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Brown, David P.; Muehlenbachs, Lucija

Working Paper The Value of Electricity Reliability: Evidence from Battery Adoption

CESifo Working Paper, No. 11377

Provided in Cooperation with: Ifo Institute – Leibniz Institute for Economic Research at the University of Munich

Suggested Citation: Brown, David P.; Muehlenbachs, Lucija (2024) : The Value of Electricity Reliability: Evidence from Battery Adoption, CESifo Working Paper, No. 11377, CESifo GmbH, Munich

This Version is available at: https://hdl.handle.net/10419/305619

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David P. Brown, Lucija Muehlenbachs



Impressum:

CESifo Working Papers ISSN 2364-1428 (electronic version) Publisher and distributor: Munich Society for the Promotion of Economic Research - CESifo GmbH The international platform of Ludwigs-Maximilians University's Center for Economic Studies and the ifo Institute Poschingerstr. 5, 81679 Munich, Germany Telephone +49 (0)89 2180-2740, Telefax +49 (0)89 2180-17845, email office@cesifo.de Editor: Clemens Fuest https://www.cesifo.org/en/wp An electronic version of the paper may be downloaded • from the SSRN website: www.SSRN.com

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The Value of Electricity Reliability: Evidence from Battery Adoption

Abstract

To avoid electric-infrastructure-induced wildfires, millions of Californians had their power cut for hours to days at a time. We show that rooftop solar-plus-battery-storage systems increased in zip codes with the longest power outages. Rooftop solar panels alone will not help a household avert outages, but a solar-plus-battery-storage system will. Using this fact, we obtain a revealed-preference estimate of the willingness to pay for electricity reliability, the Value of Lost Load, a key parameter for electricity market design. Our estimate, with an average of \$4,980/MWh, suggests California's wildfire-prevention outages resulted in losses from foregone consumption of \$406 million to residential electricity consumers.

JEL-Codes: Q400, Q540, Q580.

Keywords: batteries, reliability, averting expenditures, power outages, Value of Lost Load.

David P. Brown University of Alberta / Canada dpbrown@ualberta.ca

Lucija Muehlenbachs University of Calgary / Canada & Resources for the Future Imuehlen@ucalgary.ca

September 23, 2024

This research project received support from the government of Canada's Canada First Research Excellence Fund under the Future Energy Systems Research Initiative at the University of Alberta. The authors thank the Editor, Robert Metcalfe, and two anonymous referees for their comments and suggestions. We also thank Reid Fortier, Bonnie Luo, and Zack Moline for their research assistance and Nicolas Astier, German Bet, Jenet Dooley, Naima Farah, Meredith Fowlie, Kristin Hayes, Jesse Jenkins, Ted Kury, Erin Mansur, Ignacia Mercadal, Mar Reguant, John Rust, David Sappington, Brandon Schaufele, Stefan Staubli, Frank Verboven, Frank Wolak, Joel Wood, and seminar participants at the 2022 ASSA Annual Conference, IAEE Webinar Series, Electricity Camp in the Rockies, Federal Energy Regulatory Commission, Rutgers' CRRI Workshop in Regulation and Competition, Thompson Rivers University, and the University of Florida for their helpful comments and suggestions.

1 Introduction

Recent large-scale power outages in Texas and California affected millions of households, resulting in losses of economic output, critical infrastructure, and even life (Roberts, 2019; King et al., 2021). In response to weather-related power outages, calls are increasing to spend billions of dollars on "hardening" the electricity grid to be more resilient (Dyson and Li, 2020). Decisionmakers thus face a complex task of balancing the costs of infrastructure investments with the value of improved reliability. A key component in such cost-benefit analyses is the consumers' willingness to pay (WTP) to avoid electricity outages, referred to as the "Value of Lost Load" (VoLL). Despite the importance of this parameter, decisionmakers often rely on estimates from either stated-preference surveys or macro models, having limited evidence from revealed preferences.

In this paper, we estimate the impact of power outages on the household adoption of solar-plus-battery systems, an emerging technology that serves as a defensive investment to partially or fully avoid outages. The observed adoptions provide us the unique opportunity to provide among the first revealed-preference estimates of the WTP to avoid power outages for residential customers.

Our empirical application considers the case of California's largest electric utility, Pacific Gas and Electric (PG&E), which imposed large-scale power outages in 2018 and 2019. These outages—called Public Safety Power Shutoffs (PSPS)—came in the wake of unprecedented wildfire activity and were used as a preventative measure to avoid further electricinfrastructure-induced wildfires.¹ The outages affected millions of Californians for hours to days at a time. The longest outage event in October 2019 affected 700,000 customers, with an average duration of 70 hours and some customers were without power for six days. While these intense PSPS events were irregular, there were expectations that PSPS outages would continue, as emphasized by the controversial statements made by PG&E's CEO that PSPS-

¹Fires initiated by electric infrastructure are larger than other fires because the conditions resulting in their ignition, such as high winds, are the same conditions that make the fire more easily spread (Kousky et al., 2018).

driven outages were expected to continue for up to a decade (Gonzales, 2019), though after our sample period PSPS outages decreased (Pacific Gas & Electric, 2022).

We use zip-code-level solar and battery-storage adoption data and variation in the timing, location, and intensity of power outages to analyze residential households' responses to these large-scale outage events. We have detailed information on the duration of each power outage at a granular distribution-feeder level, which we map to the zip-code level using the location of all distribution power lines in PG&E. We find that exposure to outages had a large and statistically significant impact on battery storage adoption. Although residential storage capacity is fairly small during our sample period, we estimate that capacity increased by 45 percent in treated zip codes due to the power outages. We find that the capacity additions were concentrated in zip codes with median incomes in the top 25th percentile. These findings are consistent with a growing literature that demonstrates that households in lowersocioeconomic-status regions are less likely to adopt emerging energy technologies (Carley and Konisky, 2020).

To estimate the implied value households place on reliability, we estimate a dynamic discrete choice model for the decision to adopt solar versus solar-plus-storage systems, allowing for separate zip code level estimates by median income. We estimate WTP for electric reliability of around \$4,980/MWh, ranging from \$3,451/MWh to \$6,809/MWh in the bottom to top quartile of the distribution of zip-code median income. We use these estimates to compute the damages residential households incurred as a result of foregone consumption during the PSPS outages in 2018 and 2019 in PG&E's territory. Our estimates suggest damages of \$406 million to residential customers alone. The total cost of the outages would also include damages to commercial and industrial customers. The large damages of the outages are reflected by PG&E's \$30 billion amassed wildfire liability in 2019 (Penn, 2021). When evaluating the cost-effectiveness of outages for wildfire prevention, costs should be compared to the costs of other wildfire-prevention strategies, such as restricting development in the Wildland-Urban Interface (Kousky and Olmstead, 2010; Baylis and Boomhower, 2022b), mandating fire-resistant building codes (Baylis and Boomhower, 2022a), or burying power lines underground (McCarthy, 2021; Warner et al., 2024).

Our study provides several contributions to the literature. First, our estimate is among the first revealed-preference estimates of the WTP to avoid outages—the VoLL. This parameter is widely used, for example, in evaluating the cost of reliability standards that determine investment in electric infrastructure, deciding which consumers should be subject to supply interruptions, quantifying liabilities from power outages, and setting wholesale price caps and pricing when supply is scarce (Hogan, 2013; Schröder and Kuckshinrichs, 2015).² The longstanding use of the VoLL has relied on either stated-preference surveys or macro models, due to the historical nonexistence of revealed-preference estimates (see Section A.1 for a summary).³ An exception is Harris (2023), which provides a revealed-preference estimate through observed portable generator purchases from a nationwide home improvement retailer in response to power outages and hurricane watches and warnings.⁴ Our estimates are larger than Harris (2023), possibly due to California outages being much longer in duration on average, suggesting that VoLL increases with outage duration.

Second, averting expenditures have allowed researchers to estimate the value of a wide array of nonmarket goods, including improved air quality (Neidell, 2009; Deschenes et al., 2017; Ito and Zhang, 2020), water quality (Kremer et al., 2011; Zivin et al., 2011; Wrenn et al., 2016), and the value of a statistical life (Cropper et al., 2011). However, these studies have relied on averting expenditures that reduce risk exposure alone, not an averting expen-

²Value of Lost Load estimates used in practice to set wholesale price caps in North America range from \$1,000/MWh in Alberta, to \$3,500/MWh in the Midcontinent Independent System Operator region, to \$5,000/MWh in Texas (Chang et al., 2018; Rhodes, 2022). Reliability requirements that are used to determine capacity investment set standards that limit the probability of demand exceeding supply, such as limiting the probability to less than 1 occurrence in 10 years. Murphy et al. (2020) estimate the implied VoLL that would be required to justify this standard is in the range of \$100,000–700,000/MWh depending on the stringency of the standard.

³Contemporaneous work is underway to estimate the impact of outages in three California utilities on adoption of solar-plus-batteries by Coulter et al. (2023), in Texas on generator and solar-plus-battery adoption by Adelowo (2024), and to obtain a revealed-preference estimate of VoLL using the California power outages by Burlig et al. (2023).

⁴In the case of non-residential VoLL, another exception is Beenstock et al. (1997) who estimates a revealed-preference VoLL for public-sector agencies and industrial firms in Israel using cross-sectional data on portable generator adoption.

diture that both reduces risk but also impacts another household input (e.g., reducing their electricity bill). In this context, a model that disentangles the joint benefits from a large sunk cost purchase is required. Moreover, the sunk costs of new distributed-energy technologies are rapidly changing, making it important to also capture the implications of uncertainty, such as the additional value of waiting to adopt. We provide a dynamic model that captures sunk investment costs, benefits from the nonmarket amenity (avoided outages), and a stream of co-benefits (lower bills in the future), all under uncertainty in future benefits and costs.

