

# Unintended Effects of Residential Energy Storage on Emissions from the Electric Power System

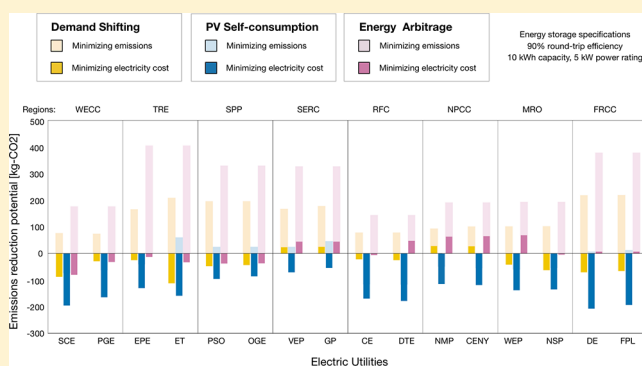
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## Supporting Information

**ABSTRACT:** In many jurisdictions, policy-makers are seeking to decentralize the electric power system while also promoting deep reductions in the emission of greenhouse gases (GHG). We examine the potential roles for residential energy storage (RES), a technology thought to be at the epicenter of these twin revolutions. We model the impact of grid-connected RES operation on electricity costs and GHG emissions for households in 16 of the largest U.S. utility service territories under 3 plausible operational modes. Regardless of operation mode, RES mostly increases emissions when users seek to minimize their electricity cost. When operated with the goal of minimizing emissions, RES can reduce average household emissions by 2.2–6.4%, implying a cost equivalent of \$180 to \$5160 per metric ton of carbon dioxide avoided. While RES is costly compared with many other emission-control measures, tariffs that internalize the social cost of carbon would reduce emissions by 0.1–5.9% relative to cost-minimizing operation. Policy-makers should be careful about assuming that decentralization will clean the electric power system, especially if it proceeds without carbon-mindful tariff reforms.



## INTRODUCTION

The world must move to a deeply decarbonized energy system over the next several decades to avert the worst consequences of climate change.<sup>1,2</sup> Energy-system analysts have laid out several potential pathways along which this transition might unfold,<sup>3</sup> and most suggest that cost-effective decarbonization will require massive electrification.<sup>4,5</sup> To provide this low-carbon electricity, many studies have focused on the role that renewable energy might play.<sup>6–8</sup> Policy makers have followed suit, promoting renewable energy as a strategy for decarbonization.<sup>9</sup>

At the same time, analysts have explored the benefits of an electric power system that is more decentralized, and policy makers in some jurisdictions, such as California and New York, are now actively promoting that future.<sup>10,11</sup> Many different political and technological forces are motivating interest in decentralization, such as the desire to empower consumers with greater control over their energy choices,<sup>12</sup> to create competition in a sector traditionally structured around regulated monopolies,<sup>13</sup> to defer costly investments in transmission infrastructure,<sup>14</sup> and to create conditions favorable to deployment of more rooftop solar photovoltaics (PV).<sup>15</sup>

Here, we focus on the intersection of these two broad areas of academic and policy attention: the potential for simulta-

neous decarbonization and decentralization of the electric power system. We assess the role of behind-the-meter battery energy storage in the residential sector, which we refer to as residential energy storage (RES). While there has been significant and growing research on the economics and technical benefits of energy storage,<sup>16,17</sup> particularly in the context of decarbonized and decentralized power grids,<sup>18</sup> our study is focused squarely on the environmental issue: if consumers on their own or in response to policy pressure adopt these systems, will greenhouse gas emissions from the electric power system go down, and at what economic cost? Here, most analysis of the effects of energy storage on emissions has focused on the role of large-scale (megawatt) systems.<sup>19–26</sup> While a couple of these studies find emissions impacts of energy storage to be case-dependent,<sup>19,20</sup> several report that revenue-maximizing energy-storage operation tends to increase emissions of CO<sub>2</sub> and other pollutants in today's power systems.<sup>21–23</sup> However, several others report that system-wide integration of energy storage could reduce CO<sub>2</sub> emissions by improving capacity utilization of renewable

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generators,<sup>24</sup> by enabling a shift from coal-fired to gas-fired generation and reducing wind curtailment,<sup>25</sup> and if some form of carbon pricing framework can be established.<sup>26</sup> Beyond the assessment of large-scale systems, several studies have also investigated the emissions effects of deploying storage technologies at the grid edge, notably in the commercial and industrial (C&I) sector.<sup>27,28</sup> Similar to the case in large-scale systems, increased CO<sub>2</sub> emissions from the grid have been observed when customers in the C&I sector operate energy storage under current tariff conditions for cost minimization.<sup>27</sup> However, certain C&I implementations of energy storage (e.g., when coupled with a combined power generation unit and an organic Rankine)<sup>28</sup> could potentially achieve emissions reductions. While the case for C&I customers deploying storage is strong under certain tariff regimes (notably when customers use these systems to reduce demand charges),<sup>29</sup> the vision of full grid decentralization hinges on more pervasive deployment of storage, including in residential settings. Assessing how RES systems would impact emissions is crucial because, in comparison to C&I customers, residential households have different power consumption behavior, they are subject to different electricity prices, and they own much smaller systems. However, the analytical literature in this domain has lagged far behind the visions for grid transformation. Existing research has assessed how different residential tariff structures might affect energy bills<sup>30</sup> or energy consumption<sup>31</sup> and associated CO<sub>2</sub> emissions. A couple of other studies has examined how RES might impact emissions when operated in modes that maximize self-consumption of PV generation in Texas and the United States<sup>32</sup> and at two locations in the United Kingdom.<sup>33</sup> Currently, there is a lack of analysis on how the wider range of possible RES operation modes could affect emissions. There is also a lack of geographical coverage generally among studies. This study aims to fill these gaps.

