benefit that the system produces each year, since this value accrues to the individual who (or entity that) installs the system.

3.7 Valuing health and environmental benefits

We estimate the marginal benefits as avoided damages from the reduction in the emissions of CO_2, SO_2, NO_X, and $PM_{2.5}$ for each kilowatt-hour (kWh) of fossil fuel electricity production displaced by the solar PV installation. We first calculate avoided emissions by a marginal displacement of electricity sourced from the bulk power system during each hour of the day for each season for each year from 2006 to 2014 in each eGrid region using techniques outlined in Siler-Evans *et al.*,[27,28] based on data from the Central Emissions Monitoring System (CEMS).

To translate emissions reductions to damage reductions, we use two integrated air quality models: AP2 – the updated version of the Air Pollution Emission Experiments and Policy analysis (APEEP) model,[29,30] and the EASIUR model.[31,32] Using two models allows us to test the robustness of our results. We find that the results are not very sensitive to the choice of air quality model, and so we report results based on the EASIUR model but note that they would be qualitatively identical if the AP2 model were used instead (see Section S2.1 of the SI).

As described above, we use TMY3 data to calculate the hourly power generation – and, therefore, marginal damages avoided – by a 1 kW system in each location. These hourly estimates are summed to arrive at the annual damages avoided by a 1kW system at each TMY3 location. Damages are split into air quality damages (the sum of damages avoided through the reduced emissions of SO_2, NO_X, and $PM_{2.5}$), and greenhouse gas damages (from the avoided emissions of CO_2, valued at \$40 per metric ton CO_2).[33]

Each system in the LBNL database is then mapped to its nearest TMY3 location, and the damages that the generation from that system would have avoided in a particular year calculated by multiplying estimates of avoided damages for a 1kW system by system capacity.

For the years 1999-2005, we assume that the avoided damages can be approximated by the 2006 damage estimates, and that the 2015-2034 damages are approximated by 2014 estimates. We assume that emissions from solar PV generation are negligible, and neglect non-combustion emissions from fossil electricity production. We discuss and justify both assumptions in Section S1.4 of the SI.

3.8 Valuing the cross subsidy

Certain net metering policies might allow residential customers to sell excess generation to the grid at the retail price during any hour of the day. It could be argued that an ordinary generator who supplies electricity to the grid would only receive the locational marginal price (LMP), and that the LMP therefore represents the true market value of the electricity produced. To the extent that net metering policies are financed by spreading their cost over the entire rate base, they constitute a transfer of resources to those households that install rooftop PV systems from the households that do not. The difference between the retail and locational marginal prices thus arguably constitutes a cross subsidy. We assess distributional inequities by comparing the distribution by income of the value of the cross subsidy (the sum of hourly net generation multiplied by the difference in retail and marginal prices) to the distribution of population by income. We obtain population[34] and county median income data[35] from the U.S. Census Bureau. This subsidy is available to system owners for each year that the system operates, and we calculate it as the present value, expressed in 2015 dollars, of a series of discounted annual cash flows that stretches from whenever the system was installed to the end of its life.

4. METHODS

We answer the three questions posed in Section 2 as follows. Details of the calculations performed, including the equations used, are available in Section S2 of the SI.

4.1 Life-time costs and benefits of currently installed systems

We define the costs and benefits as below.

Private cost = System price – Rebates or grants – Federal investment tax credits (as described in Sections 3.2, 3.3 and 3.4)

Private benefit = Present value of the electricity generated each year that the system was or is in operation (as described in Section 3.6)

Public cost = Rebates or grants + Federal investment tax credits + Price subsidy (as described in Sections 3.3, 3.4, and 3.8)

Public benefit = Present value of the monetized benefit associated with the reduction in CO_2, SO_2, NO_x, and $PM_{2.5}$ (as described in Section 3.7)

To calculate the present values of annual electricity sales and health and environmental benefits, we convert past values to 2015 dollars by using the appropriate price deflator (see Section 3.2), and discount future values using alternative discount rates of 2 and 7 percent per year. We describe our reasons for using these discount rates in Section S1.3 of the SI. We can then calculate the private *net* benefit as the difference between private benefits and costs, and the public *net* benefit as the difference between public benefits and costs. We calculate each of these values for each individual system, and then aggregate them at the state and county levels.

4.2 Annualized per-kilowatt costs and benefits of recently installed solar PV systems

Whereas our first research question sought to quantify the lifetime benefits and costs of currently installed systems, the second question seeks to estimate the *current* balance of costs and benefits of PV systems at different locations in the continental U.S. To answer this question, we only consider systems that were installed in the five years from 2011-15. Over 90% of the 540,000 systems in our initial dataset, and 5.6GW of the total 6GW of installed capacity, were installed in or after 2011.

We estimate the two annual benefits – the value of the electricity generated, and the value of the avoided health and environmental damages – as described in Sections 3.6 and 3.7, respectively, for the year 2015. We annualize the total installation price of the system, the rebate or grant, and the investment tax credit by first expressing them in 2015 dollars using a deflator as described above; and then amortizing this value over the 20-year assumed life of each system assuming discount rates of 2 and 7 percent. We then divide the annual benefits and the annualized cost of the system by the system capacity to arrive at per-kilowatt estimates of annual costs and benefits. When we report aggregated results, we add up the annualized costs and benefits of all the systems in the unit of aggregation (e.g., a state) and divide the sum by the total system capacity within that unit, ensuring that our per-kilowatt estimates are weighted by system size and are not biased by a few small systems. Private and public costs and benefits are then estimated as described in Section 4.1 and in much greater detail in Section S2 of the SI.

4.3 Distribution of subsidies by income

We create weighted kernel density plots of the median incomes[36] of the counties represented in our dataset for each year for which we have data. We weight each county by the proportion of the total public subsidy (measured as the sum of the rebate or grant, ITC, and cross subsidy) that flowed to systems installed in that county in that year. The result is a plot such that the area under it and between two levels of income X_1 and X_2 represents the proportion of the total subsidy given that year that flowed to systems installed in counties with median incomes of between $\$X_1$ and $\$X_2$. We also create a kernel density plot of all the median incomes of all the counties in the United States, weighted by the proportion of the U.S. population[34] that lives in those counties. The area under such a plot, and between two levels of income X_1 and X_2 represents the proportion of the total population that lives in counties with median incomes of between $\$X_1$ and $\$X_2$. If much first plot (weighted by subsidy) is to the right of the second plot (weighted by population), that suggests that the subsidies flow disproportionately to richer counties.

5. RESULTS

5.1 Life-time costs and benefits of currently installed systems

Table 1 (or Figure 1) and Figure 2 summarize our results. Of the 19 states for which we have data, we present the results for the ten with the largest installed capacity of non-utility solar PV, comprising 98% of the total installed capacity. Regardless of discount rate, the private benefits exceed private costs in the majority of the states if customers are allowed to sell excess power to the electric grid at retail prices (columns J of the Table 1). If the discount rate were 2%, but it was assumed that customers could only receive the locational marginal price (LMP) for surplus electricity, private benefits would exceed private costs in only a handful of states: California, Massachusetts, New York, Nevada, and Texas (subtract columns G, additional sales at retail price, from columns J). The public cost substantially exceeds the benefit in all states and under all assumptions of discount rate (columns K). The net metering cross subsidy is a significant contributor to the net public loss: for most states, its magnitude is about half that of the net loss (compare columns G and K). Except for Maryland, when a 2% discount rate is assumed, public costs would exceed benefits even if the cross subsidy were ignored (add columns G to columns K).

<Table 1 or Figure 1 about here>

<Figure 2 about here>

5.2 Annualized per-kilowatt costs and benefits of recently installed solar PV systems

Net benefit data at county level, assuming a 7% discount rate for private benefits and costs, and a 2% discount rate for public benefits and costs , are shown in Figure 3. These data suggest that while net benefits and costs in different counties within a state are largely similar, there are circumstances in which within-state differences are considerable. This reflects the differences in solar resource available in different parts of the state. It also indicates that policies set by utilities at the local level (e.g., about net metering) are important in determining the attractiveness of distributed solar, as are system costs, which may be determined by a variety of local factors.[37] The same plot, assuming a 2% discount rate for private benefits and costs, and a 7% discount rate for public benefits and costs, is shown in Section S2.2 of the SI.

<Insert Figure 3 about here>

Figure 4 shows the distribution of annualized, per-kilowatt costs and benefits of all the systems installed in 2011-15, expressed in 2015 dollars. If a discount rate of 2% is assumed and if customers received the retail price for surplus electricity sold to the grid, private benefits would exceed costs for 90% of the systems. If the discount rate assumed is 7%, half the systems would break even. If customers only received the LMP for surplus electricity, private benefits would exceed costs for only 25% of systems if the discount rate were assumed to be 2% and for less than 10% of the systems if it were assumed to be 7%. If net metering cross subsidies are ignored, or if customers only receive the LMP for surplus electricity, public benefits would exceed costs for fewer than 10% of currently installed systems. Finally, in line with past analysis,[14] our results suggest that – at a discount rate of 7% -- the private benefits would not exceed costs anywhere in the U.S., if subsidies (in the form of the ITC and rebates) were not available.

<Insert Figure 4 about here>

5.3 Distribution of subsidies by income

Figure 5 demonstrates that subsidies flowed disproportionately to counties with higher median incomes for all systems installed in 2006, the first year in which the investment tax credit was made available. For systems installed in 2014, the distribution is closer to that of the population, but subsidies till flow disproportionately to the better-off. The total subsidy per kilowatt of installed capacity has fallen from $6000 in 2006 to $2600 in 2014; excluding the net metering cross subsidy, it has fallen from $5200 in 2006 to $1400 in 2014. At the same time, we estimate that the total, lifetime subsidy made available to systems installed in 2006 will be $200 million, but the subsidy made available to systems installed in 2014 will be $1300 million. Thus, the data paint a nuanced picture of the evolution of the distribution of subsidies: while the relative distortion between the distribution of population and subsidies has shrunk and the total subsidy *per kilowatt* of installed capacity has fallen also, the *total volume* of subsidy has (in line with the total installed capacity) risen dramatically.

<Insert Figure 5 about here>

6. DISCUSSION AND CONCLUSIONS

Our analysis answers the three questions that we posed at the start of Section 2. State and federal subsidies have made rooftop solar PV attractive to customers with low discount rates in certain states. Net metering policies that allow customers to sell surplus electricity at the retail rate would make the vast majority of systems attractive under a 2% discount rate, and about 50% of the systems attractive under a 7% discount rate. At the same time, the analysis also suggests that the public has not got its money's worth in pollution reduction from the subsidies offered to distributed solar PV: rebates and credits vastly exceed health and environmental benefits. Furthermore, these subsidies have disproportionately accrued to the better-off.