Third, the literature on power outages has largely been based in the context of developing countries, showing, for example, that electricity reliability increases household electricity consumption (McRae, 2015) and results in value at the household (McRae, 2015; Meeks et al., 2023; Khanna and Rowe, 2024) and firm (Fisher-Vanden et al., 2015; Allcott et al., 2016). However, our paper, provides insights into the implications of power outages in places with previously stable supply; implications that are expected to increase with the increase in extreme weather events associated with climate change (Allen-Dumas et al., 2019; NOAA, 2022).

Fourth, we find recent outages amplify the growing disparity in the adoption of emerging energy technologies. Research correlates socioeconomic and demographic factors with the adoption of a wide range of technologies, including, electric vehicles (Borenstein and Davis, 2016), rooftop solar (Sunter et al., 2019; O'Shaughnessy et al., 2021), energy efficiency (Goldstein et al., 2022), and battery storage (Brown, 2022). The pattern of an adoption discrepancy is also seen outside energy technologies, for example, in the ability to adapt to climate-related water scarcity shocks (Abajian et al., 2024). Our analysis adds to this literature by highlighting the disparity in residential households' abilities to adapt to climate-related power outages with battery storage adoption.

Fifth, we provide insights into residential battery adoption. The literature on residential distributed energy resources has focused primarily on the adoption of rooftop solar alone (Burr, 2016; Feger et al., 2017; Langer and Lemoine, 2018; De Groote and Verboven, 2019; Gerarden, 2023). In the case of residential battery adoption, Brehm et al. (2024) and Bollinger et al. (2024) also investigate factors that drive residential battery storage adoption, finding a positive relationship between residential battery storage adoption and power outages. In contrast to our focus on the willingness to pay to avoid outages, these papers study the product complementarities between residential rooftop solar and battery storage (Bollinger et al., 2024) and the optimal public provision of grid reliability in the presence of private investment in battery storage (Brehm et al., 2024). A larger literature on utilityscale adoption exists, showing social benefits from reducing prices (Butters et al., 2021), price volatility (Kirkpatrick, 2020; Butters et al., 2021; Lamp and Samano, 2022), greenhouse gas emissions (Carson and Novan, 2013; Linn and Shih, 2019), and curtailment risk (Antweiler, 2021). The residential adoptions in this paper, although smaller in scale, likely also provide several of the external benefits of utility-scale storage.

Our analysis proceeds as follows. Section 2 describes the data. Section 3 provides a summary of the power outage events in PG&E and presents preliminary evidence and statistics. Our empirical methodology and results are provided in Section 4. Section 5 presents our dynamic discrete choice model and our estimates on the WTP to avoid power outages. Section 6 concludes.

2 Data

We use multiple publicly available data sets to create a dataset on adoptions between January 2014 to June 2020. We obtained data on outage events from the California Public Utility Commission (CPUC) De-Energization database (California Public Utility Commission, 2020).⁵ These data detail all PSPS outages at the distribution line ("feeder") level and include information on the location, start and end time, and the number of customers affected.

⁵CPUC expanded the use of PSPS outages to include all investor-owned utilities, such as PG&E, starting in 2018 (California Public Utility Commission, 2018). Our de-energization PSPS outage data ends on December 31, 2019, with no additional PSPS events until September 2020 (after our sample).

We overlay PG&E's distribution line geospatial data (Pacific Gas & Electric, 2020) with the Census's Zip Code Tabulation Areas to construct a measure of outage intensity at the zip code level. We match the outage data to the distribution lines to allocate outages to zip codes. We use data on the distribution of population density from WorldPop (WorldPop, 2020) to estimate the intensity of outage exposure weighted by population density.

For data on technology adoption, we use Go Solar California's (2020) Distributed Generation Interconnection data, which include solar and battery storage interconnections that are behind the meter at customer sites. These data provide information, including the zip code, the interconnection application date, system capacity, customer class, and system costs. We focus on residential solar and/or battery storage installations in PG&E between January 2014 and June 2020. Residential adoptions represents 97 percent of all behind-the-meter solar and solar-plus-storage installations in our data (by count). PG&E experienced 90 percent of residential customer outage hours from PSPS outages during our sample period.⁶

Our dynamic discrete choice model requires additional data sources. In particular, we require multiple data sets to estimate a residential customer's annual electricity bill with and without a distributed-energy technology. For the rate schedule of customers without solar or batteries, we use PG&E's E-TOU-C residential rate schedule, the default Time-of-Use (TOU) schedule for a customer without a distributed-energy technology. For the rate schedule, the rate schedule of customers with solar-only or solar-plus-storage systems, we use the Net Energy Metering 2.0 retail rate policy that was in place in PG&E for our sample period (Pacific Gas & Electric, 2021a,b). For electricity use, we use a combination of PG&E's 2017–2020 representative hourly residential load profile and zip code-specific average monthly electricity consumption (Pacific Gas & Electric, 2021b, 2023). We use solar irradiance data from the National Renewable Energy Laboratory (NREL) Multi-Year PSM Global Horizontal Irradiance data (NREL, 2021) and NREL System Advisor Model to estimate hourly solar output.

For estimates of the cost of solar adoption, we use reported system costs on non-third-

⁶We focus on PG&E because our analysis requires access to geospatial distribution feeder-level data, which are only publicly available for PG&E.

party-owned residential solar systems in Go Solar California's (2020) Distributed Generation Interconnection data set. For estimates of the cost of battery adoption, we use data from California's Self-Generation Incentive Program (SGIP), which provides subsidies for residential battery storage projects, among other technologies (SGIP, 2020). These data provide information on system characteristics, battery costs, and subsidies.

Finally, for the median income and percent of single-family units in a zip code, we use data from the Census Bureau's five-year American Community Survey (Integrated Public Use Microdata Series, 2020).

3 Descriptive Background of the Power Outage Events

Electric infrastructure has been cited as a key driver of deadly wildfires in California (Kousky et al., 2018). In the wake of unprecedented wildfire activity, California utilities began implementing PSPS outages during periods of severe wildfire risk to reduce the threat of infrastructure-induced wildfires. Table 1 reports PG&E's PSPS outages by start date over our sample period, and summarizes the number of distribution feeders on outage, residential customers affected, and the average and maximum duration of the outages. This table illustrates the ramp-up in outages in September and October 2019 due to a series of hot, dry, and windy weeks of weather. These outages affected over 1.5 million residential customers with an average outage duration of 70 hours. Certain feeders experienced outages lasting up to 143 hours—nearly 6 days.

The PSPS outages in our sample are large compared to historical outages in PG&E. To demonstrate this, we use the EIA's Form-861 annual outage reliability data for 2013–2019 that includes outage metrics such as the System Average Interruption Duration Index (SAIDI), which measures the sum of customer-minutes interrupted by outages over the year divided by the number of total customers served (EIA, 2021). The average SAIDI between 2013–2017 equals 179.2. In 2018–2019, where PSPS outages occurred, SAIDI was 828.35 (a

Start Date	# Distribution	# Residential	Mean Duration	Max Duration
	Feeders	Customers	(Hours)	(Hours)
Oct. 14, 2018	32	40,544	30.62	60.38
June 8, 2019	21	19,500	15.42	15.42
Sept 23, 2019	17	18,524	19.66	23.47
Sept 25, 2019	44	12,182	15.00	32.12
Oct 5, 2019	17	9,981	14.27	17.70
Oct 9, 2019	415	$628,\!005$	47.58	89.13
Oct 10, 2019	26	$8,\!347$	26.31	42.93
Oct 23, 2019	136	$156,\!152$	28.87	51.55
Oct 24, 2019	5	864	27.46	37.25
Oct 26, 2019	659	$768,\!538$	70.12	143.42
Oct 27, 2019	62	60,599	56.66	101.48
Oct 29, 2019	7	497	37.60	41.78
Oct 30, 2019	1	900	0.03	0.03
Nov 20, 2019	56	$42,\!310$	26.30	38.68
NOV 20, 2019	00	42,310	20.30	00.00

Table 1: Summary Statistics of PSPS outages in PG&E by Start Date

Notes: All PSPS outage events between October 2013 - August 2020. # Distribution Feeders and # Residential Customers reflects the number of distribution lines and residential customers that were affected by an individual outage. Mean and Max Duration reflect the average and maximum length of the PSPS outages on a given start date.

362 percent increase).

PG&E is required to publish detailed reports on the methodology to determine when and where to implement a PSPS outage (e.g., Pacific Gas & Electric, 2019). PG&E first uses weather forecast models and historical weather data to identify thresholds for severe wildfire risks. If weather forecast models indicate a severe risk, PG&E identifies transmission and distribution lines within the footprint of the wildfire risk area, then uses wind speed and fire threat indices to determine which lines are at most risk and de-energizes these lines.

Figure 1 presents a heat map of the outages during our sample period by zip code in PG&E. We measure outage intensity by the residential-customer-outage hours. The precise construction of this measure is summarized in Section 4.1. Figure 1 demonstrates a considerable spatial variation in the exposure to and intensity of outages. The hardest-hit areas are those located near mountainous regions with transmission lines. However, as can be seen in the map, these are not the only regions affected by outage events.

The power outages garnered considerable controversy and criticism, but the widespread

Figure 1: Power Outage Intensity



Notes. Percentiles of total residential customer-hours of outages in zip codes in PG&E's service territory. Outages occurred October 2018–November 2019.

objections coincided with the deployment of marketing strategies by solar and storage retailers to motivate customers to install solar-plus-storage systems to circumvent future electric service interruptions (Sunrun, 2021). These systems have a distinct advantage over solar-only systems, which are unable to operate during outage events.