This study offers the first comparative analysis of the emissions impact of RES under three realistic modes of operation that span the range of plausible near-future options: demand-shifting, PV self-consumption, and energy arbitrage. The analysis samples 16 of the largest U.S. electric utilities in all 8 regional grids in the continental U.S. Using real electric tariff and marginal emissions data, we calculate the emissions effects from RES deployment in these different modes. We also calculate what households would need to be paid to shift RES operation from a goal of minimizing electricity costs to one of minimizing emissions, a calculation that reveals the shadow level of carbon pricing that can then be compared against the cost of other mitigation options.

## ■ DATA AND METHODS

We formulate a convex optimization problem that determines optimal operation for RES that minimizes either household electricity costs or emissions. Solving these problems requires information about local electricity prices, household load profiles, and solar PV generation. Solving the emission minimization problem also requires knowing grid marginal emissions factors. To address these daunting data challenges, we first build a representative sample of a large cross-section of U.S. retail customers covering all eight of the major grid regions in the U.S., known as North America Electric Reliability Corporation (NERC) regions (see Table S-1 for region abbreviations). We select the two utility service territories that are largest by customer size within each of

the eight NERC regions<sup>34</sup> (herein called region-territories) for a total of 16 region-territories.

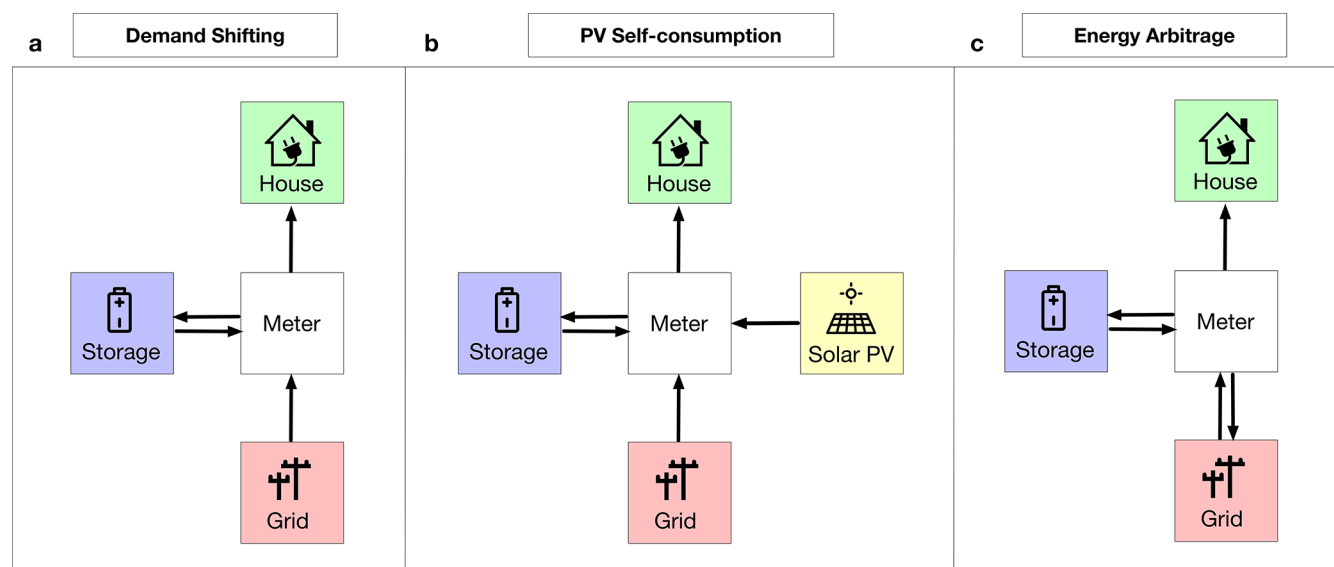
Electricity is supplied to the majority of households in the U.S. by investor-owned or publicly owned utilities at prices approved by state regulatory commissions. Supplied electricity differs by price, which varies by utility, as do bulk grid emissions, which vary by NERC region. Within each region-territory, we collect utility electricity prices as reported in time-of-use (TOU) tariff schedules and applicable adjustments, allowing us to model households' electricity costs depending on time of day, season, and location. In two NERC regions (TRE and RFC), the largest utilities do not offer a TOU tariff, so we choose the next-largest utility in the region that does (see Table S-2).

Emissions due to electricity generation vary with location and time as the type of power plants activated to supply the marginal amount of energy needed changes. We take seasonal hourly grid marginal emissions in 2016 from real-world conditions reported in the literature.<sup>35,36</sup> These emissions estimates are based on an analysis of hourly historic emissions and generation data from the Environmental Protection Agency's (EPA) Continuous Emissions Monitoring System (CEMS). We use these estimates to calculate changes in emissions caused by RES systems as they alter demand (and, thus, the emissions intensity of electricity generation that is needed to meet that demand).