<Insert Figure 6 about here>

<Insert Figure 7 about here>

However, we acknowledge that our conception of the public benefit may be too narrow, for several reasons. First, we have valued CO_2 reductions at $40 per metric ton of CO_2. However, it can be argued that this number does not adequately account for the damage caused by global warming; for example, on the economic growth of developing countries.[38] Figure 6 shows the CO_2 price that must be assumed for the public to "break even" on the subsidies provided recently-installed distributed solar PV systems. This breakeven price was calculated by subtracting the monetized air quality (NO_x, $PM_{2.5}$, and SO_2) benefits from total subsidy (federal ITC, rebates, and net metering cross-subsidy) and dividing by the mass of avoided CO_2 emissions. Figure 7 shows the CO_2 price that must be assumed for overall benefits to equal costs. This was calculated by subtracting the value of electricity produced (assuming the LMP for sales to the grid), and the monetized air quality benefit from the total installed price of the system, and dividing the difference by the mass of avoided CO_2 emissions. In both cases, the calculations were performed based on the per kilowatt, per year, estimates of the quantities concerned, as shown in Figure 2. These estimates are not very different – and are in many cases much smaller – than more comprehensive estimates of the social cost of carbon.[38] Of course, scholars have argued that only 7-23%[39,40] of these benefits would accrue to directly U.S. rate-payers or taxpayers, while others – including the Interagency Working Group on Social Cost of Carbon[41] – have argued that the nature of the climate problem justifies basing U.S. policy on global benefits and costs.[42]

Second, increasing the cumulative installed capacity of a technology results in learning, which typically reduces its unit cost.[43] To the extent that subsidies have contributed to an increase in the installed base of solar PV, they have helped reduce the price of the technology (which has fallen from $12/W$_{DC}$ in 1998 to approximately $4/W$_{DC}$ in 2014 for non-utility systems).[7] Thus, it could be argued that subsidies given to the currently installed base of systems have contributed to reducing the cost of all future systems.

Third, subsidies for novel technologies spur entrepreneurship and encourage the founding of new firms.[44] As the installed base of the technology expands and familiarity with the technology grows, entrepreneurs' cost of capital falls, it becomes easier to partner with other businesses (e.g., in the case of solar with roofers and electricians), and to find employees.[45] Indeed, our dataset suggests that the number of installers has grown from 17 in 1998, to 514 in 2006, to nearly 2,900 in 2015. The geographical footprint of the industry also grew dramatically: our dataset suggests that there were new solar PV installations in fewer than 50 counties in 1999, in nearly 300 counties in 2006, and in nearly 700 in 2010. This growth brings jobs and other direct and indirect economic benefits.[46] Furthermore, as the number of firms and the geographical footprint of the technology grows, regulatory institutions are formed, which provide a predictable institutional environment for firms to operate in, and reduce risk.[47]

We conclude that public subsidies have not been worthwhile, if their benefits are narrowly defined in terms of a reduction in greenhouse gas emissions and criteria air pollution. Because they are skewed towards the better-off, they raise questions of equity as well as effectiveness.

The cross subsidy – paying rooftop solar PV owners a price higher than the LMP for surplus electricity sold back to the grid – would increase the price of electricity for the vast majority of ratepayers, although recent analysis suggests that this effect is (and will likely remain) quite small.[48] Our analysis lends support to regulatory initiatives that more closely match the value of electricity at a particular time and place to the compensation offered distributed generators, while also expanding access across socioeconomic strata (e.g., by supporting community solar). In the United States, the New York Public Service Commission is in the process of implementing a "full value tariff" that includes a customer charge similar to the one currently applied, a size-based network subscription charge to recover the long-term costs of transmission and distribution, and a dynamic (real-time) price.[49] This last component would account for the marginal cost of the various services that the customer consumes (e.g., energy) and provides (e.g., distributed generation, externalities such as reduced pollution, demand response).[50] The dynamic price is designed to explicitly account for externalities, as well as social and policy goals. Thus, a policymaker who is keen to remedy the fact that subsidies for distributed generation have flowed to the well-off might means-test the various components of the dynamic price. Some have argued that the dynamic price makes investor returns less certain and may discourage investment by third parties in community solar projects (e.g., because investors may be subject to a dynamic price, but be required to offer consumers a more stable price). This issue could potentially be addressed by grandfathering certain types of fixed prices agreements into the new tariff regime. How to fairly account for distributed energy services of all kinds is a topic that is the subject of lively discussion, and we point readers to the extensive body of comments on New York's proposal[51] and to a burgeoning literature.[52,53]

Our paper presented a method to estimate benefits and costs of distributed generation, and how they vary based on the perspective (public or private), location, and time. We trust that it will inform the discussion in academic and regulatory circles.

7. SUPPORTING INFORMATION

The supporting information include descriptive summaries of the LBNL dataset, details of the methods used to analyze the data, and the results of sensitivity analyses (air quality model and discount rate).

8. ACKNOWLEDGEMENTS

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FIGURES AND TABLES

Table 1: Summary of life-time costs and benefits for systems installed in the ten states with the largest installed capacity, in 2015 dollars. California, Massachusetts, Arizona, and New York each have installed capacities far exceeding other states, emphasizing the importance of the solar resource as well as the policy framework for solar. Initial system costs and rebates are inflated to 2015 dollars using the appropriate GDP deflator, whereas benefits that occur annually (proceeds from electricity sales, greenhouse gas, and air quality benefits) are discounted at either 2% or 7% to arrive at estimates of the lifetime costs and benefits associated with all the systems installed in each state.

	A	B	C	D	E		F		G		H		I		J		K	
State	Total system size	Cost to customer (*)	Investment tax credit	Rebate or grant	Offset consumption(**)		Electricity sales at LMP (+)		Additional electricity sales at retail price / Net metering cross subsidy (++)		CO2 benefit		Air quality benefit		Net private benefit (#)		Net public benefit (##)	
	(MW)	($ millions)			2%	7%	2%	7%	2%	7%	2%	7%	2%	7%	2%	7%	2%	7%
CA	3,200	11,000	4,800	1,200	11,000	8,700	1,200	4,500	4,900	3,500	1,900	1,400	710	520	6,500	5,500	(8,300)	(7,700)
MA	890	2,300	1,000	160	2,800	2,000	160	520	590	410	370	270	390	280	1,100	570	(1,000)	(1,000)
AZ	690	2,300	980	310	1,900	1,400	200	840	960	690	540	390	130	96	800	660	(1,500)	(1,400)
NY	510	1,300	570	670	1,400	1,000	180	580	630	440	270	190	550	390	850	670	(1,000)	(1,100)
NJ	150	530	200	490	490	410	38	120	110	95	110	93	260	220	110	110	(440)	(470)
NV	140	280	120	230	360	260	45	150	180	120	110	85	37	27	310	260	(380)	(370)
CT	130	380	160	170	310	220	58	210	230	160	55	40	63	47	220	220	(460)	(420)
PA	130	420	180	150	270	210	32	94	87	68	84	66	170	140	(33)	(50)	(150)	(190)
TX	100	190	82	180	220	160	29	79	79	58	64	47	35	25	140	110	(240)	(250)
MD	79	260	110	29	180	130	33	71	62	46	53	39	100	80	14	(10)	(44)	(68)

(*) We define the 'Cost to customer' as the total price of the system, less rebates or grants, less federal investment tax credit

(**) 'Offset consumtpion' is the present value of that portion of the electricity generated by each PV system that displaces consumption (i.e., is NOT sold back to the grid) We value this portion of the electricity generated at the retail price.

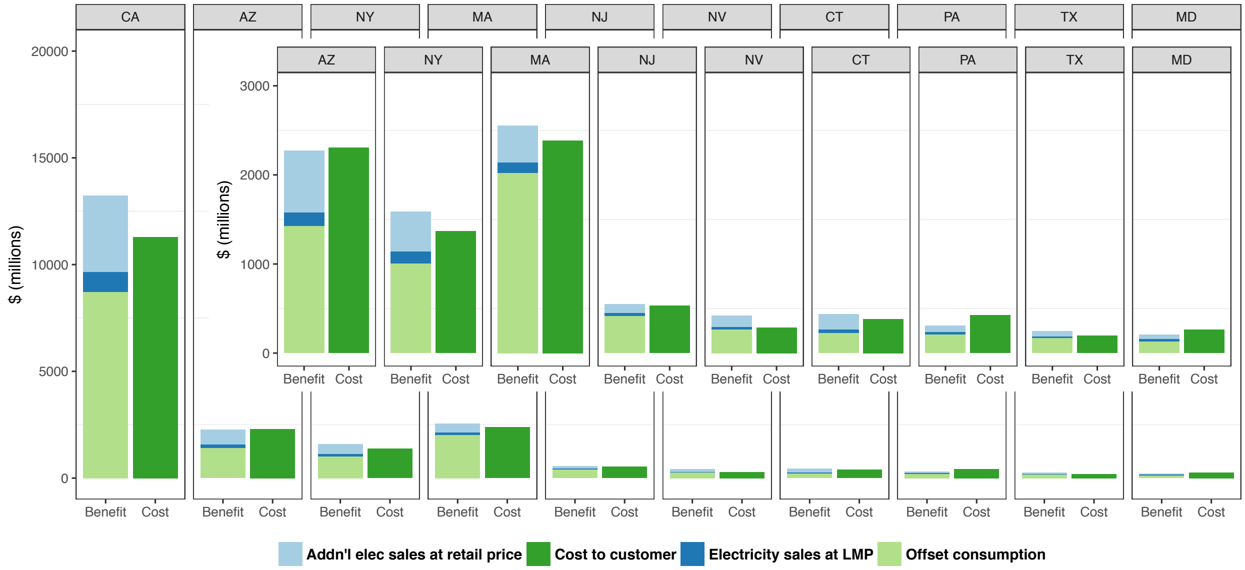
(+) 'Electricity sales at LMP' is the present value of all the electricity that was sold back to the grid (i.e., which was in excess of consumption), assuming that all such sales were at the LMP

(++) 'Additional electricity sales at retail price' is the present value of the additional sales that would be earned if electricity sold back to the grid were valued at the retail price instead of the LMP. Note that, if surplus generation was valued at the retail price, its total value would be Column (F) + Column (G)