Figure 2 provides initial evidence that storage capacity increased in areas hardest hit by outages. This figure presents the average monthly storage capacity at the zip code level broken down by outage intensity quartiles, and shows a considerable divergence in storage investment starting in late 2019, with the regions most impacted by the outages installing the most storage capacity. An unambiguous ranking of storage investment arises by quartile of outage intensity. Although compelling, this descriptive analysis does not rigorously control for differences across zip codes.



Figure 2: Average Monthly Storage Investment by Outage Intensity

Notes. Average storage capacity investment by quartile of outage intensity. Outages started in October 2018, with the largest and most intense outages in October 2019.

While PSPS outage locations were dictated primarily by weather forecasts and fire-threat risks, these areas often coincide with mountainous regions near city centers, which happen to also be choice locations for the affluent. Table 2 presents summary statistics of the zip code characteristics by exposure to PSPS outage events, demonstrating that two-thirds of zip codes in PG&E's territory have at least one PSPS outage. PSPS outages tend to occur in regions that have a higher share of the population that is white, higher educational attainment, more owner-occupied housing, lower percentage below the poverty line, higher income, and lower density. However, we observe considerable variation in the characteristics of affected and unaffected zip codes over the full support of each of these variables. We control for differences in zip code characteristics via fixed effects in our empirical methodology, outlined next.

	Unit	No Outages	Outages
White	%	68.00	76.44
Black: Alone or in Combination	%	4.23	3.51
Hispanic: Any Race	%	39.38	18.61
Less than High School	%	21.86	10.88
High School	%	21.82	21.93
Some College	%	21.49	24.00
College or More	%	34.83	43.20
Below Poverty Level	%	16.79	12.57
Owner Occupied Housing	%	54.40	67.25
Median Household Income	\$	$73,\!412.48$	$83,\!229.60$
Median House Value	\$	$499,\!850.52$	599,311.46
Population Density	$Pop./km^2$	1,025.28	441.36
Observations	·	326	546

Table 2: Characteristics by PSPS Outage Exposure (Zip Code Average, 2019)

Notes: This table presents socioeconomic and demographic characteristics using the 2019 Census Bureau's American Community Survey data (Integrated Public Use Microdata Series, 2020), split by whether a zip code experienced a PSPS outage event during our sample period.

4 Solar-Plus-Storage Adoption: Event Study

In this section, we quantify the impact of the power outages on solar-plus-storage adoption.

4.1 Outage Intensity by Zip Code

Our outcome of interest, solar-plus-storage adoption, is measured at the zip-code-month level. We thus first construct a treatment variable to capture the intensity of outages at the zip-code-month level from data at the distribution-feeder level. The feeder data have information on which feeders experience outages, how many customers are on each feeder, and the number of outage hours. A complicating factor arises because a feeder can pass through multiple zip codes. For example, the red line in Figure 3 highlights a distribution feeder that was on an outage. It intersects multiple zip codes represented by the black lines.

We do not observe how many customers on a feeder live in a particular zip code, but assign customers to zip codes using a population-weighted measure. More specifically, we use an approach established in the geography literature that provides us with an estimate of the population distribution on a 500-by-500 meter square grid across PG&E's territory (WorldPop, 2020). The WorldPop gridded data set uses the most granular block-group level census population data and projects additional land cover topology layers (e.g., rivers, forests, roads, etc.), land use type, and machine learning models to project the census population data onto a more granular scale. The gray shaded squares in Figure 3 presents that grid of population estimates, where each square has a WorldPop cell estimate on population density. We then allocate residential customer outage hours to each zip code based on a feeder-length population-weighted measure. Appendix A.2 describes our population weights in more detail.⁷





4.2 Event-Study Specification

We exploit the variation in where power outages occur and the intensity to which outages affect residential customers to estimate the impact on the quantity of solar-plus-storage

⁷Note that we also employ weighting methods that allocate customers along a feeder based on the percentage of a feeder's line length in each zip code it intersects, assuming a uniform distribution of customers along a feeder, and find our results are robust to this alternative specification (see Table A3).

adoption. We employ the following difference-in-difference (DID) event-study framework:

Storage Capacity_{zt} =
$$\alpha_z + \delta_t + C_z \times f(t) + \sum_{\substack{k=-12\\k\neq -1}}^{8} \beta_k \, 1(t - T_z^* = k) \times \text{Outage Intensity}_{zk} + \epsilon_{zt},$$
(1)

where Storage Capacity_{zt} reflects the number of watts of storage installed in zip code z and month t.⁸ We allocate the capacity to months based on the date the application of installation was received to capture a customer's intention to adopt battery storage. We include zip code fixed effects, α_z , to capture time-invariant differences across zip codes and month-by-year fixed effects, δ_t , to capture time-varying factors that could impact technology uptake. We include zip-code-specific time trends, $C_z \times f(t)$, to absorb possible pre-existing zip code trends in distributed technology uptake.⁹ ϵ_{zt} is the stochastic error term. We cluster our standard errors at the zip code-level.

We use a continuous measure of treatment, Outage Intensity_{zk}, that captures the number of residential-customer-outage-hours (i.e., residential customers affected times the number of outage hours) in zip code z in month k. Our identification strategy relies on the assumption of no underlying trends in battery storage uptake is correlated with the exposure to and intensity of an outage, conditional on controls. To detect such trends, we consider a flexible time structure that includes leads and lags of our treatment variable. This also permits us to evaluate heterogeneous treatment effects over time. We create a series of event-month dummies, $1(t - T_z^* = k)$, which are equal to 1 when the month of the observation is k =-12, ..., 0, ..., 8 months from the date when the zip code was exposed to the treatment (T_z^*) . The omitted regressor is one month before the event (i.e., k = -1 is omitted). Observations more than 12 months before or 8 months after are captured by the indicator variables $1(t - T_z^*)$

⁸Storage capacity is measured in either the rated power capacity (watts) or energy capacity (watthours). The former reflects the amount of energy that can flow into or out of the battery in any given instant, and the latter estimates the amount of energy that can be stored. Our data often have missing values on the energy capacity, so we focus on the rated power capacity. For residential storage systems, the ratio of the power rating and energy capacity is largely constant in the data when both numbers are reported.

⁹We consider a flexible specification on f(t) that permits quadratic time trends. The Appendix Section A.5 shows specifications without these as well as different time controls.

 $T_z^* \leq -12$) and $1(t - T_z^* \geq 8)$, respectively.¹⁰

The estimated values on β_k for k < 0 capture the evolution of battery storage uptake in eventually treated zip codes before the PSPS outage, net of changes in untreated zip codes after controlling for additional model covariates. These coefficients are used to evaluate the assumption that the timing and location of outages are unrelated to pre-PSPS event changes in battery storage installations. β_k for k > 0 estimates the divergence in battery storage uptake k months after an outage, net of changes in untreated zip codes after controlling for additional model covariates. These coefficients are all relative to the excluded category, one month before the PSPS outage treatment, $t - T_z^* = -1$.

We also examine heterogeneous treatment effects by quartiles of zip-code median income and in the Appendix by quartiles of California's Environmental Justice Index (the CalEnviroScreen). In the Appendix, we also consider additional specifications where we adjust the dependent variable to be the number of storage systems adopted and the mean storage system capacity upon adoption. These alternative dependent variables allow us to decompose how much of the response to PSPS outages is due to a change in the number of systems adopted versus the configuration of those systems (e.g., via the adoption of larger systems). In addition, we run a series of robustness checks to explore the sensitivity of our results. In particular, because our identification strategy exploits a certain degree of variation in the timing and intensity of outages (recall Table 1), our treatment effects represent the weighted average of all two-by-two DID estimates (Goodman-Bacon, 2021). We employ multiple robustness checks to demonstrate our results are not driven by the concerns raised in this literature.

¹⁰We include event-month dummies for only eight months posttreatment because the largest and most intense outages occurred in October 2019 and our data set ends in June 2020, eight months after. Consequently, additional posttreatment variables are identified only off of the relatively infrequent outages that arose earlier in the sample.

4.3 Event-Study Results

Figure 4 presents the event-study coefficient estimates on Outage Intensity in Equation (1). In the pretreatment period, we do not observe systematic differences in investment in zip codes that are eventually subject to outage events. Figure 4 demonstrates a positive and statistically significant impact of Outage Intensity on battery capacity investment starting three months after an outage event.¹¹ In months 3–5, a one standard deviation change in residential-customer-outage hours corresponds to a 32 percent increase in monthly storage capacity investment, relative to the average monthly storage capacity in the full calendar year before the first outage event. Although smaller, the same comparison for month zero and two months after the outage event reflects an 11 percent increase in storage capacity investment. We observe a decline in the coefficients six months after the outage events. This decline coincides with the beginning of the Covid-19 pandemic. Regardless of this empirical difficulty, Figure 4 presents a distinct effect of outage intensity on storage capacity investment 3–5 months after an outage event.

We use the coefficient estimates to predict the amount of storage capacity installed compared to the amount of storage capacity that would have been installed in treated zip codes absent the outage events. Our estimates find an additional increase of approximately 4.86 MWs of storage capacity. Although this number is small in comparison to the level of utilityscale capacity in California, in percentage terms, it is large: we estimate a 45 percent increase in residential storage capacity due to the outage events.