We use prototypical residential load profiles provided by the U.S. Department of Energy<sup>37</sup> that are publicly available. Household consumption is reported as load profiles (i.e., annual consumption with a 1 h time step) that are the simulated electrical consumption of an archetypal house model built to the 2009 International Energy Conservation Code (IECC) as well as other standards related to domestic appliances, lighting, and miscellaneous electric loads.<sup>38</sup> Load profiles are simulated considering different climatic conditions at typical meteorological year version 3 (TMY3) weather station locations<sup>39</sup> across the United States. These characterize hourly meteorological conditions from data collected over several decades. We use the subset of TMY3 sites (and associated unique household load profiles) available within each region-territory (220 in total; see Table S-3).

TMY3 data also underlie PV generation estimation for households with solar PV systems. The power output of each PV system is determined using a PV performance model<sup>40</sup> that calculates power generation as a function of solar irradiance, ambient air temperature, and wind speed data. Typical system parameters (Table S-4) are determined using the National Renewable Energy Laboratory's PVWatts tool (<http://pvwatts.nrel.gov>). Each PV system, regardless of household location, has a 5.35 kW rating, which is the average capacity installed across the region-territories under consideration (see Table S-5).

We calculate optimal RES dispatch profiles for a full year of operation (8760 h) with two different objective functions. First, households operate RES systems to minimize household electricity costs, which is the economically rational choice. With this same goal to minimize cost, we further model a variant that adds the social cost of carbon (SCC) to the electricity cost, estimated today at \$46 in 2017 dollars per emission of metric ton of CO<sub>2</sub>.<sup>41</sup> Adding the SCC to electricity prices reveals the behavioral response of customers that internalize the carbon costs of their energy choices independent of whether that carbon is emitted locally or



**Figure 1.** Modes of operation for residential energy storage (RES) at households: (a) demand-shifting, (b) PV self-consumption, and (c) energy arbitrage. Arrows indicate the direction of power flow. Demand-shifting is the simplest mode. PV self-consumption extends demand-shifting by adding a PV system to the household. Energy arbitrage extends demand-shifting by allowing energy back-flow to the grid. Table S-6 shows the baseline configurations for each mode of operation.

from the grid. Under the second objective function, customers use RES to minimize emissions regardless of cost, which reveals the maximum potential for emissions reductions via RES.

**Three Modes of Operation for Households.** The cost and effect on emissions of achieving these two goals depends on how households operate their RES devices. We look at three modes of operation (Figure 1). These modes of operation are treated as constraints on RES systems regardless of the objective functions we describe above. First, households can use their RES as demand-shifting systems, in which RES systems shift the time of household electricity demand and minimize electricity costs under a variable TOU tariff. In this mode, households find the lowest cost for purchasing power, but they do not sell electricity back to the grid. This form of demand management is currently available in every state and utility with a TOU tariff program. Residential households have historically been charged via flat volumetric rates and, thus, have had no incentive to shift demand. Although some utilities have offered opt-in TOU tariffs, few households have made the move.<sup>42</sup> That is now changing as regulators consider mandatory TOU tariffs as part of an attempt to better capture the time-varying costs of electricity generation. In California, for example, the default residential tariff will switch to TOU for all households served by the major investor owned utilities beginning in 2019.<sup>43</sup> Furthermore, our survey on residential tariff options among 562 utilities in 2017 shows that TOU tariffs are currently being offered to residential customers in 46 of the 48 contiguous United States even though their uptake across states varies.

In the second mode of operation, which we term the PV self-consumption mode, households that have installed PV systems use RES to maximize the self-consumption of their solar PV electricity. At present, there is little incentive to use batteries in this way because nearly all states have net metering programs that credit excess power sent to the grid at retail rates. However, new proposals to alter compensation schemes for excess generation,<sup>44,45</sup> or prohibit net metering altogether,<sup>46</sup>

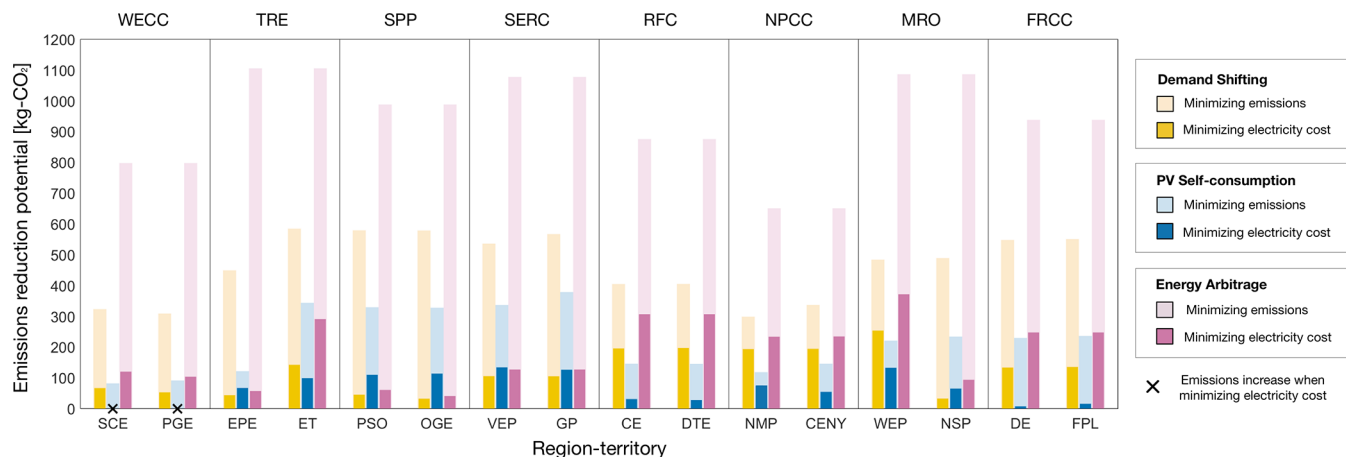
would erode or eliminate the benefits of energy sales, which could encourage RES deployment in households with PV systems and also encourage these households to operate their RES devices to maximize PV self-consumption. We compare RES operated in this mode against a baseline without RES, but that includes a PV system that is net metered, the default mode of operation today in the United States for most solar PV system owners.