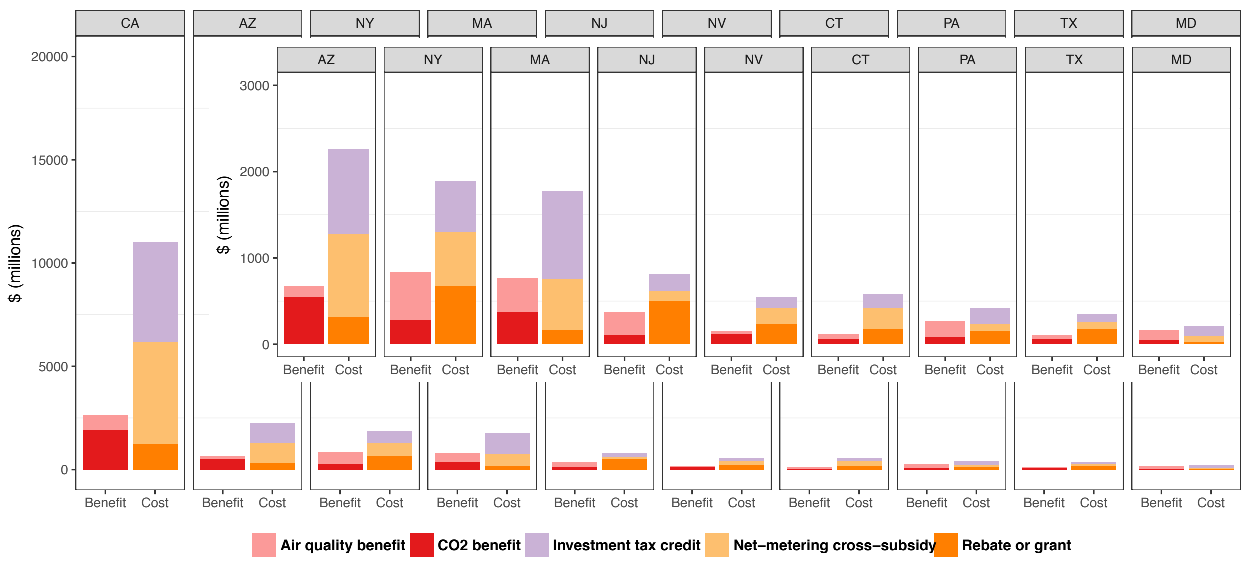
(#) The net private benefit is calculated as follows: (E) + (F) + (G) - (B). Note that sums may not add up precisely due to rounding.

(##) The net public benefit is calculated as follows: (H) + (I) - (C) - (D) - (G). Note that sums may not add up precisely due to rounding.

CA = California; MA = Massachusetts; AZ = Arizona; NY = New York; NJ = New Jersey; NV = Nevada; CT = Connecticut; PA = Pennsylvania; TX = Texas; MD = Maryland



(a) Private benefits and costs of the installed base of solar PV systems



(b) Public benefits and costs of the installed base of solar PV systems

Figure 1: Balance of total lifetime private (a) and public (b) benefits and costs of systems installed in U.S. states, expressed in 2015 dollars. Private benefits and costs are calculated assuming a 7% discount rate, which public benefits are calculated assuming a 2% discount rate. Private benefits exceed costs in California, New York, Massachusetts, Nevada, Connecticut, New Jersey, and Texas only if it is assumed that customers receive the retail price for net sales to the grid. This emphasizes the importance of the solar resource as well as grid electricity prices in determining the attractiveness of solar. In the SI, we display a similar plot for when the calculations are performed using a 2% discount rate from private benefits and costs and a 7% discount rate for public benefits and costs.

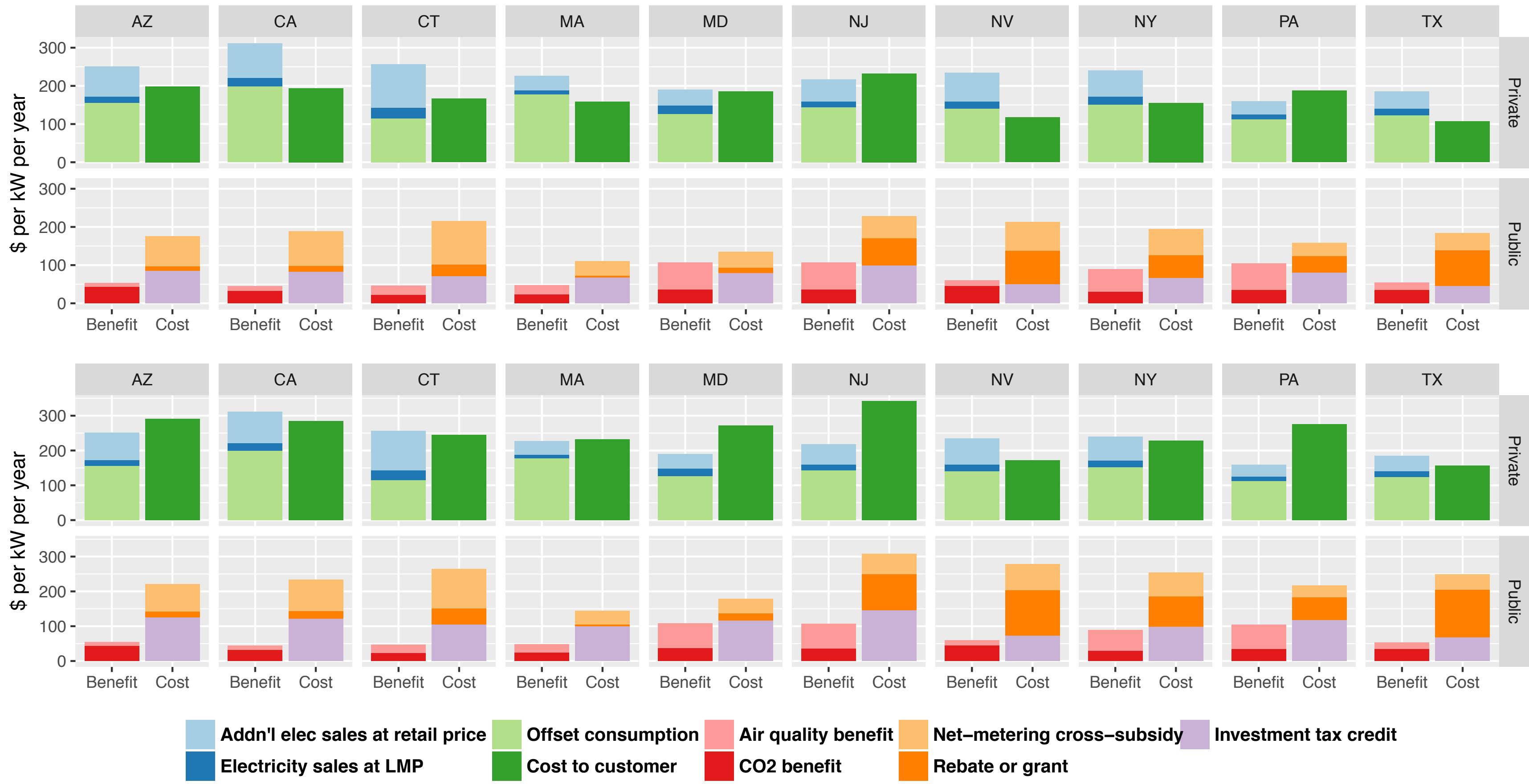


Figure 2: Balance of annualized per-kilowatt private and public benefits and costs of systems installed in U.S. states, expressed in 2015 dollars, and assuming a 2% discount rate (above) and a 7% discount rate (below). Results are sensitive to the choice of discount rate. Regardless of discount rate, if customers can sell excess power back to the grid at retail prices, private benefits exceed private costs. Benefits to the public, which stem from reduced criteria and greenhouse gas pollution are smaller than the costs, which include rebates or grants, the investment tax credit, and the price subsidy. Note that, except for Maryland and assuming a 2% discount rate, the net public benefit would be negative even if the additional value of electricity sales at retail price (equivalent to the "price subsidy") were ignored. If a 2% discount rate were assumed, the private benefit would exceed the private cost in CA, MA, NY, NV, and TX even if customers could only sell surplus electricity at LMP. In all other cases, customers would see a net loss if electricity could only be sold back at the LMP.

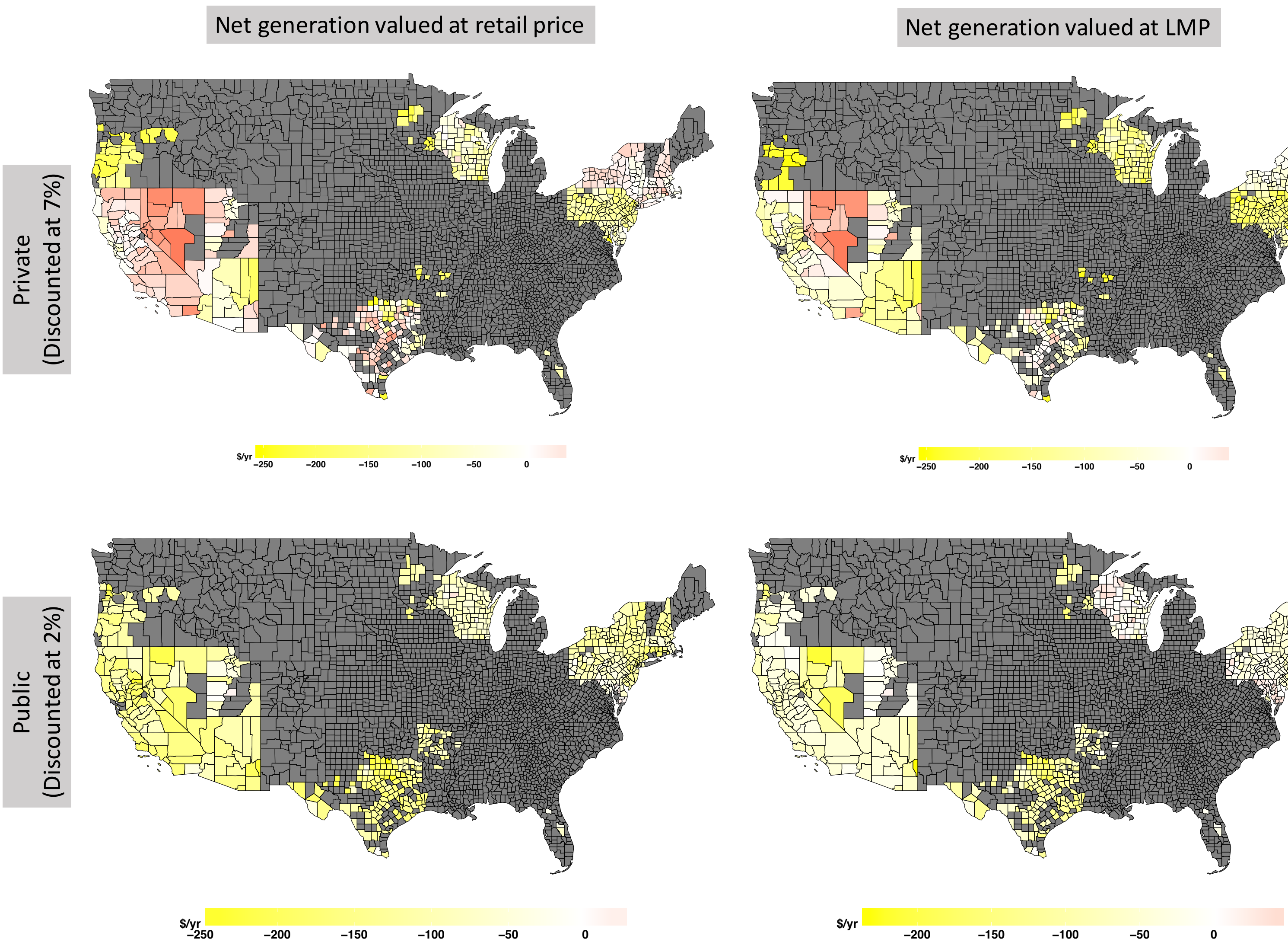


Figure 3: Net benefits by county in 2015 dollars per year, assuming a 7% discount rate for private benefits and costs, and a 2% discount rate for public benefits and costs. Private benefits exceed costs in most counties in the western U.S. if net generation is valued at the retail price, but not if it is valued at LMP. In a number of New England states with high retail electricity prices, private benefits exceed costs. Public benefits exceed costs only in some counties in the eastern U.S., provided there is no net metering cross-subsidy; i.e., net generation is valued at LMP