Solar-only adoption is much more prevalent than solar-plus-storage, but we find that it is much less tied to outages. We examine the adoption of solar-only systems as the dependent variable in Equation (1) and find the relationship between outages and adoptions is less clear: the coefficients are noisy with increases both before and after outages, with one increase in solar-only adoption after outages but only lasting two months (Appendix Figure A1). In

¹¹The lagged effect is consistent with a delay between being exposed to the outages, deciding to adopt a solar-plus-storage system, having to search for a provider of these systems, and finalizing all the necessary paperwork before submitting an interconnection application to PG&E.



Figure 4: Impact of Outage Intensity on Storage Capacity (Watts)

Notes. Figure depicts estimates of β_k from our specification in (1) regressing installed storage capacity on leads and lags of outage intensity and quadratic zip-code-specific time trends. The shaded region reflects the 95 percent confidence intervals. Coefficients can be seen in Table A2.

contrast, although of smaller scale, the solar-plus-storage system adoption shows a distinct increase in adoptions only after treatment and lasting five months.

The outages occurred in zip codes across the income distribution, but the largest treatment effect is estimated in the zip codes with the largest median incomes. Figure 5 illustrates heterogeneous treatment effects of outage intensities on storage capacity investment separating zip codes by median income quartiles.¹² The finding of predominant adoption coming from the highest incomes is in line with the growing literature that documents disparities in distributed technology adoption by socioeconomic characteristics (e.g., Sunter et al., 2019 and Brown, 2022). More broadly, these findings raise the concern that individuals with lower socioeconomic status will face disproportional burdens associated with reduced electric reliability as a result of climate change.

 $^{^{12}}$ In the appendix, we show results by an Environmental Justice Index that captures socioeconomics, health, and environmental indicators. We find storage uptake is higher in the communities with the least environmental justice concerns, though the relationship is less strong than income alone (See Section A.6).



Figure 5: Impact of Outage Intensity on Storage Capacity by Income Quartiles

Notes. Regression estimates by subsamples of income quartiles. Figures depict estimates of β_k in Equation (1), regressing installed storage capacity on leads and lags of outage intensity and quadratic zip-code-specific time trends. The shaded region reflects the 95 percent confidence intervals. Coefficients are in Table A2.

In Appendix Figure A2, we present our event-study results when the dependent variable is (a) the number of storage systems and (b) the average storage capacity on adopted systems. These results demonstrate that the distinct increase in total storage capacity in response to the PSPS outage events presented in Figure 4 is the result of an increase in the number of storage systems adopted rather than a change in the configuration of those systems.

We consider an array of robustness checks in the Appendix and the key conclusion remains: outages led to a large percentage increase in battery-storage adoption. Section A.5 demonstrates that our key conclusion persists with alternative zip-code-specific time trends. Section A.7 presents additional model specifications that include focusing only on a comparison of the zip codes that were first and only exposed to PSPS outages in October 2019 (the largest outage events), compared to never-treated zip codes, the use of distribution feeder length weights rather than the population-based weighting detailed in Section 4.1, and the use of a discrete treatment variable that denotes if a zip code experienced a PSPS outage in a given month, in place of the continuous outage intensity measure employed in Equation (1).

We provide assurance against the critiques raised in the case of two-way fixed effects estimates of DID with heterogeneous treatment (e.g., Goodman-Bacon (2021); Callaway and Sant'Anna (2021); de Chaisemartin and d'Haultfoeuille (2022a,b)). Reassurance against bias is the finding that only positive weights are used in the treatment effect estimation using the Goodman-Bacon decomposition (Goodman-Bacon, 2021). In addition, the concerns associated with staggered treatment timing are mitigated because the largest and most intense outages occurred in a single month, October 2019; 76 percent of our treated zip codes were first and only subject to outages in this month. Finally, we employ the estimator established by de Chaisemartin and d'Haultfoeuille (2022a) that uses a binary treatment variable that can accommodate staggered treatment timing, an event-study specification with dynamic treatment effects, and multiple treatment events. We find that our conclusions are robust to the use of this alternative estimator. See Section A.8 for a detailed discussion.

5 Estimation of the VoLL

In this section, we construct a dynamic discrete choice model to estimate the value of electricity reliability, separate from the other benefits that a solar-only or solar-plus-storage system provides a household. We exploit variation in outages that explain differences in adoption of the two technologies to obtain a revealed-preference estimate of the value customers place on averting outages, the residential VoLL.

5.1 Model of the Dynamic Discrete Choice of Technology

Our model consists of households that do not already have a solar or battery system. Every month, they face a decision d: (1) do nothing, (2) adopt a solar system, or (3) adopt a solar-plus-storage system.¹³ We assume that households are rational and follow a decision rule that maximizes the expected discounted sum of payoffs from their decision. Payoffs depend on the state of nature, s, which includes: current ownership status, the current net-of-subsidy up-front investment costs of moving from no technology to one of the two technologies, $C_{1\rightarrow d}$, the annual electricity bill that depends on technology ownership, c_d , and the annual duration of outages, $Outage_{kWh}$. These state variables are stochastic, and the household has expectations for how they will evolve in the future, s'. The state variables enter the current-period payoff from making the adoption decision as follows:

$$\mathbf{u}(s,d,\epsilon) = \begin{cases} -c_1 + \epsilon & \text{if } d=1, \text{ no adoption} \\ -c_2 - \gamma_2 - C_{1\to 2} - \gamma_{1\to 2} + \epsilon & \text{if } d=2, \text{ solar} \\ -c_3 - \gamma_3 - C_{1\to 3} - \gamma_{1\to 3} + \varphi Outage_{kWh} + \epsilon & \text{if } d=3, \text{ solar+storage.} \end{cases}$$
(2)

Each household has to pay an annual electricity bill, c_s , which varies by year, and the three endogenous states of ownership: (1) no technology, (2) solar, or (3) solar-plus-storage. The household also faces an unobserved annual shock, equal to 0 when it does not own a solar panel, γ_2 when it does own a solar panel, and γ_3 when it owns a solar-battery system. These costs or benefits capture, for example, an unexpected household shock that results in a higher or lower annual electricity bill, annual unobserved maintenance costs, or the warm glow from producing one's own power.

If the household adopts, it pays the current net-of-subsidy up-front cost, $C_{1\rightarrow d}$, and

¹³If a household adopts a system, then we model this as a terminal decision: we do not allow solar households to adopt a storage add-on or remove an adopted system. In the estimation, we set the payoff from changing states after adoption as prohibitively costly, and in the dataset, we only include single-family homes that do not yet have a solar or solar-plus-storage system. We think this simplification is reasonable given that storage add-ons are relatively infrequent during our sample period and also do not appear to respond to outages (Appendix Section A.3) and that we do not observe system removals in our data.

moves from owning nothing to its new state of ownership.¹⁴ The household also faces an unobserved adoption shock, $\gamma_{1\to d}$, which captures any technology-specific unobservable fixed costs or benefits, such as the cost of finding an installer or the initial warm glow from purchasing the system.

Avoided power outages enter the model as a unique benefit of adopting solar-plus-storage. The household considers the avoided kilowatt-hours of outage, $Outage_{kWh}$, valued at the residential VoLL, φ . Outages are measured as the rolling sum of outage kilowatt-hours experienced in the zip code in the prior 12 months.¹⁵ The outage hours are converted to outage kilowatt-hours by multiplying by the residential average electricity use per hour. The parameter estimate φ then provides a household's per-kilowatt-hour WTP to avoid an outage, which we convert and report in megawatt-hours, to be in a unit commonly used in electricity market design. Finally, in each year, households also face a random, unobserved shock, ϵ , that reconciles the differences in the model's optimal choice and the actual choices observed.

The household makes a decision each month, but it is based on the bill savings and expected outages at a yearly level. Our adoption data are at the zip-code level, which we expand to the household level using the number of single-family houses in the zip code (Integrated Public Use Microdata Series, 2020), less the number of existing solar and storage systems. In each month, we allocate households as adopters using the number of adoptions of solar and solar-plus-storage systems listed for the zip code. We are implicitly assuming that all households are the same within a zip code.

In addition to the current-period payoff (Equation (2)), the decision also depends on the expected future payoffs, which include the option of waiting to invest, the value of which arises from uncertainty in future costs and benefits. We account for household expectations in how the technology-specific investment costs, electricity bills, and annual kilowatt-hours

¹⁴Once a system is adopted, it is an absorbing state, with no future decisions to revisit.

¹⁵Note, when estimating the transition probabilities, we use yearly data such that household expectations are based on year-to-year variation.

of power outages, $s = \{c_d, C_d, Outage_{kWh}\}$, will change over time, following transitions governed by the probability density function $f(s', \epsilon'|s, \epsilon, d, \theta)$. The future periods are discounted at the discount factor β . In the estimation, we set β at the annual discount factor estimated from solar adoption in De Groote and Verboven (2019): 0.869 or an annual discount rate of 15 percent.¹⁶

With the state transition probabilities and the discount factor, we can express the expected discounted value of the adoption decision as the unique solution to the Bellman equation:

$$V(s,\epsilon) = \max_{d} \left[u(s,d,\epsilon) + \beta \int_{s'} \int_{\epsilon'} V(s',\epsilon') f(s',\epsilon'|s,\epsilon,d) d\epsilon' ds' \right].$$

Following Rust (1987), we adopt the conditional independence assumption: the unobserved shock is independent over time and conditional on the state variables but the future state is independent of the unobserved shock, such that the state transition can be factorized as $f(s', \epsilon'|s, \epsilon, d) = f(s'|s, d)g(\epsilon'|s')$. The unobserved shock would capture, for example, after learning from a program on the impacts of climate change, the altruistic satisfaction of owning solar panels might increase. This satisfaction might increase with the price of panels but would not lead to an increase the price of the panels themselves.