Finally, in the third mode of operation, households with RES systems engage in two-way energy arbitrage, buying and selling electricity at retail rates to maximize revenue. This mode, while futuristic and quite demanding of local infrastructure and control systems, reflects the vision of advocates of decentralized energy management. Several U.S. states are currently exploring whether to allow households to exploit RES systems in this way.<sup>47–49</sup> The logic for this mode is also reflected, partly, in proposals for distributed locational marginal prices that are designed to encourage more local arbitrage and demand response.<sup>50</sup> Logically, that same kind of arbitrage could extend to residential customers, albeit at a smaller scale.

We assume each household adopts RES with a capacity of 10 kWh and a charging–discharging limit of 5 kW. This is in alignment with capacities typically offered by RES vendors, such as in the Tesla Powerwall, sonnenBatterie eco, and Evolve RES system. The 5 kW rating is sufficiently large to absorb peak solar PV generation or deliver maximum electricity demand for all modes considered in this study. In other words, RES system size is not a limiting factor in energy storage system scheduling whether operation is intended to shift demand, self-consume PV generation, or engage in energy arbitrage (details on the sensitivity of the results to different system sizes is provided in the Supporting Information).

**Household Energy Balance.** We model the household, RES, and, when present, solar PV system at a single node behind the electricity meter of the customer. The power-balance equation for household net demand  $p(k)$  at the electricity meter is given by:





**Figure 2.** Potential annual household emissions reductions with a lossless RES system in different modes of operation. NERC regions are shown along the top, with the two selected utilities in each region shown along the bottom. The bars show the mean of maximum annual emissions reductions achieved by all households in each region-territory under each of three modes of operation. For each mode of operation, we model two distinct objectives: minimizing electricity cost (dark bars) or minimizing emissions (light bars). Even when RES is assumed to be lossless (as shown here), two cases (in WECC) still lead to emissions increases when households minimize electricity cost. Such cases become more common when the same calculations are repeated considering battery inefficiencies (see Figures S-3 and S-4).

$$p(k) = l(k) - g(k) + c(k) - u(k) \quad (1)$$

where the time step  $k \in \{1, \dots, s\}$ , and  $s$  is the number of time steps in a day-long charging schedule. If  $\Delta t$  is the time-interval between consecutive time-steps  $k$ , then  $s = 24 \text{ h}/\Delta t$ . The average demand of the household over a period  $\Delta t$  is  $l(k)$ . Similarly, the average solar generation is  $g(k)$ , the average curtailed solar PV generation is  $c(k)$ , and the average RES charge–discharge is  $u(k)$ . All units are in kilowatts. The variable  $u$  is positive while discharging. Net demand  $p(k)$  is the demand seen by the utility and is positive when power is flowing from the grid to the household. Similarly, curtailment  $c(k)$  is positive.

We modify variables in eq 1 depending on the mode of operation. For modes without a solar PV system, solar generation  $g(k)$  and curtailed solar generation  $c(k)$  are zero for all time steps. For the energy arbitrage mode, net demand  $p(k)$  may be negative or positive, but for the demand-shifting and the PV self-consumption modes, net demand  $p(k)$  is constrained to be non-negative for all time steps because energy sales are prohibited in these modes. For the PV self-consumption mode, curtailed solar generation  $c(k)$  is equivalent to the excess solar generation that would have ordinarily been injected into the grid. In this case, it does not result in financial compensation to the customer.

In all scenarios, we use the observed data to be the day-ahead forecasts for demand  $l(k)$  and solar generation  $g(k)$  of each household, which is an assumption of perfect information. Though in practice real forecasts with some error would be used operationally, in this study we assume perfect forecasts to model the upper limit of RES performance, as is commonly done in the literature.<sup>32</sup>

**RES Model.** The rated energy capacity of the RES is represented by  $C$  in kWh. We set the initial state of charge (SOC)  $\chi(0)$  to 50% of the rated energy capacity  $C$ . We define the minimum allowed SOC and the maximum allowed SOC of the RES in kWh as  $\underline{\chi}$  and  $\bar{\chi}$ , where  $\underline{\chi} = 0$  and  $\bar{\chi} = C$ . We assume here that degradation is negligible to model the upper limit of RES performance (details on the sensitivity to degradation is provided in the Supporting Information). The relation governing SOC is then given by  $\chi(k) = \chi(0) - \sum_{k=1}^s u(k)\Delta t$ .