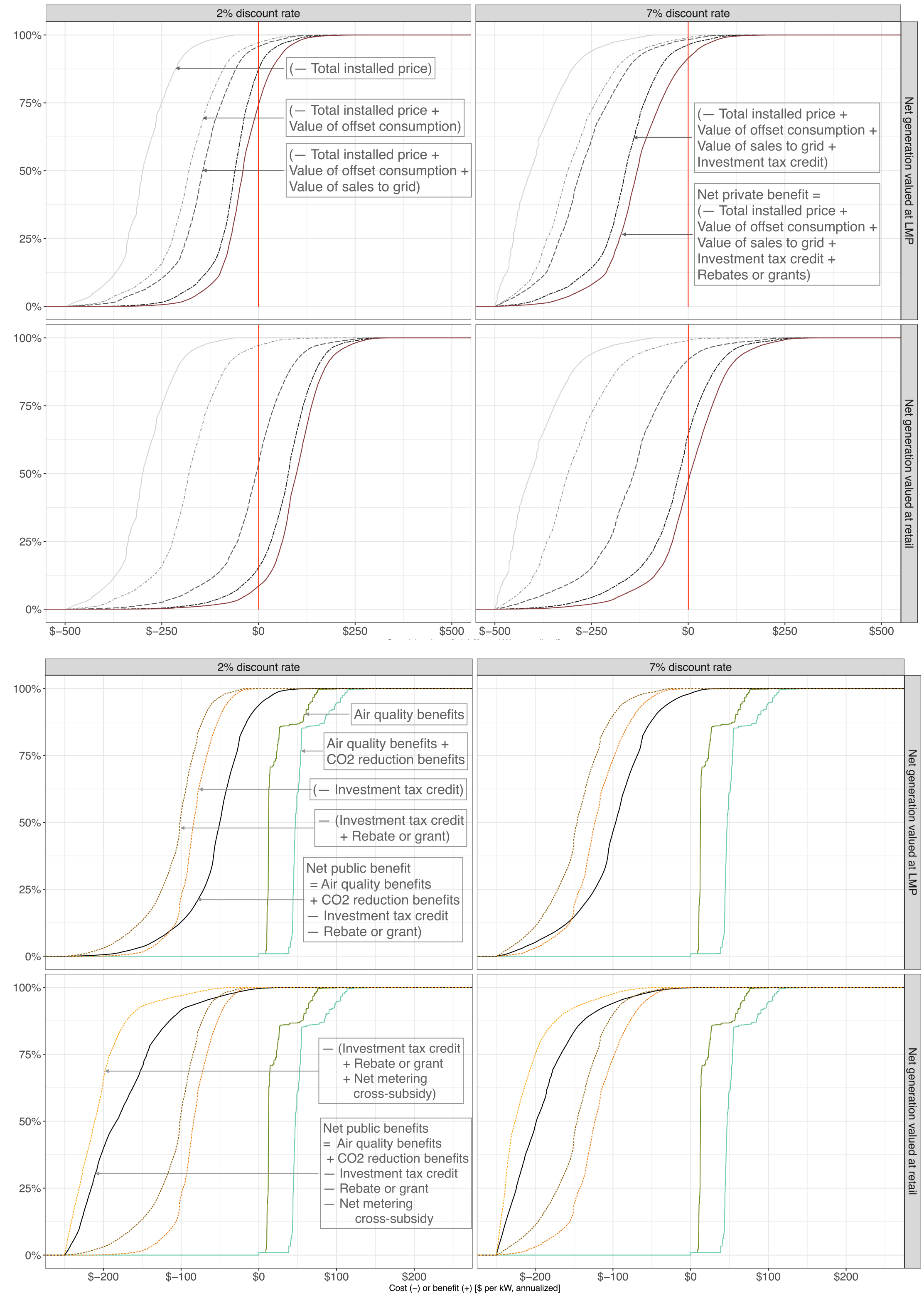


Figure 4: Distribution of private (above) and public (below) benefits and costs, expressed in 2015 $ per kilowatt per year for systems installed in 2011-15. At a 2% discount rate, and assuming surplus electricity can be sold at retail prices, private benefits would exceed private costs for more than 90% of the systems (top chart, lower left panel). Even with a 2% discount rate, and assuming installations only receive the LMP for surplus power, public benefits exceed costs for fewer than 10% of the systems.

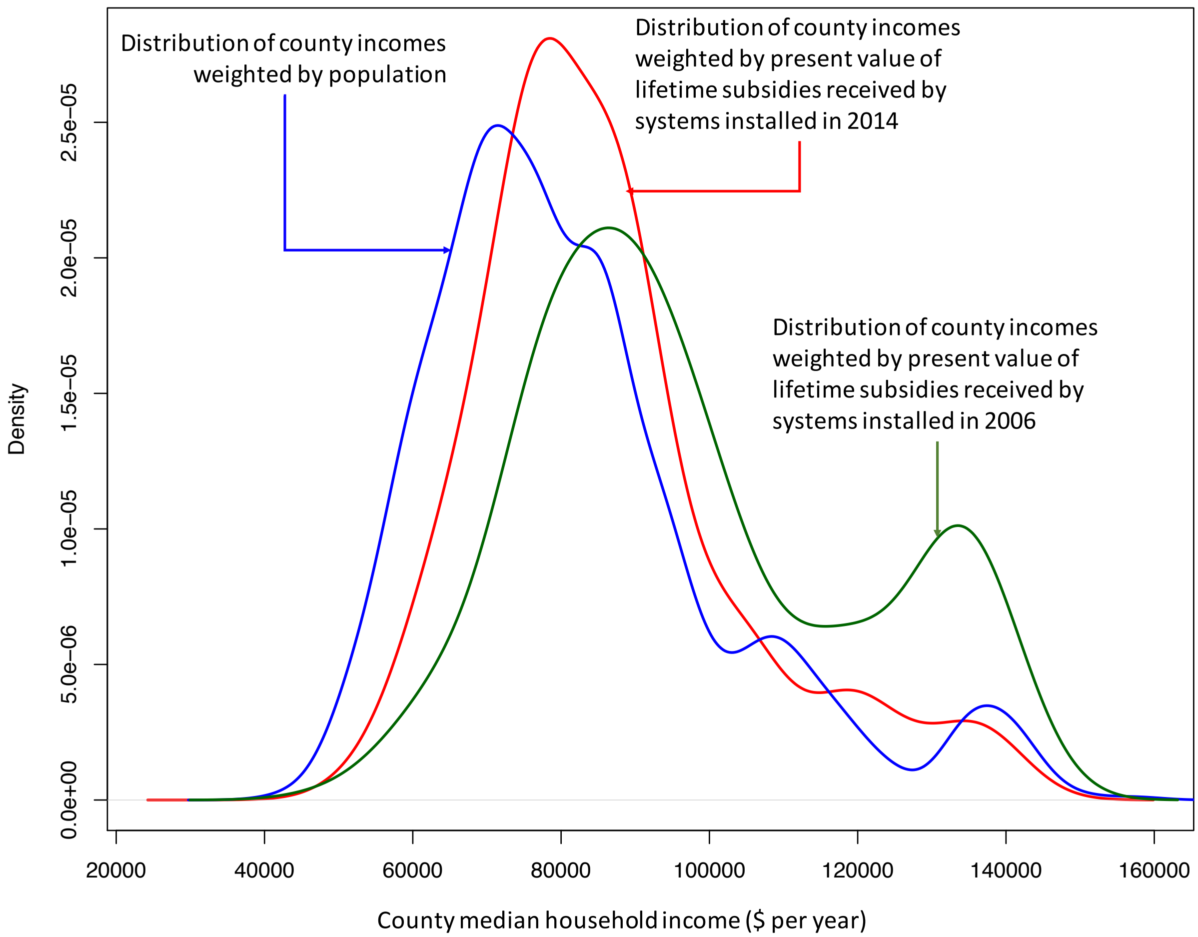


Figure 5: Distribution of county median incomes weighted by population (blue), subsidies in 2006 (green), and subsidies in 2014 (red). For the systems installed in 2006, the proportion of subsidies that flowed to richer counties was substantially larger than the proportion of the population that stayed in them. The distribution of subsidies matched the distribution of the population more closely for systems installed in 2014. Nevertheless, subsidies continue to flow to richer counties. These calculations are performed assuming a discount rate of 2%. The results are qualitatively similar if a 7% discount rate is used, and also if cross subsidies from net metering are excluded.