Under the assumption that ϵ is independent and identically distributed with a Type I Extreme Value distribution, the Bellman equation becomes:

$$V_{\theta}(s,\epsilon) = \max_{d} [v_{\theta}(s,d) + b\epsilon(d)]$$

where θ represents the parameters to be estimated, that is, those governing the state transition probability densities, the unobserved costs, and the VoLL. And v_{θ} is the fixed point of $v_{\theta} = \Gamma(v_{\theta})$, where Γ_{θ} is a contraction mapping (Rust, 1987):

¹⁶We note that when using a larger discount factor, we cannot replicate the data as well as when using the discount factor estimated in De Groote and Verboven (2019). Our choice to use a 15 percent discount rate is also in-line with the preliminary estimates of (Bollinger et al., 2023), that California households have discount rates of 10–19 percent.

$$\Gamma_{\theta}(v)(s,d) = u(s,d,\theta) + \beta \int_{s'} b \log \sum_{d'=1}^{3} \left[\exp\left\{\frac{v_{\theta}(s',d')}{b}\right\} \right] f(s'|s,d) \mathrm{d}s'$$
(3)

with scale parameter, b, from the extreme value distribution of ϵ , which we normalize to 1 (equivalent to \$1,000). The extreme value distribution of the error ϵ gives us the multinomial-logit, closed-form solution of the choice probabilities, given each choice's value $v_{\theta}(s', d')$.

In a first stage, we estimate a subsample of the parameters—the first-stage parameters, $\theta_{1^{st}}$ —which are found in the transition probability density function, $f(s_{t+1}|s_t, \theta_{1^{st}})$, for each of the state variables: the annual electricity bill, the technology-specific investment costs, and annual kilowatt-hours of power outage, $s = \{c_1, c_2, c_3, C_2, C_3, Outage_{kWh}\}$. We assume that households make predictions for the future values of these state variables based on their current levels and how they changed in the past.¹⁷ For each, we assume these variables evolve with an AR(1) process, with a drift parameter $\alpha_{0,s}$, slope coefficient, $\alpha_{1,s}$, and normally distributed noise with standard deviation σ_s . depicts how predictions compare to the data. Specifically, each state variable transitions according to:

$$s_t = \alpha_0 + \alpha_1 s_{t-1} + \sigma \varepsilon. \tag{4}$$

We assume the state transition probabilities are independent of each other and estimate $\theta_{1^{st}} = \{\alpha_{0,s}, \alpha_{1,s}, \sigma_s\}$ separately for each of the six state variables. For each state variable, we use data across all Z zip codes and T years, to find the $\theta_{1^{st}}$ that maximizes the likelihood:

$$L_1(\theta_{1^{st}}) = \prod_{z=1}^{Z_z} \prod_{t=1}^{T_i} f(s_{t+1}^z | s_t^z, \theta_{1^{st}}).$$
(5)

These estimated transition probabilities, $f(s_{t+1}|s_t, \hat{\theta}_{1^{st}})$, form the expectations for how the future states will evolve. For the outage state variable, when a household has not experienced a PSPS outage in the previous 12 months, we set the expectation to be that future outages are also zero and only follow the AR(1) process after a household experiences a PSPS outage. This choice for the expectation operator allows us to model the difference in

¹⁷We use data at the annual level to estimate the transition probabilities, so that the time interval for the probability of change maps to the time interval of the state variables.

expectations before and after PSPS outages in a parsimonious way. Before PSPS outages, we saw few outages and adoptions of batteries, which is in-line with households not expecting PSPS outages during the pre-period.¹⁸ After PSPS outages began to occur, we are assuming households without outages also do not expect outages, and discuss what this assumption means for our estimates in Section 5.2.¹⁹

In a second-stage, we estimate the unobserved costs/benefits of the decision and the VoLL, $\theta_{2^{nd}} = \{\gamma_2, \gamma_3, \gamma_{1\to 2}, \gamma_{1\to 3}, \varphi\}$, as described in the current payoffs, Equation (2). In the second-stage estimation the estimated first-stage parameters, $\hat{\theta}_{1^{st}}$ are taken as given and the likelihood of observing the zip-code solar and storage uptake is estimated using variation in outages. Using the data on T month-year decisions from N households, we estimate $\theta_{2^{nd}}$ by maximizing the second-stage maximum likelihood:

$$L_2(\theta_{2^{nd}}) = \prod_{i=1}^{N_i} \prod_{t=1}^{T_i} p(d_t^i | s_t^i, \theta_{2^{nd}}, \hat{\theta}_{1^{st}}).$$
(6)

The Extreme Value distribution of the error ϵ gives us the multinomial-logit, closed-form solution of the choice probabilities:

$$p(d|s,\theta) = \frac{\exp\frac{v_{\theta}(s,d)}{b}}{\sum_{d'} \exp\frac{v_{\theta}(s,d')}{b}}.$$
(7)

Apropos of its name, the nested fixed point algorithm (Rust, 1987), in maximizing the likelihood equation (6), for each candidate $\theta_{2^{nd}}$, the fixed point of the Bellman equation (3) is solved. Because in the second stage took the first stage parameters as given, in a third stage, we obtain consistent estimates of standard errors. In the third stage we use the full likelihood function that includes both the first and second stage. The full likelihood of

¹⁸Including the pre-PSPS events period is important to identify the value of solar adoption.

¹⁹Notably, when using an expectation operator in which all households have the same AR(1) process, our model often fails to converge and in subsamples in which it does, the estimates replicate the data poorly.

observing the adoption decision and state variable transitions is

$$L_f(\theta) = \prod_{i=1}^{N_i} \prod_{t=1}^{T_i} p(d_t^i | s_t^i \theta) f(s_{t+1}^i | s_t^i, \theta).$$
(8)

We run one iteration of minimizing the negative of the full log-likelihood, invert the Hessian matrix, and take the square root of the diagonal elements as our standard errors.

Finally, income is an important factor in the adoption of solar-plus-storage, as shown in Figure 5. To incorporate heterogeneity in income in the model, we estimate the model separately for subsamples based on quartiles of zip-code median income. The ideal would be to obtain an estimate of VoLL for every income level of households, however so many subsamples would be time consuming to estimate and regardless, we also do not have household-level data. As a result, for analytical tractability, we divide the sample into quartiles using zipcode median incomes. We note that this approach overlooks heterogeneity in household responses by incomes, first within a zip code, by only having median incomes, but also within a quartile, by obtaining one estimate for all zip codes in a quartile. Within an income quartile, households may vary by outage duration and electricity bills, but all households are assumed to be identical in their preferences.

5.2 Identification

Our identification strategy relies on observing adoptions of two similar technologies, which vary in both (a) cost and (b) the ability to avert outages, under exogenous variation in the exposure of outage intensity.

First, on costs, the decision to invest in a solar-only or a solar-plus-storage system involves weighing future bill savings against the up-front installation costs. As will be detailed below, both types of systems reduce a household's electricity bill, with a modestly larger reduction from solar-plus-storage. The modest additional bill savings of adding battery storage can only partly justify the higher price tag for a solar-plus-storage system. We account for bill savings as one driver of the adoption of solar-plus-storage using variation in annual bills and up-front installation costs, including spatial variation in bills due to solar irradiance in California's different climate zones. The observed differences in the adoption of solar-only, d = 2, versus solar-plus-storage, d = 3, in response to changes to the annual bill or up-front installation costs, identifies estimates of the unobserved costs and benefits of choosing one system over the other, which are interpreted in relation to the value (also unobserved) from not adopting any system, which we implicitly set to 0.

Important for our estimation is that only solar-plus-storage adoption, not solar-only, provides the additional benefit of allowing households to avert power outages. An observed increase in the adoption of solar-plus-storage, d = 3, in response to an exogenous increase in outages, $Outage_{kWh}$, identifies our parameter of interest, the WTP to avoid outages, φ .

Our identifying assumption is that outages are uncorrelated with other factors that impact the value of adopting solar-plus-storage conditional on income quartile. Although our DID controls for a zip-code-specific time trend and zip-code fixed effects, our structural model does not; however, we find that the cross-sectional variation driven by zip-code-specific differences is only a small driver of solar-plus-storage adoption (see Figure A7 and the associated discussion).