The RES charge–discharge  $u(k)$  consists of  $u_{\text{chg}}(k)$  and  $u_{\text{dchg}}(k)$ . The RES charge  $u_{\text{chg}}(k)$  is constrained by  $0 \leq |u_{\text{chg}}(k)| \leq \bar{u}$  and the RES discharge  $0 \leq u_{\text{dchg}}(k) \leq \underline{u}$ , where  $\underline{u}$  and  $\bar{u}$  are the discharge and charge power limit of RES, respectively. Following the literature,<sup>21,26</sup> we consider storage inefficiencies  $\eta_{\text{rt}}$  by dividing the total energy lost during charging and discharging equally between the charge and discharge cycles. Whenever the RES charges, we assume that its SOC increases by  $\eta_{\text{rt}}^{1/2} u_{\text{chg}}(k)$ . Similarly, when the RES discharges, its SOC decreases by  $\eta_{\text{rt}}^{-1/2} u_{\text{dchg}}(k)$ .

**RES Scheduling.** A convex optimization approach is taken to determine the optimal RES scheduling for each household. We code the scripts for the optimization problem using MATLAB (version 2016b) and solve it using the convex modeling framework CVX (version 2.1) and the solver Gurobi (version 7.0.2). The formulation of the optimization problem builds on previous work.<sup>51</sup> In the following formulation, we denote vectors in bold. RES is dispatched daily following the convex optimization problem:

$$\min_{\mathbf{p} \in \mathcal{R}^s} \Delta t \boldsymbol{\phi} \mathbf{p} \quad (2)$$

where  $\mathbf{p}$  is the household net demand and  $\boldsymbol{\phi}$  is the cost factor that is dependent on the objective under consideration. The objectives and associated cost vectors are defined as (1) minimizing household electricity cost,  $\boldsymbol{\phi} = \boldsymbol{\Lambda}$ , where  $\boldsymbol{\Lambda}$  is the TOU tariff that consists of pricing blocks; (2) minimizing household electricity cost while internalizing the social cost of carbon,  $\boldsymbol{\phi} = \boldsymbol{\Lambda} + \lambda_c \cdot \mathbf{ME}$ , where  $\lambda_c$  is the current social cost of carbon estimate and  $\mathbf{ME}$  is hourly marginal emission estimates of each day; and (3) minimizing emissions,  $\boldsymbol{\phi} = \mathbf{ME}$ . The social cost of carbon  $\lambda_c$  is taken as \$46 in 2017 dollars per metric ton of  $\text{CO}_2$ , which equates to \$38.4 in 2007 dollars per metric ton of  $\text{CO}_2$ . We use an inflation rate of 1.67% per year to determine the estimates for 2017.

The optimization problem is subject to an inequality constraint that describes the RES charge and discharge limits, capacity constraints, and the SOC dynamics and to an equality constraint that prevents energy-shifting between days. The inequality constraint  $\mathbf{A}\mathbf{u} \leq \mathbf{b}$  represents the dynamics of the

energy storage model described above. Its definition follows the derivation given in the literature<sup>52</sup> except that here, we also consider storage inefficiencies as described earlier. The equality constraint  $\mathbf{1}\mathbf{u} = 0$ , where  $\mathbf{1}$  is the all-1 row vector, ensures that  $\chi(s)$ , the final SOC at the end of each day (at time  $s\Delta t$ ), equals the initial SOC  $\chi(0)$  and, hence, prevents the RES from passing energy from 1 day to the next. The optimization horizon is 1 day, and RES are scheduled to minimize the objective over that horizon (see Figures S-1 and S-2).

**Estimating RES Impacts on Cost and Emissions.** To estimate the impact of deploying RES on operating costs and emissions, we first calculate a baseline (see Table S-6) in which households own neither RES nor PV (with the exception of PV self-consumption). For that baseline, electricity costs and emissions are a function solely of the hourly household electricity consumption. Each household is billed monthly based on their kWh electricity consumption via TOU pricing. We estimate the cost impact of RES by comparing the baseline electricity bill of each household (i.e., without RES) with their electricity bill with RES as typically done in the literature.<sup>21,26,32</sup> Whenever RES shifts the net demand seen by the bulk grid, the associated change in grid emissions is calculated by multiplying the consumption increase or decrease by the applicable marginal emissions at that hour.

## ■ RESULTS

We first evaluate the maximum potential impact on emissions and costs from RES systems by considering idealized lossless RES systems, which is a helpful benchmark before the addition of real-world operational considerations in the next section.

Figure 2 shows the emissions reduction potential for RES systems deployed across the 16 region-territories under each of two goals: minimizing electricity cost (bold bars) and minimizing emissions (light bars). Regional variation in emissions reduction potential reflects the variation in marginal emissions across the eight different national grids. For instance, achievable emissions reductions within Texas (TRE), where marginal generators have higher emissions during morning hours when coal is a significant source of marginal generation, are roughly double that in the northeastern United States (NPCC), where temporal variations in emissions throughout the day are much smaller because gas-fired generators are always dominant on the margin (see Figure S-5).

There is also a substantial difference between objective functions that minimize costs and emissions. Although lossless RES systems are almost always capable of reducing emissions when they are operated in ways that minimize cost, that reduction is relatively small. However, when RES systems are configured to minimize emissions via energy arbitrage (pink bars), they have, on average, about an 8-fold higher reduction potential than when configured to reduce cost.