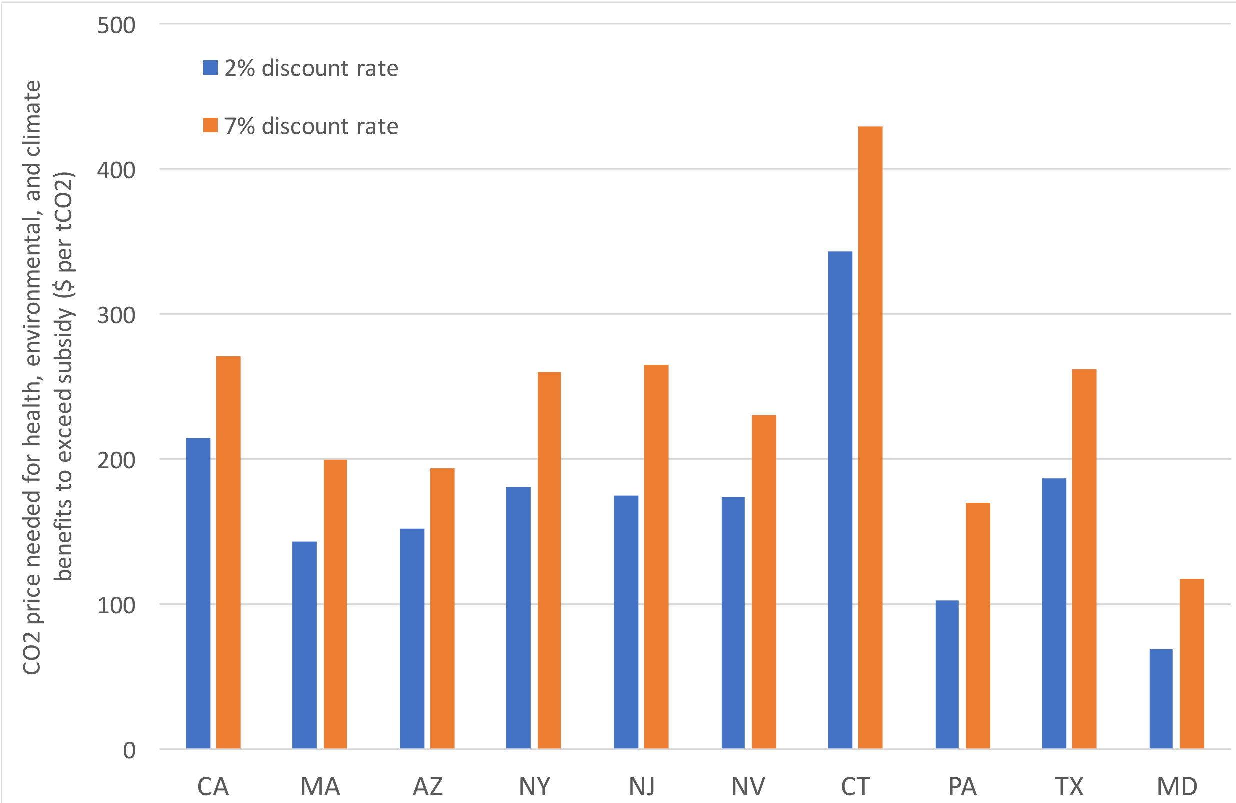


Figure 6: While the CO_2 price needed for the public to "break even" on the subsidies provided to distributed solar exceeds the U.S. Government's estimates of the social cost of carbon, these prices are not very different – and in many cases much smaller – than estimates of the social cost of carbon that account for, for example, the effect of global warming on economic growth in the developing world.[38]

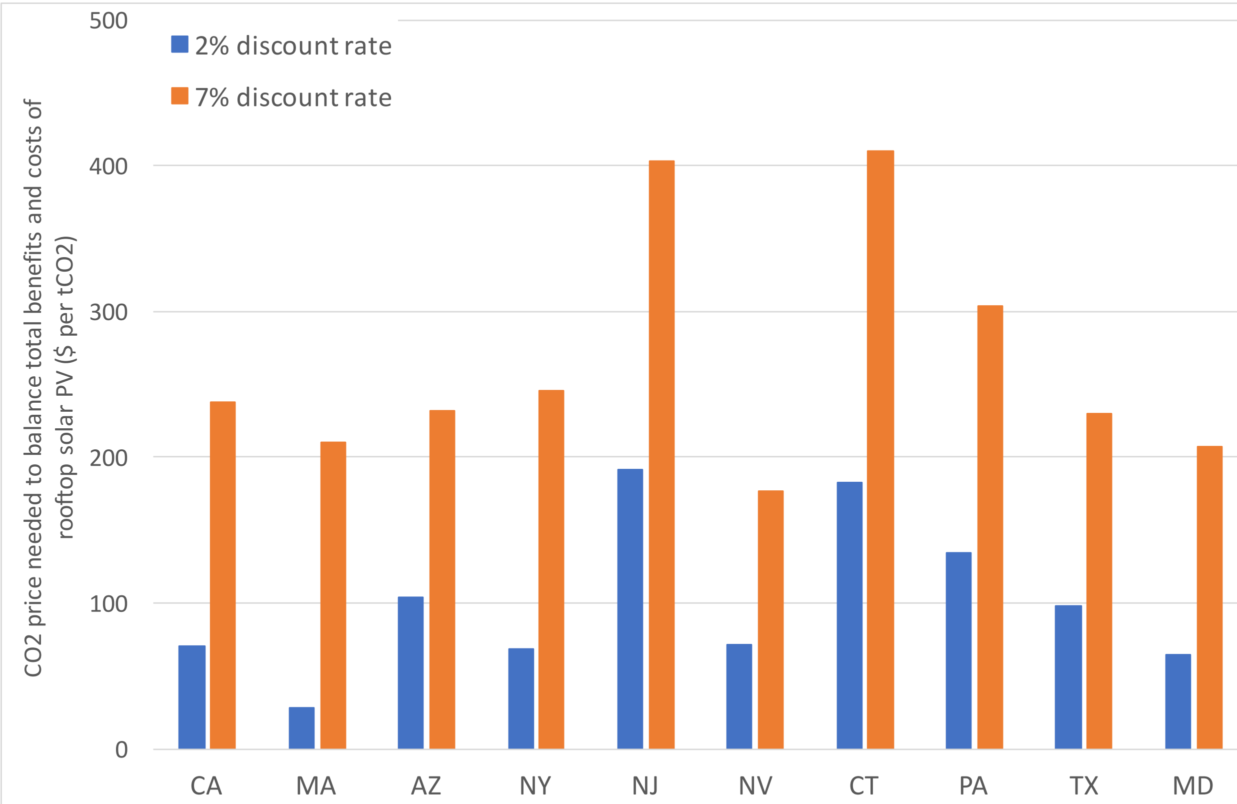


Figure 7: The price per ton of CO_2 needed for total benefits of solar PV to equal costs. In calculating this implied cost of abatement, we assume that net electricity sales to the grid are valued at LMP.

Supplementary Information for:

Was it worthwhile? Where have the benefits of rooftop solar photovoltaic generation exceeded the cost?

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S1 MATERIALS AND METHODS

S1.1 System characteristics

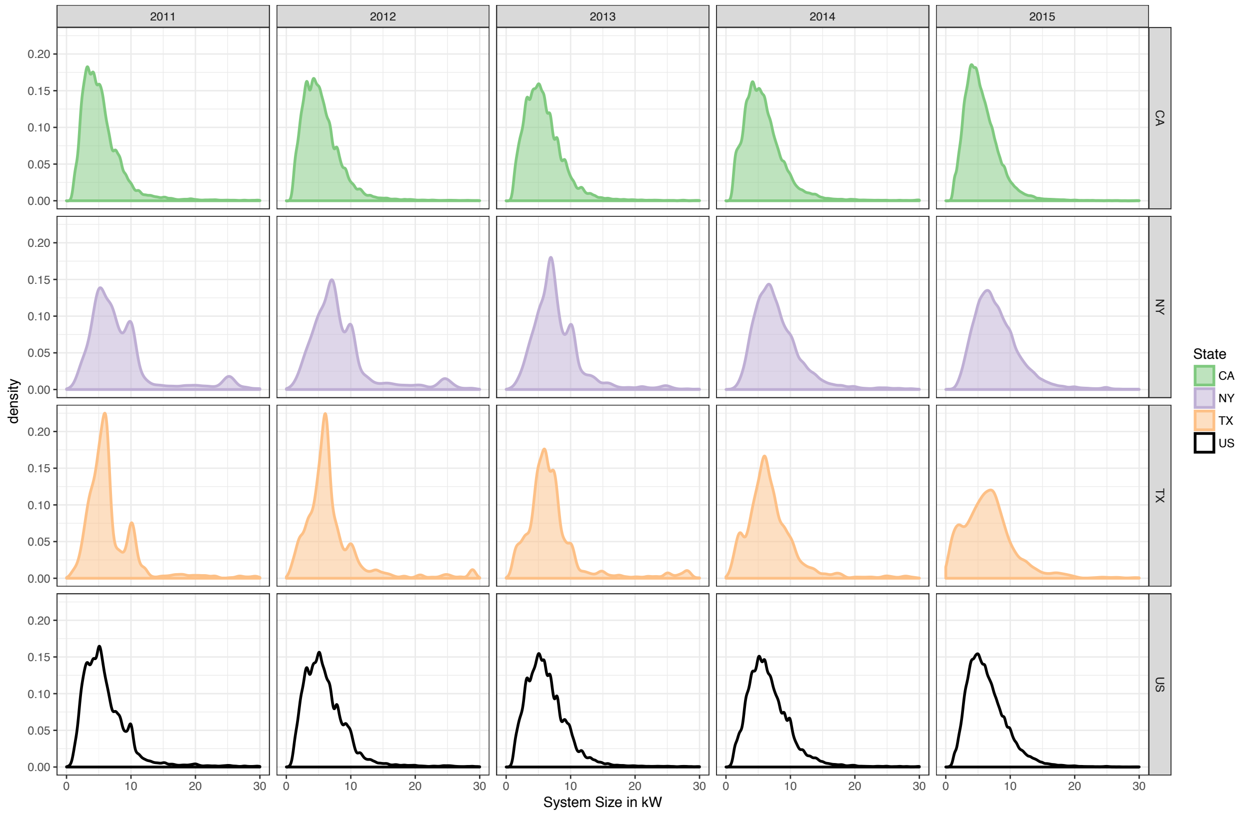

Figure S1: Distribution of the sizes of systems installed in 2011-2015

Figure S1 shows the distribution of system sizes installed in each year from 2011 to 2015 in key states, as well as the overall distribution of system sizes in the United States. We note a slight trend towards larger systems in Texas, which also has the lowest per-kilowatt costs (see Figure S2). Figure S2 also shows that prices have fallen in the five years to 2015, although the rate of increase has slowed and may even have plateaued.