In addition to the conditional independence and additive separability assumptions of the nested fixed point algorithm (Rust, 1987), we also make the following assumptions. We are assuming that the solar-plus-storage system completely averts a household's expected outages. If households are averting less than the full outage, then we are underestimating their WTP for averting outages. In addition, it is possible that only a subset of storage projects in our data are provided subsidies.²⁰ Consequently, we may be overstating the subsidies provided for residential storage projects, which would bias our estimates downward. We compare the total storage capacity that filed applications in PG&E to the SGIP subsidy dataset and find that SGIP-funded capacity makes up 78 percent of total storage capacity

 $^{^{20}}$ California's Self-Generation Incentive Program, discussed in detail below, has funding limits, and a subset of subsidies are tied to household income.

in PG&E during our sample period, which thereby limits the extent of the bias. We also do not have data on other potential averting expenditures. For example, households could have purchased portable generators (Harris, 2023). However, to the best of our knowledge, there are no publicly available data that detail the universe of household generator adoption at the zip code level. Or, for example, households could be moving to different locations to avoid outages, an outcome that is outside the scope of this paper. By not observing these averting expenditures, we are implicitly assuming these households have zero WTP for outages, biasing our estimates downwards.²¹

Our estimation assumes that only PSPS outages in a household's own zip code affect adoptions. If neighboring zip codes affect adoptions, the bias could go in either direction. If neighboring zip codes have more outages, which in turn spur adoptions, our estimate is biased upward because we are understating the amount of expected outage kWhs factored into the decision to invest in solar-plus-storage. Alternatively, if neighboring zip codes have fewer outages, which in turn deter a household from adopting, our estimate is biased downward. Further, we identify our key VoLL estimate by comparing zip codes with PSPS outage events to those without. To the extent that households consider non-PSPS outages in their adoption decisions, and non-PSPS outages are correlated with PSPS outages, the lack of data on non-PSPS outages would bias our VoLL estimate upwards. However, as we note in Section 3, the PSPS outage events are large compared to historical non-PSPS outages and the difference-in-difference estimates show similar pre-treatment non-adoption of batteries for zip codes that eventually experienced PSPS outage events to those that did not. If other reasons exist for households that do not experience PSPS outages to expect outages, our estimates will be biased upwards, due to our modeling assumption that households with zero outages do not expect future outages (see Section 5.1). This assumption allows us to

²¹Another avenue through which households could power their homes during an outage is by using their electric vehicle (EV) batteries. Such vehicle-to-home (V2H) applications are emerging as EV manufacturers are expanding their capabilities, even allowing households to power their homes during an outage from a rooftop solar plus EV battery system (Coren, 2023). However, to the best of our knowledge, the potential use of V2H was limited during our sample period (Pacific Gas & Electric, 2018). To the extent that this was arising, our VoLL estimate would be biased downward.

include one state transition matrix to characterize decisions from both the pre-PSPS period, useful for identifying the unobserved costs of solar versus solar-plus-storage, as well as the post-PSPS period, useful for identifying the VoLL. In Appendix Section A.9.5, we consider alternative expectations on outages for those that experienced PSPS outage events.

Finally, it is possible that solar and storage retailers focused their door-to-door marketing efforts on areas recently experiencing outages. Due to data limitations, we are unable to completely rule out the presence of such marketing efforts.²² Our structural model assumes no differences in marketing practices. To the extent that informational barriers exist and marketing occurred only in areas with outages, then this would put upward pressure on our VoLL estimate. If there are informational barriers that limit adoption, it is possible that marketing efforts to target outage areas would elevate adoption of battery storage in these areas. To the extent that these households are better informed about the potential ability for storage to avert outages and they are responding to their exposure to past outage events, this serves as a better reflection of their WTP to avert future outages.

5.3 Data Inputs for the Discrete Choice Model

In this section, we summarize the data inputs used in the discrete choice model. We begin by describing the annual electricity bill and how it varies by the household's installed distributed-energy technology. We then detail how we establish estimates on the cost of solar and storage technologies.

Annual electricity bills

We use zip code-specific data on average monthly residential electricity consumption, the utility's rate schedule, and hourly solar output to compute the electricity bills of residential customers under the different technology choices for each year of our sample. The use of zip

²²It is worthwhile to note that the costs of customer acquisitions and marketing make up a large proportion of the costs of residential solar. In 2017, running up to the PSPS outage events in our sample, this led large retailers such as Solar City to end targeted door-to-door marketing (Wesoff, 2017). Regardless, in Section 6, we emphasize the importance of future research that accesses retail marketing data to assess the extent of targeted door-to-door marketing of solar-plus-storage systems.

code-specific electricity consumption captures the fact that electricity usage is driven in part by geographical location. The electricity bill of a customer who has a solar or solar-plusstorage system will vary over time at the hourly level. The difference in bills will depend on how much electricity is consumed and produced and at what time of day.

For the rate schedule of a customer without a distributed-energy technology, we use PG&E's E-TOU-C residential rate schedule, the default Time-of-Use (TOU) schedule that customers are shifted onto as PG&E moves its residential customers to TOU tariff schedules. For the rate schedule of customers with solar-only or solar-plus-storage systems, we use the Net Energy Metering (NEM) 2.0 retail rate policy that was in place in PG&E for our entire sample period. It includes mandatory TOU pricing and other bill components, such as a minimum bill and nonbypassable charges (Pacific Gas & Electric, 2021a,b).²³

To calculate solar output, we need a measure of solar irradiance. We take the geographical centroid of California's 16 Climate Zones and gather solar irradiance data from the NREL Multi-Year PSM Global Horizontal Irradiance data at these locations to permit geographical variation (NREL, 2021).²⁴ We use NREL's System Advisor Model and the solar irradiance data to simulate hourly solar output at each location. We match each zip code with its relevant Climate Zone.

For customers with solar-plus-storage systems, we use this approach to characterize hourly solar output. Under the NEM 2.0 TOU pricing tariff, the primary financial incentive for using the battery is to arbitrage off of the peak-to-off-peak TOU price differential. We develop an algorithm to model the charge and discharge operational decisions of the battery system. The battery is charged in hours with excess solar production in the mid-day off-peak hours and discharged in the evening peak hours to offset demand from the grid when the sun sets during peak hours. We assume a 10 percent round-trip efficiency loss of the battery

²³A minimum bill serves as a floor on a customer's bill and requires a NEM customer to have to pay a minimum amount per-day to cover the costs of maintaining the electric grid. Consumers face nonbypassable charges when they consume electricity from the grid. These charges cannot be offset by exporting excess solar to the electricity grid; rather, excess solar can only be used to offset energy charges.

²⁴California's Climate Zones were established to create energy efficiency standards and are based on energy use, temperature, weather, and other climatic factors (CEC, 1995).

system.

For electricity consumption, we use data on the average monthly consumption at the zip code-level to capture heterogeneity in usage across the regions of PG&E (Pacific Gas & Electric, 2023). To establish hourly electricity usage estimates, we use PG&E's 2017–2020 representative residential hourly load profile to establish a demand shape of a typical residential customer (Pacific Gas & Electric, 2021b). We apply this demand shape profile to the zip code-specific average monthly consumption values to create a data set that provides hourly electricity usage for each zip code over our sample period.

For the solar PV and battery storage system capacity values, we use the median capacity values observed in our sample. This yields a value of 5.4 KWs for solar and a battery storage system rated power capacity of 5 KWs.²⁵ Furthermore, the median energy capacity of the battery (in KWhs), when it is reported, is approximately two times the rated power capacity.²⁶

After having established the rate structure, consumption profiles, and solar and storage system characteristics for each zip code, we calculate the residential customers' hourly electricity bill and aggregate it to represent an annual electricity bill. We find that adding rooftop solar reduces the average annual electricity bill by 94%. This is in the range of estimates from other studies that find bill savings of approximately 90% (Gong et al., 2017). Adding battery storage reduces the electricity bill by 11 percent on average compared to a solar-only system.²⁷ This reduction is consistent with the findings in the literature that the bill-reducing value of a battery system is modest relative to its costs for residential consumers under current retail tariffs, suggesting other reasons for adopting this technology (e.g., resiliency and reliability value) (Fares and Webber, 2017; Barbose et al., 2021).

Rooftop solar adoption costs

²⁵Approximately 70% of all installed battery systems in the SGIP data lie between 4.7 and 5 KWs.

²⁶While our structural model separates zip codes by income quartile, we observe minimal differences in the median installed capacity sizes for solar PV and battery storage by income quartile. As a result, for analytical tractability, we assume uniform system sizes across zip codes.

²⁷See Figure A8 for a detailed illustration of the estimated bill savings by technology configuration and income quartile over our sample.

During our sample period, the only subsidy provided to rooftop solar systems is the federal income tax credit (ITC), which equals 30 percent of the project's costs in 2017–2019 and 26 percent in 2020 (U.S DOE, 2021).²⁸ For an estimate of the average solar cost and subsidy, we use reported system costs on non-third-party-owned residential solar systems in Go Solar California's (2020) Distributed Generation Interconnection data set.²⁹ We use this individual application-level data to compute the median monthly reported solar cost. This results in solar costs with an average of \$4.28/watt over our sample.³⁰ We apply the ITC to these values to estimate the solar subsidy. As expected, the solar costs and ITC subsidy values have declined over our sample.³¹

Solar-plus-storage adoption costs

We use data from California's SGIP (SGIP, 2020; Go Solar California, 2020). The data provide information on the system characteristics, customer class, and cost of battery systems installed and subsidies provided. We use the median monthly cost reported and subsidy received per kW. In 2020, the CPUC expanded the SGIP to include subsidies for communities affected by PSPS outages or households that live in areas prone to wildfire prevention outages. However, the implementation of these subsidies occurred after our sample period (TerraVerde Energy, 2020). In addition to the SGIP, households that install battery storage systems that are paired and charged with rooftop solar are eligible for the ITC of 30 percent in 2017-2019 and 26 percent in 2020 (IRS, 2017). Similar to the approach used to calculate solar costs, we apply the ITC to the storage capacity costs and add this to the storage

 $^{^{28}}$ We follow Borenstein (2017) and Pless and Van Benthem (2019) and assume that the ITC is fully monetized by the households. The credit is nonrefundable, so the customer needs to have enough tax liability to absorb it. However, households can carry over unused credit to the next tax year reducing the amount of any unused credit (U.S DOE, 2021). We may be overstating the benefits associated with the ITC. For our analysis, any overestimates on the subsidy provided to solar will symmetrically impact customers who adopt solar-only and solar-plus-storage systems. Our estimate of the VoLL is identified from the difference between the household utility from adopting solar versus solar-plus-storage.

²⁹Other studies have identified issues with reported system costs for third-party solar systems because they are installer-reported appraised values rather than actual prices households pay (Pless and Van Benthem, 2019). To avoid these possible data quality issues, we focus on non-third-party systems, which represent 70 percent of the observations in our data to establish estimates on the costs of a solar system.