At least two implications follow from the analysis of the maximum potential impact on emissions. First, while much policy attention has focused on promoting PV self-consumption mainly for reasons of managing reverse power flows, this mode has the lowest effect on emissions reductions in every region-territory. Our work suggests that energy arbitrage could be most effective at reducing emissions. Second, variation in the tariff structure within a single NERC region (that is, interconnected grids with common marginal emissions) has a strong impact on emissions under different RES modes. Each pair of region-territories within a given NERC region has an identical potential to reduce emissions

from energy arbitrage (see light pink bars). In contrast, where tariff structures differ across the utilities within a given NERC region, the expected emissions reductions if customers minimize electricity costs (see dark pink bars) differ significantly and most saliently for Texas (TRE) and the Midwest (MRO). Another striking example is observed in the Midwest (MRO) among households using RES for demand-shifting, where the emissions reductions achieved in Wisconsin (WEP) are over eight times higher than in Minnesota (NSP). This is driven by differences in tariff structures, including the duration, timing, and seasonality of peak pricing. Ultimately, it shows that reduction potentials are maximized when tariffs align favorably with marginal emission rates.

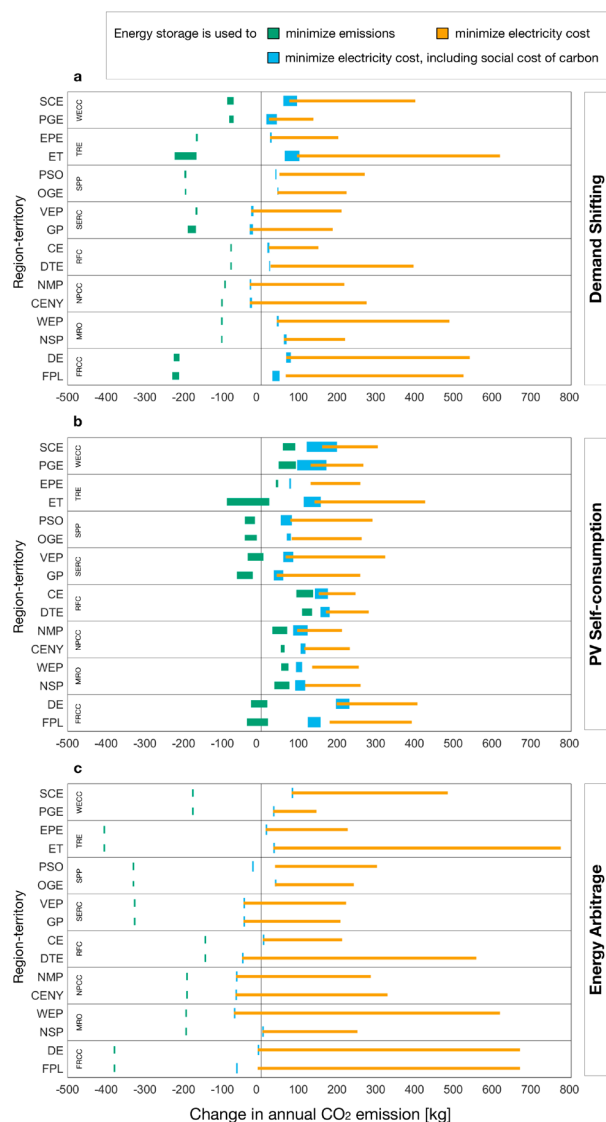
## ■ COST OF USING RESIDENTIAL ENERGY STORAGE TO REDUCE EMISSIONS

We now transition from an analysis of maximum potentials, which assumes that RES systems are lossless, to more-realistic conditions that assume 90% battery round-trip efficiency, typical of top-performing lithium-ion battery systems deployed today.<sup>53</sup> The main effect of adding battery inefficiencies is to increase emissions; losses increase energy consumption that mainly comes from fossil fuels.<sup>36</sup>

Figure 3 shows the change in annual household emissions when households operate RES systems under each of the three operating modes to minimize electricity costs (orange bars), minimize electricity costs that embed the social cost of carbon (blue bars) or minimize emissions regardless of cost (green bars). Within each bar lies the annual change in emissions estimates reported for each household. Orange bars further report the full range of possible annual change in emissions when RES systems are operated to minimize electricity. There is considerable variation in cost minimal operation (orange bars) because utility TOU tariffs are built on pricing blocks (i.e., periods of constant pricing) that last several hours. RES systems can operate along multiple different pathways within pricing blocks that minimize costs equally. Because marginal emissions vary within those TOU pricing blocks, each potential pathway has a different emissions footprint. Absent incentives to lower emissions, a large range of emissions can result from RES operation, as denoted by the orange bars. Different meteorological conditions contribute further variability for different households in a region-territory, albeit to a lower degree.

A total of three points emerge from the analysis in Figure 3. First, in each of the three modes, nearly the full range of possible outcomes for cost minimization (orange bars) involves an increase in emissions. That range of emission impacts is larger, slightly, in energy-arbitrage mode, reflecting a wider range of possible outcomes when households can move power in both directions with the grid. More importantly, while maximizing PV self-consumption, no household is able to reduce emissions compared to an equivalent household that lacks RES and has installed PV with traditional net metering. These results suggest that the outcome from tariff reforms aimed at boosting residential PV self-consumption (for example, a new settlement in Arizona<sup>54</sup> that introduces a self-consumption reimbursement rate that closely matches current export rates for excess PV generation) will be contrary to the emission impacts that PV advocates have been seeking.