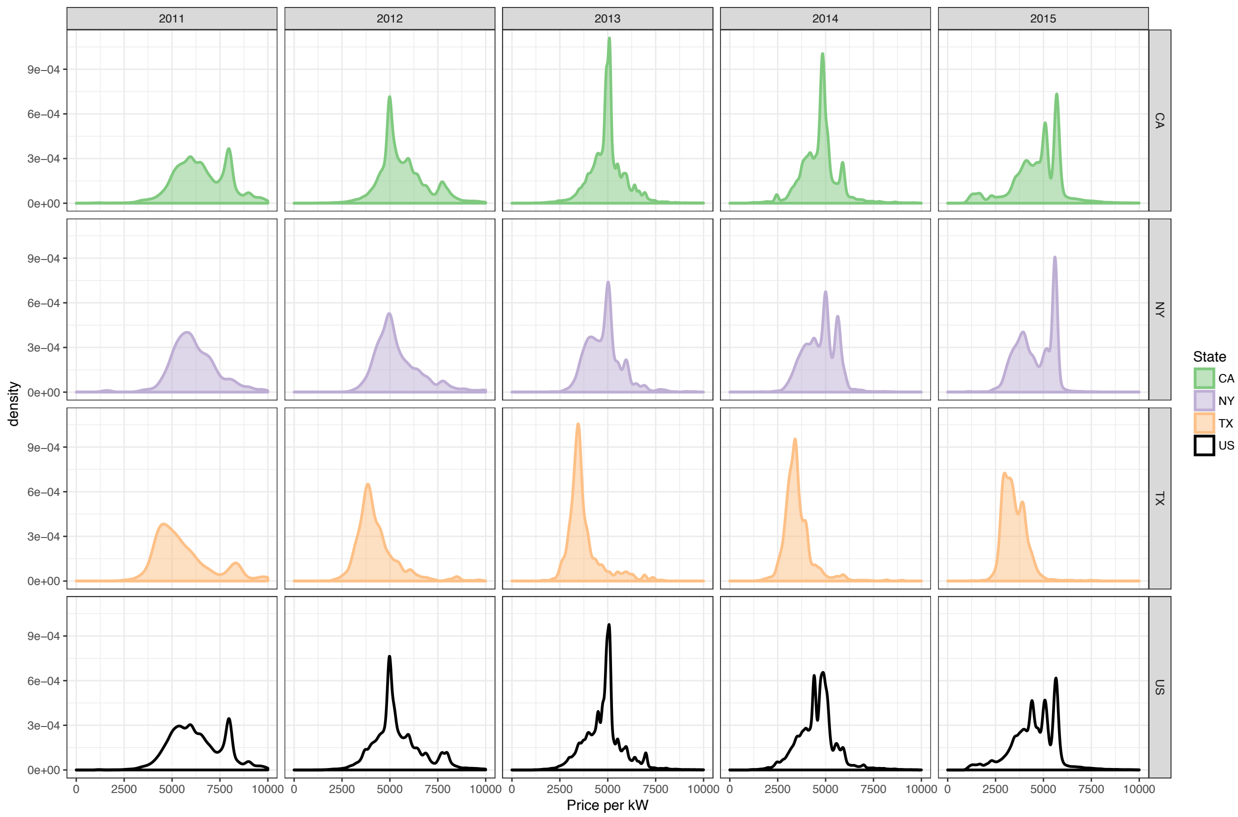

Figure S2: Distribution of system prices per-kilowatt (before tax credits or rebates) of systems installed in 2011-15

S1.2 Power generation

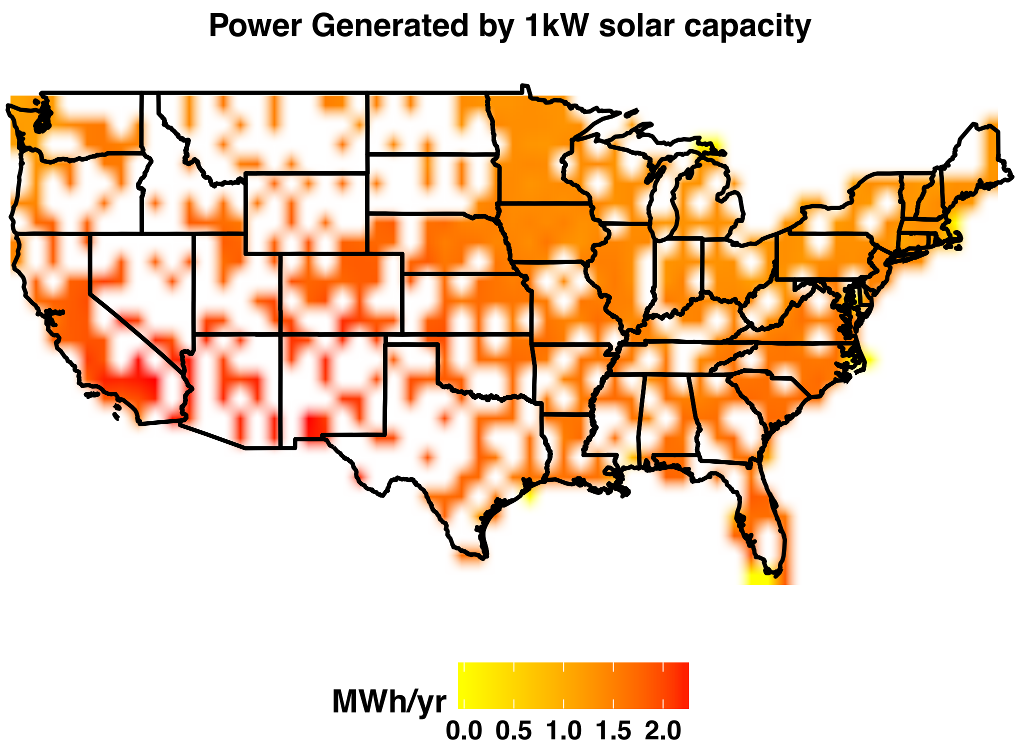

Figure S3: Power generated by 1kW of installed PV capacity in a typical meteorological year

Figure S3 is a map of the output, in MW, of a 1kW system installed at each of the sites for which insolation data is available for a typical meteorological year.[1]As Siler-Evans et al.[2] demonstrate, and as Figure 3 in the main manuscript and Figure S4 below show, the distribution of net private and public benefits depends not only on the solar resource, but also prices and the consequences of avoided pollution.

S1.3 Discount rate

The median cost of a system to customers (net of rebates and the federal investment tax credit) in the LBNL database is $19,000 (2015 dollars). This is just over half the price of a new car sold in the United States in Dec 2016.[3] As such, it seems reasonable to hypothesize that a homeowner interested in purchasing a solar PV system would be able to finance the system at rates that are lower or comparable than the rates offered on auto loans. Most American car buyers pay less than 4 per cent per year on their auto loans.[4] Unlike most cars, a solar PV system is guaranteed to produce a cash flow by offsetting at least some electricity purchases. Systems are generally purchased by households with above-average incomes, and such households can presumably borrow at a lower cost.[5] Analysis suggests that solar PV systems increase home values by slightly more than the price of the systems.[6] These factors suggest that a low discount rate of 2 per cent is appropriate.

At the same time, it could be argued that customer-owned systems ought to be valued using a discount rate related to the returns those customers might obtain from alternative investments, and that third-party owned systems ought to be valued at the cost of capital for third parties. The geometric average of S&P returns for the last ten years has been just over 7%.[7] Solar City, the largest solar provider in the US, has seen the cost of even short term bonds rise to nearly 7%.[8] Therefore, we perform all calculations at discount rates of both 2% and 7%.

S1.4 Life-cycle considerations

Our analysis has made two assumptions:

a. *The life cycle emissions of greenhouse gases and other pollutants of solar PV are negligible compared to fossil energy sources*. This assumption is supported by a series of analyses that have each concluded that greenhouse gas emissions from solar PV are at least an order of magnitude lower than those from coal- and natural gas-fired electricity generation. See, for example, Table S6 of the supplementary information associated with Hertwish *et al*.[9], Sathaye *et al*.[10], Hsu *et al*.[11], Yue *et al*.[12]. Similarly, Fthenakis and Kim[13] find that solar PV technologies emit less than 100mg/kWh of SO_2. According to the Energy Information Administration (EIA), coal-fired generation in the US -- the principal source of electricity-related SOx emissions -- 1700mg/kWh of SO_2 [14,15]. Fthenakis[16] argues, “Replacing grid electricity with PV systems would result in an 89%–98% reduction in the emissions of greenhouse gases, criteria pollutants, heavy metals, and radioactive species.”

b. *The vast majority of the greenhouse and other air emissions from fossil fuel electricity production are associated with combustion*, with a relatively small proportion coming from other parts of the life cycle. We base this conclusion on analysis by Jaramillo *et al*.[17] and Burnham *et al*.[18]

S2 METHODS

S2.1 Life-time costs and benefits of currently installed systems

We calculate the life-time costs and benefits associated with each system, s, as below.

Equation 1

$$pc_s = \partial(y_s, 2015)\times \left(i_s - g_s - \left(0.3\times k(y_s)\times (i_s - g_s)\right)\right)$$

where

pc

k(y_s) is a dummy variable that takes the value of 1 if the year of installation, y_s, of system s is greater than or equal to 2006 and zero otherwise. $k(y_s)$ ensures that the federal ITC is only applied to those systems that are installed in or after 2006.

We define the private benefit, $\boldsymbol{pb_s}$, associated with a system, s, as the 2015 present value of the electricity generated by the system in each year of operation. As discussed above, we value the electricity using a combination of retail and locational marginal prices (Equation 2a), or only retail prices (Equation 2b)

Equation 2a

$$pb_s = \begin{array}{l} \displaystyle\sum_{y=y_s}^{y=2015}\left(\left(\sum_{h=1}^{h=8760} o_{s,h}\right) \times p_{s,y} \times \partial(y,2015) + \left(\sum_{h=1}^{h=8760} (n_{s,h} \times l_{s,h})\right)\right) + \\ \displaystyle\sum_{y=2016}^{y=y_s+20}\left(\left(\left(\sum_{h=1}^{h=8760} o_{s,h}\right) \times p_{s,y} + \left(\sum_{h=1}^{h=8760} (n_{s,h} \times l_{s,h})\right)\right) \times d^{(y-2015)}\right) \end{array}$$

Equation 2b

$$pb_s = \left(\sum_{h=1}^{h=8760}(o_{s,h} + n_{s,h})\right) \times \begin{pmatrix} \sum_{y=y_s}^{y=2015}\left(p_{s,y} \times \partial(y,2015)\right) + \\ \sum_{y=2016}^{y=y_s+20}\left(p_{s,2015} \times d^{(y-2015)}\right) \end{pmatrix}$$

where,

d is the annual discount factor. We perform all our calculations using discount rates of 2%pa and 7%pa, as discussed in Section S1.3 of the SI. As such, d is either $\left(\frac{1}{1.02}\right)$ or $\left(\frac{1}{1.07}\right)$.

$\boldsymbol{o_{s,h}}$ is that portion of the output, in kWh, of the electricity generated by a system, s, in hour, h, of a typical meteorological year, that is used to offset the system owner's own consumption in that hour.

$p_{s,y}$ is the state annual-average retail price of electricity in the year *y* in the state in which system *s* is installed, and appropriate to the type of system (i.e., residential price for residential systems, and commercial price for non-residential systems). $p_{s,y}$ is expressed in nominal year *y* dollars per kWh.

$n_{s,h}$ is that portion of the output in kWh of the electricity generated by a system, *s*, in hour, *h*, of a typical meteorological year, that exceeds consumption and is sold back to the grid. We assume, as discussed in Section 3.6, that $n_{s,h} = 0$ for all non-residential systems.

$l_{s,h}$ is the average locational marginal price (LMP) that prevailed in the state in which the system was installed in hour, *h*, of 2015, the only year for which we have data. Since the LMP is expressed in nominal 2015 dollars per kWh, we do not adjust past earnings from electricity sold back to the grid to express them in 2015 dollars. We do, however, discount future earnings using the discount factor *d*.

If we assume that the customer receives the LMP for the electricity sold back to the grid, we calculate the cost to society, sc_s, of subsidizing system *s* as the sum of the rebate or grant offered the system owner, and the federal ITC (Equation 3a). If we assume that the customer receives the full retail price of any electricity sold back to the grid, we also add the "net metering cross-subsidy" received by the customer, as discussed in Section 3.8 (Equation 3b). Note that Equations 2a and 3a correspond to the case where the customer receives the LMP for any electricity sold to the grid. Equations 2b and 3b represent the case where the customer receives the retail price for electricity sales to the grid.