³⁰This estimate falls closely in line with those reported in the literature (Barbose et al., 2021).

³¹See Figure A9 for a summary of solar capital costs and subsidies over our sample.

subsidy.

We find costs and subsidies in the range of \$1,618-3,145 per kW and \$896-1,779 per kW over our sample, respectively. Somewhat surprisingly, as shown in Figure A10, storage costs have increased over time. This is consistent with findings in other studies that suggest that this increase is driven by supply-chain constraints and value-based pricing (Barbose et al., 2021). Storage subsidies have declined over time because of the reduction in the ITC and the ratcheted nature of SGIP funding as storage enrollment increases (SGIP, 2020).

Figures A8–A11 depict the changes in the state variables over time and Figure A12 presents the predicted and actual values of our future state variables following the first stage estimation.

5.4 VoLL Estimates

We separately run the estimation by subsample, defined by quartile of zip-code median household income. Our estimate of VoLL is increasing by income quartile, ranging from \$3,451/MWh to \$6,809/MWh, averaging \$4,980/MWh (see Table 3).³² The literature has a broad range of residential VoLL estimates, from as low as \$50/MWh to as high as \$109,169/MWh, varying by country and estimation methodology (see Table A1). Most comparable in size to our estimates is the US meta-analysis by Sullivan et al. (2015) that includes 34 different data sets from various stated-preference surveys, ranging from \$1,444/MWh to \$6,555/MWh. Our revealed-preference estimates lie in the same general magnitude. Our estimates are larger than those of the only other available revealed-preference estimate of the residential VoLL at the writing of this paper, which has a central estimate of \$1,570/MWh (Harris, 2023). In his study, he uses data across the United States and documents an average outage duration of 5 hours across all counties. This contrasts with the PSPS power outages in California with outage events lasting between 15 and 70 hours on average for those affected (recall Table 1). This difference could point to the importance of outage length in

 $^{^{32}}$ The parameters from the first-stage transition probabilities and the other second-stage structural parameters are discussed in Appendix Table A5.

determining a household's WTP to avoid outages.³³

	In	Income Quartile Subsample				
	First	Second	Third	Fourth		
φ_{VoLL} (\$/MWh)	3,451 (60)	4,188 (65)	5,471 (134)	6,809 (42)	4,980 (83)	

Table 3: Estimated Value of Lost Load

Note: Value of Lost Load (\$/MWh) is the estimated φ in the dynamic discrete choice model. In parentheses are standard errors calculated from the Hessian matrix of the full log-likelihood function. The other estimated parameters from the discrete choice model are found in Table A5. Final column shows the average across the four income quartiles with a standard error calculated from the average of the variances.

In Appendix Section A.9.5, we provide estimates with alternative assumptions on what households expect future outages to be: (1) outages will remain the same as the current year with certainty, and (2) outages are expected to go to zero in the future. The case with certain constant outages results in estimates ranging from \$2,045/MWh to \$10,245/MWh, with an average of \$7,371/MWh, which is of similar magnitude to our main specification. The higher average VoLL estimate is driven by the fact that in our main specification, outages are expected to increase in the near future, and dissipate over time. With constant outages, a higher VoLL is required to justify investment. In the extreme optimistic case, in which a household expects outages to go to zero in the future, most of the estimates are larger with an average VoLL estimate of \$12,029/MWh. The estimates are considerably more variable across income quartiles and the estimates underpredict the actual solar-plus-storage adoptions, even with a VoLL estimate that is much larger than our main specification. This extreme case reiterates that the benefit of being able to avert outages is needed to justify the expense of battery adoption today.

Our estimate can be used to calculate the value of the lost electricity consumption of residential households during PG&E's outage events in 2018 and 2019. We take the estimated

³³The willingness to pay to avoid outages may be heterogenous over a number of dimensions including the length and timing of the outage, and whether there is advanced notification (Gorman, 2022). Future work is needed to quantify the extent to which VoLL varies along these dimensions.

kWhs households were unable to consume as a result of the outages in each zip code and multiply by the income-quartile-specific VoLL.³⁴ Our estimates suggest damages of at least \$406 million to residential customers alone for the foregone consumption value. The full cost of the outages would include various other factors such as the losses by commercial and industrial customers, property damage, and potentially the loss of life.

6 Conclusion

We examine the defensive expenditure of solar-plus-storage adoption to reduce the exposure to power outages in California. We exploit variation in exposure to hours-to-days-long power outages. Using a DID empirical methodology, we demonstrate that zip codes exposed to more intense power outages adopted more solar-plus-storage systems. Residential battery storage is a nascent technology, so although the absolute value of capacity additions was small in magnitude, in percentage terms, battery capacity increased considerably (45 percent in affected zip codes). We find substantial heterogeneity by median household income, with the largest effects arising in the highest income zip codes.

Our dynamic discrete choice model of solar-plus-storage adoption estimates a household's WTP to avoid outages, an essential parameter widely applied in the electricity sector. This model allows us to disentangle drivers of adoption: the large capital investment costs, the direct benefits of bill savings, and the value of averting future power outages. We permit the WTP to vary based upon a zip code's median household income and estimate values averaging \$4,980/MWh. In the context of California, our parameter estimates can be used to compare the relative cost of wildfire-prevention strategies, such as burying power lines and vegetation management, to the consumer benefits of avoided power outages. More broadly, our revealed-preference estimates serve as an important contrast to estimates in the

 $^{^{34}}$ More specifically, for each zip code and month, we estimate the total number of foregone kWhs by customer-outage-hours incurred by the average kWhs consumed. This number is multiplied by the zip code's income-quartile-specific VoLL estimate. We take the sum of these estimates over all zip codes in 2018 and 2019.

literature, which largely rely on stated-preference surveys.

After our sample period, California utilities made subsequent adjustments to their software, vegetation maintenance, and equipment to reduce the intensity of future PSPS outages (Pacific Gas & Electric, 2022). Given that PSPS outage events decreased and we find that averting power outages played a role in the adoption of solar-plus-storage systems, it is likely that some of these investments were overinvestments *ex-post*. This emphasizes the importance of having accurate forecasts and communication of the likelihood of future power outage events in order to avoid the potential for inefficient averting expenditures.³⁵

Our analysis provides several directions for future research. First, our data are limited because we do not observe individual household-level exposure to power outages or the universe of all averting expenditures (e.g., investing in a backup generator). Rather, we use zip code level information on the difference between solar-only and solar-plus-battery to infer responses to power outages. Individual household-level data would allow additional evaluation of heterogeneous effects by household characteristics. Second, our VoLL estimates include various frictions, such as credit constraints, that may limit lower-income households from adopting solar-plus-storage. Consequently, regulators should not extrapolate our estimates to implement broad strategies such as curtailing residential customers with lower VoLL estimates during periods of scarce supply. More direction in how to use VoLL estimates in curtailment decisions and the associated equity concerns is warranted from future research.

Third, we do not have access to data that evaluates the potential for targeted marketing of battery storage in areas that were exposed to PSPS outage events. An empirical evaluation of marketing and its implications on battery adoption is a fruitful area for future research. Fourth, we abstract from adding on storage to existing solar arrays in our discrete choice model for analytical tractability and because the majority of systems during our sample period were new solar-plus-storage systems. Going forward, opportunities for outage abatement can potentially come at a lower cost by adding batteries to existing solar

³⁵Molina and Rudik (2022) demonstrated the importance of accurate forecasting of hurricanes and find that this generates large social benefits due in part to more effective allocation of protective spending.

infrastructure. This could be further facilitated by changes in retail rate design that increase the private financial value of adding on battery storage to solar systems.

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Appendix

A.1 Recent Estimates of Value of Lost Load (VoLL) in the Literature

Surveying the most recent papers, Table A1 summarizes VoLL estimates from papers published between 2015–2022. For earlier papers: Schröder and Kuckshinrichs (2015) provide a survey of Value of Lost Load (VoLL) estimates from papers published 2004–2014 and Gorman (2022) provides a survey of meta-analyses that cover papers published 1948–2014.

Study	Country	VoLL Estimate (2020 USD/MWh)	Method
Woo et al. (2014)	Hong Kong	$21,\!834109,\!169$	Contingent Valuation
Kim et al. (2015)	South Korea	2,023-2,535	Contingent Valuation
Sullivan et al. (2015)	United States	1,444-6,555	Meta-Regression Analysis
Abrate et al. (2016)	Italy	$20,\!693\!-\!56,\!155$	Stated Choice Experiment
Castro et al. (2016)	Portugal	11,702	Production Function
Cohen et al. (2016)	${ m EU}$	170 - 7,549	Stated Choice Experiment
Ozbafli and Jenkins (2016)	North Cyprus	370 - 1,418	Stated Choice Experiment
Wolf and Wenzel (2016)	Germany	$10,\!332 - \!23,\!799$	Production Function
Shivakumar et al. (2017)	${ m EU}$	4,723 - 24,041	Production Function
Giaccaria et al. (2018)	Greece	$8,\!474\!-\!19,\!693$	Contingent Valuation
Hämäläinen (2018)	Finland	$4,\!655\!-\!23,\!632$	Contingent Valuation
Morrissey et al. (2018)	England	856 - 7,511	Stated Choice Experiment
Longo et al. (2019)	The Netherlands Portugal Estonia	$728-29,802 \\704-31,091 \\406-22,856$	Stated Choice Experiment
Alberini et al. (2022)	Nepal	50 - 149	Contingent Valuation
Broberg et al. (2021)	Sweden	49,541-74,311	Contingent Valuation
Carlsson et al. (2021)	Sweden	573-810	Contingent Valuation
Harris (2023)	United States	500-2,510	Revealed Preference

Table A1: Summary of Residential VoLL Estimates in the Literature, 2015-2022

Notes: VoLL estimates were adjusted by first converting to USD using the appropriate average exchange rate in the given reference year at https://www.exchangerates.org.uk/, then adjusting for inflation using the All Items in US City Average CPI Series (Seasonally Adjusted) from FRED. Estimates reported in dollar amounts per hour of outage were adjusted using an average hourly electricity consumption of 0.78 kW by households in any given hour. The Contingent Valuation and Stated Choice Experiments reflect stated-preference survey estimates. Production Function methods are macroeconomic models that assume that electricity is an essential input into production. The revealed-preference estimate uses purchases of portable generators.