Second, adding incentives to internalize the cost of emissions (here, in the form of a carbon price) significantly reduces variation in the range of potential emissions impacts



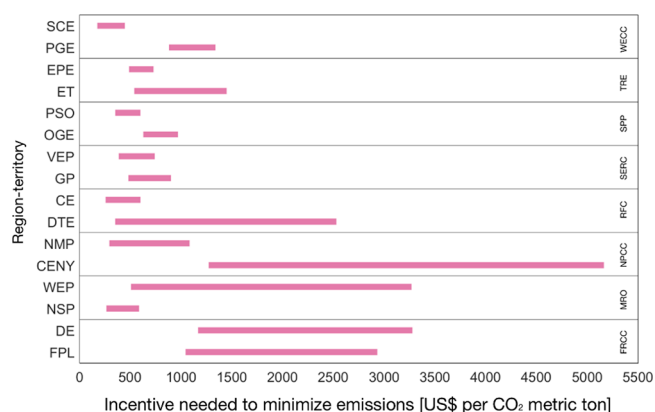
**Figure 3.** Impact on annual household emissions of using RES for (a) demand-shifting, (b) PV self-consumption, and (c) energy arbitrage. For each mode of operation, we model three different objectives: minimizing electricity costs (orange bars), minimizing electricity costs that include the social cost of carbon (blue bars), and maximizing emissions reductions regardless of cost (green bars). (a) Top and (c) bottom charts show change in emissions relative to average household electricity emissions without a PV or RES system. (b) In the PV self-consumption mode, change in emissions is determined relative to equivalent households equipped with a net-metered solar PV system without an RES system. Blue and green bars show the range of estimates, while the orange bar shows all possibilities in emission impact during a cost-minimal energy-storage operation by all households in each region-territory.

(blue bars have on average, among all modes of operation, one-tenth of the variation compared with the orange bars). A carbon price mainly shifts RES operation within a TOU pricing block (at essentially no cost) to the times that are most beneficial for emissions. As higher carbon prices would be implemented, RES would be committed more to reducing emissions directly. However, under the SCC, the savings from minimizing electricity costs far exceed the gains from avoiding emissions: the largest average annual savings from reducing emissions (those of RES operating in energy arbitrage mode at

the rightmost point of the orange bars in ET, in Texas) are less than \$35 (i.e., the SCC multiplied by the emissions savings obtained by moving from the orange bars to the blue bars), whereas the average annual savings in electricity costs are more than \$400. Nevertheless, if households responded to a carbon price equivalent to the SCC, average household emissions across all region-territories would decrease, on average, by 0.1–3.9% when demand-shifting, 0.3–2.0% when maximizing PV self-consumption, and 0.1–5.9% when engaging in energy arbitrage compared to RES operation that ignores the cost of emissions (in effect, shifting from the orange bars to the blue bars)

Third, only when RES systems are forced to minimize emissions (in effect, when the carbon price is impractically high) do they succeed in reducing emissions across all regions. Compared to the baseline, reductions reach 1.0 to 3.0% while demand-shifting, 2.2 to 6.4% during energy arbitrage, and up to almost 0.9% when they maximize PV self-consumption (see Figure S-6). RES used to maximize PV self-consumption still mostly increase emissions; the southeastern (SERC) and southern (SPP) parts of the United States are exceptions. This is because the baseline condition (residential PV with net metering) provides zero-emission solar energy to the grid during relatively high-emission hours in all other region-territories. For PV self-consumption, emissions only decline in grids with relatively low marginal emissions during peak solar hours.

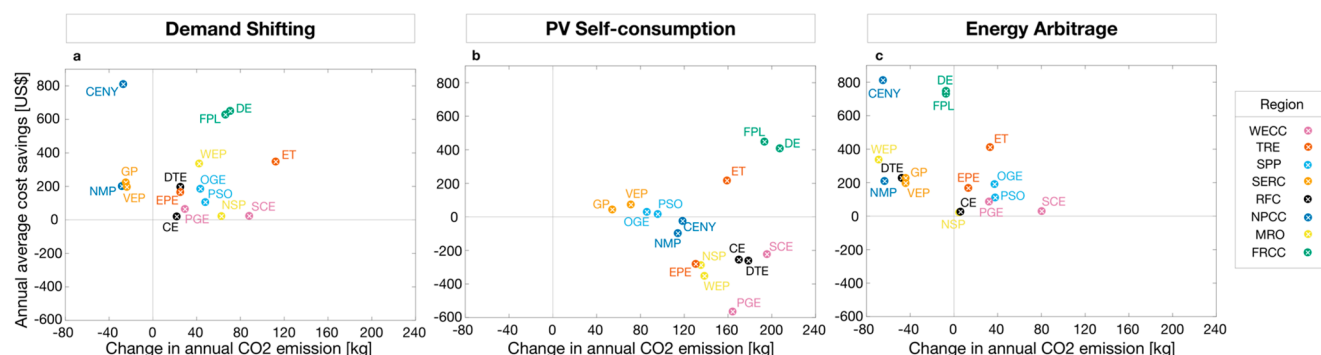
Contrasting the two objectives (minimizing electricity cost and minimizing emissions) helps us evaluate the incentives that might be needed to encourage emissions reductions via RES. Figure 4 shows the annual total that utilities would have



**Figure 4.** Carbon prices needed to achieve maximum emissions reduction under energy arbitrage. Shown are the range of prices that would need to be offered to households for operating their RES systems to minimize emissions rather than the cost of electricity during energy arbitrage. Under existing tariff structures, the cost of such interventions is high: much higher than current estimates for the social cost of carbon (\$46 per metric ton of CO<sub>2</sub>).