Equation 3a

$$\mathrm{sc_s} = \left(y_s,\ 2015\right) \times \left(g_s + 0.3 \times k(y_s) \times (i_s - g_s)\right)$$

Equation 3b

$$sc_s = \partial\left(y_s,\ 2015\right) \times \left(g_s + 0.3\times\ k(y_s)\times\ (i_s - g_s)\right)$$

$$+ \sum_{y=y_s}^{y=2015} \left(\sum_{h=1}^{h=8760} \left(n_{s,h}\times\left(p_{s,y}\times\partial(y, 2015) - l_{s,h}\right)\right)\right)$$

$$+ \sum_{y=2016}^{y=y_s+20} \left(\left(\sum_{h=1}^{h=8760} \left(n_{s,h}\times\ \left(p_{s,\,2015} - l_{s,h}\right)\right)\right)\times d^{(y-2015)}\right)$$

All the variables are as defined in Equation 1 and Equation 2.

Finally, using Equation 4, we calculate the present value of the benefits to society, sb_s, associated with the reduction in emissions of CO_2, SO_2, NO_x, and $PM_{2.5}$ produced by system *s*.

Equation 4

$$sb_s = \ k(y_s)\times \sum_{y=y_s}^{y=2006} \left(\sum_{h=1}^{h=8760} \left((o_{s,h} + n_{s,h})\times m(2006)_{\,s,h}\right)\right)$$

$$+ \sum_{y=2007}^{y=2014} \left(\sum_{h=1}^{h=8760} \left((o_{s,h} + n_{s,h})\times m(y)_{\,s,h}\right)\right)$$

$$+ \sum_{y=2015}^{y=y_s+20} \left(\left(\sum_{h=1}^{h=8760} \left((o_{s,h} + n_{s,h})\times m(2014)_{\,s,h}\right)\right)\times d^{(y-2015)}\right)$$

where

k(y_s) is a dummy variable that takes the value of 1 if the year of installation, y_s, for system *s* is less than or equal to 2006, and zero otherwise.

m(y)$_{s,h}$ is the marginal health and environmental damage, expressed in 2015 $ per kWh, avoided by offsetting a kWh of fossil fuel generation in hour *h* of year *y* in the eGrid region where the system s is located. The process by which we calculate it is described in Section 3.7 and in Siler-Evans *et al.*[2]

We then calculate the total net private benefit (pb_{net}), expressed in 2015 dollars, associated with currently installed systems in our dataset as

Equation 5

$$pb_{net} = \sum_{s} (pb_s - pc_s) \; \forall \; systems, s$$

and the total net public benefit associated with currently installed systems as

Equation 6

$$sb_{net} = \sum_{s} (sb_s - sc_s) \; \forall \; systems, s$$

where the sums are calculated for different aggregations of systems; e.g., all systems in a state, or all systems in a county, or all systems installed in a year.

S2.2 Annualized, per-kilowatt costs and benefits of recently installed solar PV systems

We calculate the annualized private and public cost of each system by using Equation 7, which corresponds to the "payment" function in many spreadsheet and financial analysis packages.

Equation 7

$$pc_s^{ann} = \frac{pc_s \times r}{1 - (1 + r)^{-20}} \; \forall \; s: 2011 \leq y_s \leq 2015$$

where

$\boldsymbol{pc_s^{ann}}$ is the annualized private cost of system s, expressed in 2015 dollars

$\boldsymbol{pc_s}$ is calculated as in Equation 1

$\boldsymbol{r}$ is the annual discount rate (2% or 7%)

We define the annualized public cost in Equation 8 below.

Equation 8a

$$sc_s^{ann} = \frac{r \times \partial(y_s, 2015) \times \left(g_s + 0.3 \times (i_s - g_s)\right)}{1 - (1+r)^{-20}} \quad \forall\, s{:}\, 2011 \leq y_s \leq 2015$$

Equation 8b

$$sc_s^{ann} = \frac{r \times \partial(y_s, 2015) \times \left(g_s + 0.3 \times (i_s - g_s)\right)}{1 - (1+r)^{-20}} + \sum_{h=1}^{h=8760} \left(n_{s,h} \times \left(p_{s,2015} - l_{s,h}\right)\right) \quad \forall\, s{:}\, 2011 \leq y_s \leq 2015$$

where

$\boldsymbol{sc_s^{ann}}$ is the annualized public cost of system *s*, expressed in 2015 dollars. Equation 8a applies if we assume that surplus electricity is sold at the LMP. Equation 8b applies if we include the net metering cross-subsidy; that is, if we assume that surplus electricity is sold back to the grid at the retail price (Section 3.8).

All other variables are as previously defined.

Note that we only consider those systems that were installed between 2011 and 2015, and that we amortize costs over 20 years.

The annualized private benefit is defined as in Equation 9 below.

Equation 9a

$$pb_s^{ann} = \left(\sum_{h=1}^{h=8760} o_{s,h}\right) \times p_{s,2015} + \left(\sum_{h=1}^{h=8760} \left(n_{s,h} \times l_{s,h}\right)\right) \quad \forall\, s{:}\, 2011 \leq y_s \leq 2015$$

Equation 9b

$$pb_s^{ann} = \left(\sum_{h=1}^{h=8760} \left(o_{s,h} + n_{s,h}\right)\right) \times p_{s,2015} \quad \forall\, s{:}\, 2011 \leq y_s \leq 2015$$

where

$\boldsymbol{pb_s^{ann}}$ is the annualized private benefit of system *s*, expressed in 2015 dollars. Equation 9a applies if we assume that surplus electricity is sold at the LMP. Equation 9b applies if it is sold at the appropriate retail price.

All other variables are as defined above.

The annualized public benefit is defined as in Equation 10 below.

Equation 10

$$sb_s^{ann} = \left(\sum_{h=1}^{h=8760} \left((o_{s,h} + n_{s,h}) \times m(2014)_{s,h} \right) \right) \quad \forall\, s: 2011 \leq y_s \leq 2015$$

where

$\boldsymbol{sb_s^{ann}}$ is the annualized public benefit of system *s*, expressed in 2015 dollars. The upper branch of the right-hand side of the equation applies if we assume that surplus electricity is sold at the LMP. The lower branch assumes that it is sold at the appropriate retail price.

All other variables are as defined above.

For each system, we calculate the net public and private benefit as in Equations 11 below.

Equations 11

$$netpb_s^{ann} = (pb_s^{ann} - pc_s^{ann}) \ \forall\, s: 2011 \leq y_s \leq 2015$$

$$netsb_s^{ann} = (sb_s^{ann} - sc_s^{ann}) \ \forall\, s: 2011 \leq y_s \leq 2015$$

We calculate per-kilowatt costs and benefits by dividing the annualized quantities calculated in Equations 7 to 11 by the system capacity.

Finally, we estimate annualized, per-kilowatt, costs and benefits at different levels of aggregation (e.g., county), as in Equations 12.

Equations 12

$$netpb_{county}^{ann} = \frac{\sum_s (pb_s^{ann} - pc_s^{ann})}{\sum_s q_s} \forall\, s: 2011 \leq y_s \leq 2015;\ s: s\ is\ installed\ in\ the\ county$$

$$netsb_{county}^{ann} = \frac{\sum_s (sb_s^{ann} - \; sc_s^{ann})}{\sum_s q_s} \forall\, s: 2011 \leq y_s \leq 2015;\; s: s\ is\ installed\ in\ the\ county$$

where

$\boldsymbol{netpb_{county}^{ann}}$ and $\boldsymbol{netsb_{county}^{ann}}$ are the annualized, per kW, private and public benefits associated with the systems installed in the county between 2011 and 2015, expressed in 2015 dollars.

A similar calculation can be performed for all the systems installed in a state or in the US.

A simple example illustrates why we divide the sum of annualized costs and benefits by capacity, instead of first calculating the per-kW values and then averaging. Consider a county which has one 1kW system and one 10kW system. System cost is subject to significant economies of scale (regressing system cost against capacity in our dataset using a linear model produces an intercept that is large, positive, and statistically different from zero). As such, suppose the 1kW system costs $16,000 whereas the 10kW system costs $47,500. Averaging the per-kilowatt costs would suggest that the average per-kilowatt cost in the county is $10,375. However, adding total cost and dividing by total capacity would suggest that the average per-kilowatt cost is $5,800. The second number is a more accurate reflection of the cost per-kilowatt in that county, since it is weighted towards the cost of the system that represents the bulk of the capacity in that county.

S3 RESULTS

S3.1 Public costs and benefits with AP2

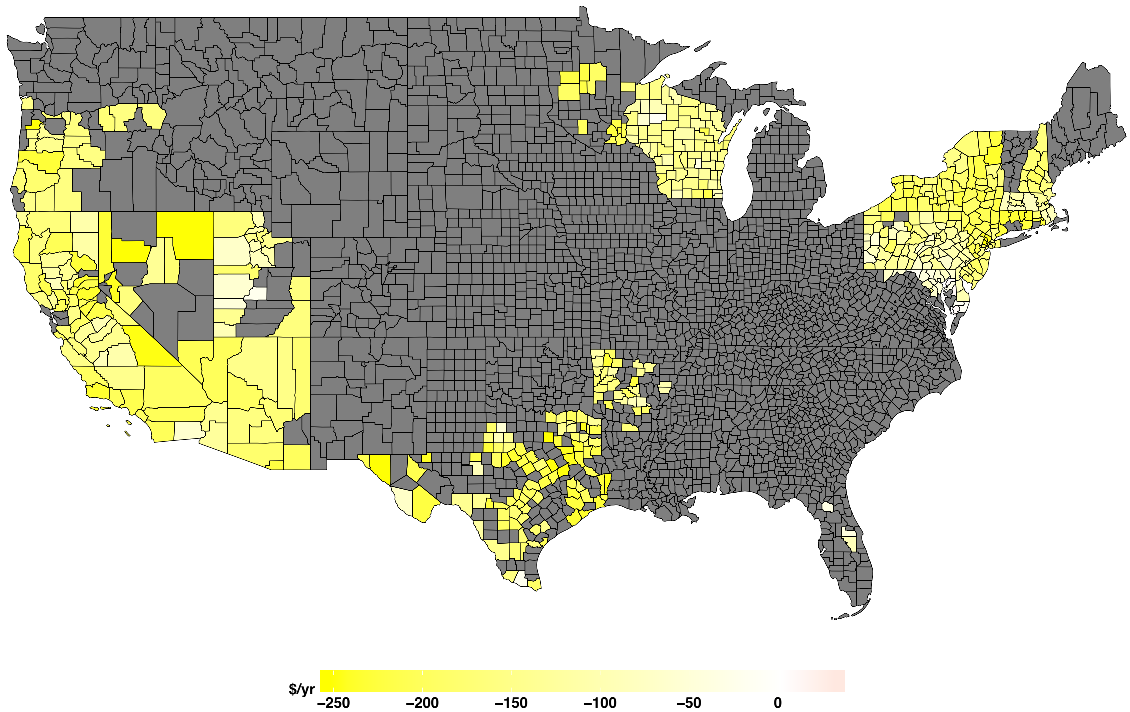

Figure S4: Net public benefit calculated using the AP2 air quality model, and a 2% discount rate. Compare to the lower left map in Figure 3 of the main text.

Figures S4 and S5, and Table S1 demonstrate that our results would not be qualitatively different if we estimated the benefits of reduced emissions of SO_2, $PM_{2.5}$, and NO_x using the AP2 air quality model, instead of the EASIUR air quality model.

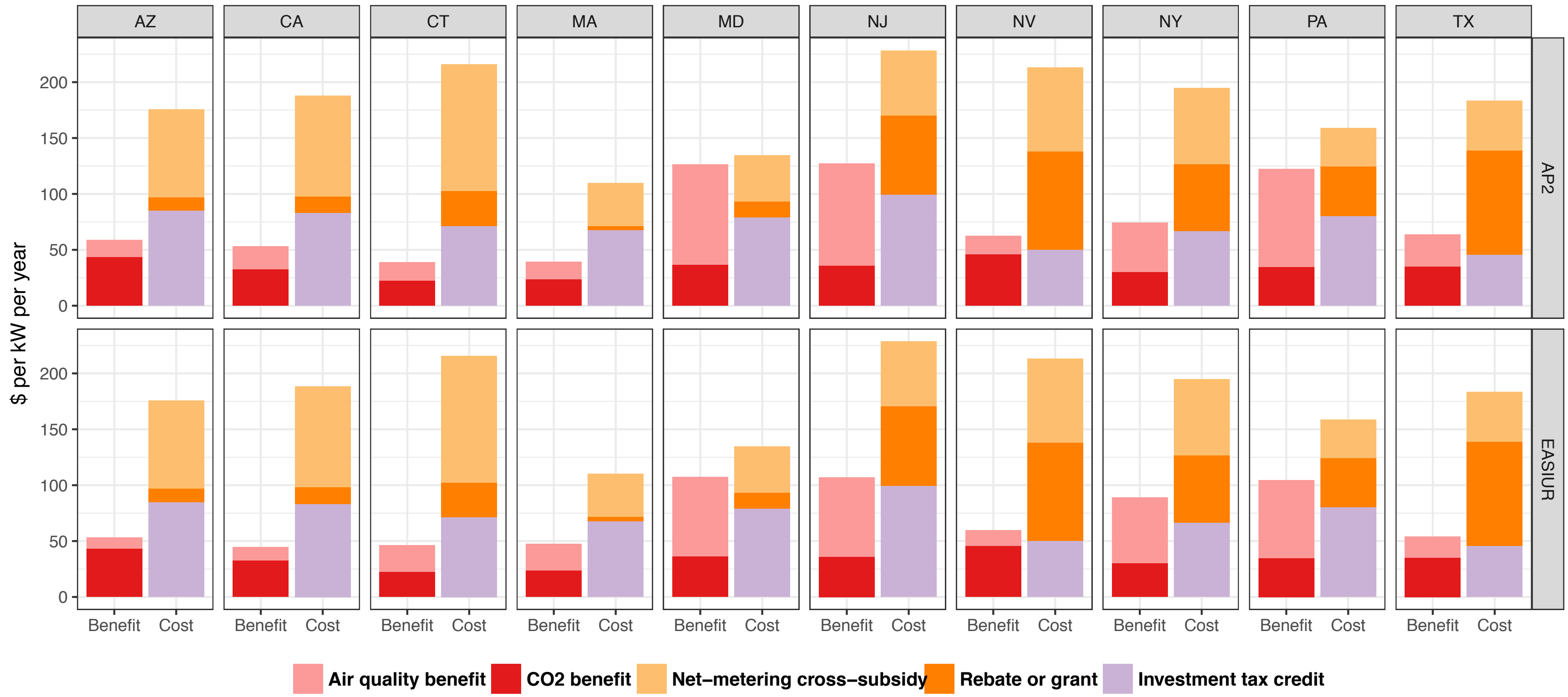

Figure S5: Public benefits and costs, assuming a 2% discount rate. The choice of air quality model (EASIUR or AP2) does not significantly alter our conclusions. Compare with Figure 2 in the main text.

Table S1: Lifetime benefits and costs for the full installed base of systems based on the AP2 air quality model. AP2 estimates that the systems will produce larger air quality benefits, notably in California. However, the overall conclusions regarding the net public benefit do not change. Compare to Table 1 of the main text.

State	Total system size	Cost to customer	Investment tax credit	Rebate	Offset consumption	Electricity sales at LMP	Additional electricity sales at retail price / Net metering cross-subsidy	CO2 benefit	Air quality benefit		Net private benefit	Net public benefit	
	(MW)	($ millions)							EASIUR	AP2	EASIUR	EASIUR	AP2
CA	3,200	11,000	4,800	1,200	11,000	1,200	4,900	1,900	710	1,200	6,500	(8,300)	(7,800)
MA	890	2,300	1,000	160	2,800	160	590	370	390	250	1,100	(1,000)	(1,100)
AZ	690	2,300	980	310	1,900	200	960	540	130	190	800	(1,500)	(1,500)
NY	510	1,300	570	670	1,400	180	630	270	550	410	850	(1,000)	(1,100)
NJ	150	530	200	490	490	38	110	110	260	340	110	(440)	(350)
NV	140	280	120	230	360	45	180	110	37	43	310	(380)	(370)
CT	130	380	160	170	310	58	230	55	63	44	220	(460)	(480)
PA	130	420	180	150	270	32	87	84	170	220	(33)	(150)	(110)
TX	100	190	82	180	220	29	79	64	35	52	140	(240)	(220)
MD	79	260	110	29	180	33	62	53	100	130	14	(44)	(16)

S2.2 Sensitivity of costs and benefits to discount rate

Figures S6 and S7 show that, if a 2% discount rate were assumed, private benefits exceed costs in all the states considered. In CA, MA, NY, NV, and TX this is true even if customers only receive the LMP for electricity sold to the grid.

Figure S6: Balance of total, lifetime private (above, assuming a 2% discount rate) and public (below, assuming a 7% discount rate) benefits and costs of systems installed in US states, expressed in 2015 dollars. Private benefits substantially exceed costs in most states. Compare with Figure 1 in the main text.

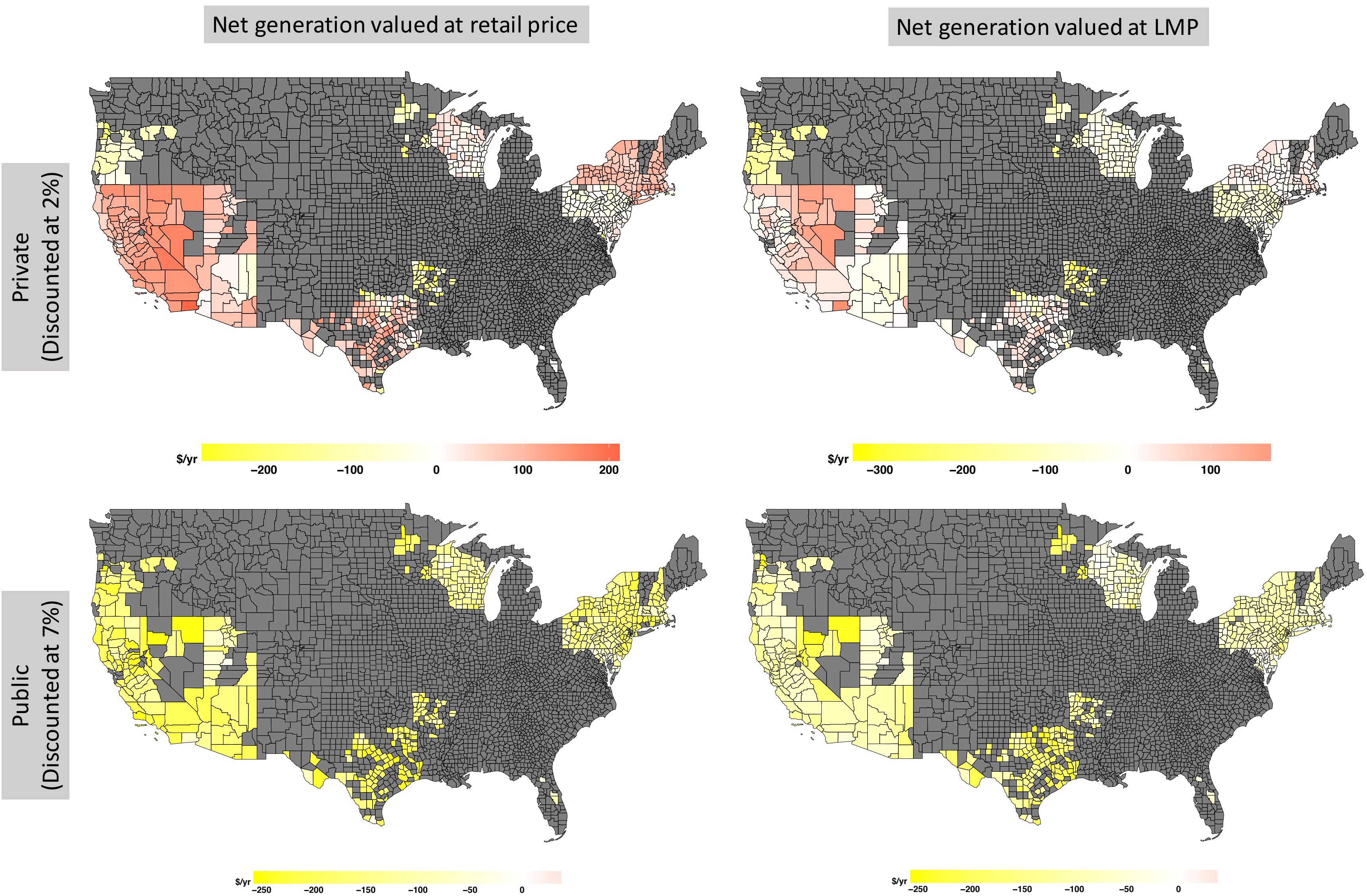

Figure S7: Net benefits by county in 2015 dollars per year, assuming a 2% discount rate for private benefits and a 7% discount rate for public benefits. Compare to Figure 3 of the main text

Figure S7 suggests that, even in states where private benefits exceed costs (e.g., California), there is considerable variation between counties. Public benefits are roughly equal to costs in some counties in north-eastern states if a 2% discount rate is applied (Fig 3 in the main text). This is no longer the case if a 7% discount rate is assumed even for public benefits and costs.

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