to pay households to reimburse economic losses they would experience when they operate with the goal of minimizing emissions instead of cost. These annual totals are derived by taking the difference in net revenue under both cost-minimization and emissions-minimization scenarios and then dividing this value by differences in net emissions under both cases. On average, this shift from cost minimization to emissions minimization allows households to reduce their annual emissions from electricity consumption by 6.8% or 460





**Figure 5.** Annual change in household savings and emissions when operating RES under (a) demand-shifting, (b) PV self-consumption, and (c) energy arbitrage. Savings and the best-case emissions reduction (left-most side of the orange bars in Figure 3) are averaged across all households in a region. Only rarely do RES systems simultaneously achieve cost reductions and emissions reductions (upper left quadrant).

CO<sub>2</sub>-kg (the amount of CO<sub>2</sub> emissions from about 52 gallons of gasoline consumed),<sup>55</sup> and in several regions (Texas and Florida, TRE and FRCC) annual reductions of more than 1000 CO<sub>2</sub>-kg are achievable (see Figure S-7). Even where reductions are significant, the associated cost of shifting to this objective is extremely high, averaging \$1100 per metric ton of CO<sub>2</sub> emissions reduced.

Variation in the incentives needed to minimize emissions across region-territories is high (from \$180 to \$5160) and mainly reflects variation in the ratio of on-peak and off-peak energy prices in each region-territory. Households with RES can achieve larger electricity cost reductions for which that ratio is higher because they can shift demand between larger price differences. For instance, there is a 10-fold difference in incentives needed between the utilities of CE and DTE (both in RFC) even though they implement the same peak pricing duration, timing, and seasonality (see Figure S-5). Households in DTE (where the ratio of on-peak to off-peak pricing per kWh is 23% greater than CE) gain more from operating their RES in an economically rational way, which makes it much costlier to implement incentives that encourage emissions reductions in this region-territory. We doubt that tariff planners intended these effects, but currently, there is a huge imbalance in the cost of emission control through RES.

In Figure 5, we summarize annual cost savings and associated changes in annual CO<sub>2</sub> emissions when households deploy RES systems to minimize their electricity costs. The energy arbitrage mode is most effective at achieving the dual benefits of reducing electricity cost and emissions: 8 out of the 16 region-territories succeed in doing so. In the demand-shifting mode, only four of the 16 region-territories achieve both cost and emissions reductions. Meanwhile, the PV self-consumption mode is unable to reduce emissions and costs simultaneously in any of the locations.

## DISCUSSION

Energy storage is widely expected to play an integral role in efforts to deeply decarbonize the electric power system. It is expected that energy storage will help integrate distributed renewable energy resources such as rooftop solar PV systems while also providing substantial operational flexibility for grid operators. Most households adopting energy storage are likely to choose equipment vendors and operation modes that allow them to minimize electricity costs. We show that, indeed, the deployment of energy storage in the residential sector can help reduce household electricity bills but that RES will also

generally lead to higher emissions. Encouraging households to temper this increase in emissions could be relatively inexpensive if done with a carbon tax, but operating RES for the goal of reducing emissions is exceptionally costly. There may be good reasons to decentralize the grid through ubiquitous installation of small RES, but cost-effective emissions control is not one of them at the moment.

An especially helpful way for policy-makers to encourage RES adoption while reducing its adverse impacts on emissions lies with the reform of utility tariff structures, which are the primary reason emissions reductions do not typically follow cost reductions. Tariffs that better reflect wholesale electricity prices and the cost of emissions could prompt simultaneous emissions and cost reductions. In grids with a low penetration of renewables, the effect of these tariff reforms could be minimal, but in grids where penetration is much higher, the impacts could be significant and merit analysis. More work is needed to understand whether such alignment could be implemented and at what cost.

Absent substantial tariff reform, policy-makers could still encourage environmentally beneficial RES operation by ensuring that system developers and equipment vendors favor clean energy use by tracking and adjusting to variations in marginal emissions of the bulk grid. Some of this work is already under way by third-party groups.<sup>56</sup>

There is much interest and enthusiasm for transformation of the electric power grid (and, with that, transformation of the whole energy system).<sup>57</sup> Enthusiasm, however, is no substitute for analysis, and there could be many unintended consequences from rapid large scale technological changes.<sup>21,27,32</sup> Decentralization of the grid could become a cauldron of unintended consequences, including for emissions of the gases that cause climate change. It will be the role of policy-makers and regulators to put in place mechanisms, such as new tariffs, that ensure that this transformation benefits both households and society in terms of cost savings and emissions reductions.

## ASSOCIATED CONTENT

### Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.8b03834.

Detailed information about electric utilities, utility rate codes and applicable riders, TMY3 weather sites considered in the study, schematics explaining each mode and baseline configuration, and sample RES dispatch figures; figures showing sensitivity on battery

round-trip efficiency, battery degradation, battery system size, solar PV system size, relative impact on annual household emissions, and mean hourly emissions estimates and peak electricity pricing periods (PDF)

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### Author Contributions

O.B. formulated the problem with contributions from all authors. O.B. wrote codes, conducted simulations, and created illustrations. All authors contributed to analyzing data and writing the manuscript.

### Notes

The authors declare no competing financial interest.

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