A.2 Constructing Outage Intensity by Population Weights

Our primary treatment variable aims to capture the intensity at which a zip code was exposed to outage events. We use a measure that captures the residential-person-outage hours in each zip code and month. Figure 3 provides an illustration of our data and methods. We overlay the geospatial data of PG&E's distribution feeders (blue lines) with the Census's Zip Code Tabulation Areas (ZCTAs) (black lines).³⁶ We then match the PSPS outage events provided at the distribution feeder level to zip code level. This matching is complicated because a feeder can pass through multiple zip codes. For example, the red line highlights an individual distribution feeder that was on an outage. Consequently, for each feeder, we must establish a method to allocate residential-person-outage hours to each zip code it intersects.

Although we know the number of customers affected by an outage on each feeder, we do not know exactly where these customers are located along it. We employ a method from the geography literature that uses machine learning algorithms to project aggregated population measures to high-resolution geospatial data. We use the 2020 WorldPop gridded population dataset to project the population distribution across California on a 500-meter by 500-meter square grid (WorldPop, 2020). WorldPop uses the most granular census population data (i.e., block groups), projects additional land cover topology layers (rivers, elevation, forests, roads, etc.), the geography literature research on where humans live by land use type, and random forest machine learning models to project the census population onto a more granular scale.^{37,38}

The gray shaded squares in Figure 3 presents the 500-by-500 meter square grid of population estimates, where each square has a WorldPop cell estimate on population density. We use this data to allocate outage intensity to zip codes as follows. Suppose feeder *i* passes through j = 1, 2, ..., NWorldPop cells and $z = 1, 2, ..., \overline{Z}$ zip codes. Denote w_j as the population weight of a specific WorldPop cell. Let L_{ijz} denote the length of feeder *i* in WorldPop cell *j* in zip code *z*. For feeder *i*, we assign the following residential customer weight to zip code *z*:

$$W_{iz} = \frac{\sum_{j=1}^{N} w_j L_{ijz}}{\sum_{z=1}^{\overline{Z}} \sum_{j=1}^{N} w_j L_{ijz}}$$

³⁸For additional details, see Sorichetta et al. (2015), Gaughan et al. (2016), and Lloyd et al. (2017).

 $^{^{36}}$ We crosswalk postal zip codes in the Go Solar data set to ZCTAs and find that only 0.3 percent of zip codes do not match their corresponding ZCTA counterpart.

³⁷More specifically, we use the 2020 unconstrained top-down 1km resolution WorldPop data. These data provide an estimate on the population density as a point every 1,000 meters across California. We project the point-based data into a spatial measure using QGIS's Inverse Distance Weighting (IDW) Interpolation methodology to fill in the gaps between the points in order to assign a population weight to all locations in California. Using IDW Interpolation, population density at any location reflects a weighted average of nearby WorldPop population density points, where the weight is declining in distance. Using this methodology, we are able to establish a 500-meter by 500-meter spatial grid that allocates a population per pixel number to all locations in California.

For each feeder i, this method places more weight on zip codes with a higher WorldPop gridded population estimate along cells intersected by the distribution feeder. The weighting method equals 1 when it is summed across all z zip codes a feeder intersects. For each PSPS outage event and zip code in PG&E's territory, the feeder weight is used to allocate the number of residential customers affected and the number of residential-person-outage hours (i.e., residential customers affected times the number of outage hours). We use these measures to capture the intensity of outage event a zip code is exposed to in any given month.³⁹ Finally, we match this zip-code-based PSPS outage data set to the Go Solar California's (2020) data set that provides information on solar and solar-plus-storage adoption.

A.3 Different Outcomes of Interest

Figure A1 presents estimates from Equation (1) but with different outcome variables: (a) solar capacity from the adoption of solar-only systems, (b) solar capacity from the adoption of solar-plus-storage systems, (c) storage capacity from the adoption of solar-plus-storage systems, and (d) storage capacity added onto existing solar systems. Although solar PV adoption is much more prevalent than storage (as seen by the capacity in watts), evidence is limited of a distinct systematic increase in solar-only adoption in zip codes that experience outage events. The point estimates in the regression of storage add-on capacity are noisier after the outages, with only a single statistically significant positive coefficient six months after an outage event.

³⁹We also employ weighting methods that allocate customers along a feeder based on the percentage of a feeder's line length in each zip code it intersects. This assumes a uniform distribution of customers along a feeder. Our results are robust to this alternative specification, as shown in Table A3.



Figure A1: Impact of Outage Intensity on Solar and Storage Capacity (Watts)

(c) Storage Capacity (Both Solar & Storage)



Notes. The dependent variables reflect watts of installed capacity for (a) solar capacity on solar-only systems, (b) solar capacity on solar-plus-storage systems, (c) storage capacity on solar-plus-storage systems, and (d) storage capacity added onto existing solar systems. The coefficients are reported in the solid lines and are the estimates of β from our specification in (1) with quadratic zip-code-specific time trends. The shaded region reflects the 95 percent confidence intervals.

A.4 Decomposing Storage Adoption Response

We estimate the event-study specification in (1), but consider two alternative dependent variables at the zip code-month level: (i) the number of storage systems and (ii) the mean storage system capacity when battery storage investment occurs. This allows us to evaluate the extent to which the observed response to PSPS outage events are due to an increase in the number of systems adopted or a change in the configuration of those systems (i.e., the sizing of the battery systems). Figure A2 presents the results of both specifications. Using the number of storage systems adopted, we see a large and significant increase after being exposed to a PSPS outage event. In contrast, we find no evidence of a differential change in the sizing of the battery storage systems after being exposed to a PSPS outage event. These results suggest that the primary response to being exposed to a PSPS outage event is an increase in the number of solar-plus-storage systems rather than a differential change in the size of those systems.





Notes. Figure depicts estimates of β_k from our specification in (1), with the dependent variables adjusted to include the number of storage systems adopted and the mean storage capacity on observed systems, regressed on leads and lags of outage intensity and quadratic zip-code-specific time trends. The shaded region reflects the 95 percent confidence intervals.

A.5 Robustness of Event Study to Different Time Trends

Figure A3 presents the results of our specification in (1) with (a) no trend, (b) a linear trend, and (c) a quadratic zip-code-specific time trends. In each case, the distinct positive and statistically significant posttreatment effect persists. As we remove the flexible zip-code-specific trend, we observe a small pretreatment trend 8–12 months prior to the treatment. However, this effect is small in magnitude.



Figure A3: Impact of Outage Intensity on Storage Capacity (Watts)—Zip Code Time Trend

(c) Quadratic Zip Code Time Trend

Notes. The dependent variables reflect watts of installed storage capacity. The coefficients are reported in the solid lines and are the estimates of β from our specification in (1) with (a) no trend, (b) a linear trend, and (c) a quadratic zip-code-specific time trends. The shaded region reflects the 95 percent confidence intervals.

A.6 Heterogeneity by Different Subsamples

In the main paper, we examined subsamples by a zip code's median income. In Figure A4, we present results broken out by an Environmental Justice Index. We use California OEHHA's (2018) CalEnviroScreen 3.0 EJ metric that is calculated using 20 socioeconomic, demographic, health, and environmental indicators grouped into two categories: (1) pollution burden and (2) population characteristics.^{40,41} The EJ measure ranges from 0 to 100, where a higher number reflects a more disadvantaged community. Despite a statistically significant effect at various quartiles of the Environmental Justice metric distribution, Figure A4 illustrates that the treatment effect of PSPS outage events is largest in zip codes with the lowest EJ concern (i.e., lowest CES scores). Table A2 presents the coefficient estimates for the main specification in equation (1), the results by income quartile shown in Figure 5, and the results for the CES EJ measure in Figure A4.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Full		Income	Quartiles		(CalEnviroSc	reen Quartile	es
	Sample	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Month \leq -12	-0.0020	-0.0019^{*}	-0.0006	-0.0011	-0.0090**	-0.0024	-0.0024	-0.0022	-0.0011
	(0.0013)	(0.0010)	(0.0015)	(0.0021)	(0.0043)	(0.0026)	(0.0025)	(0.0015)	(0.0013)
Month -7 to -11	-0.0019	-0.0016	-0.0008	-0.0011	-0.0078**	-0.0024	-0.0021	-0.0021	-0.0006
	(0.0012)	(0.0015)	(0.0015)	(0.0020)	(0.0035)	(0.0021)	(0.0023)	(0.0018)	(0.0013)
Month -2 to -6	-0.0015	-0.0005	-0.0005	-0.0009	-0.0074*	-0.0034	-0.0009	-0.0017	0.0007
	(0.0011)	(0.0007)	(0.0011)	(0.0016)	(0.0044)	(0.0021)	(0.0022)	(0.0010)	(0.0008)
Month 0 to 2	0.0035**	0.0014	0.0015	0.0044	0.0043	0.0050**	0.0030	0.0014	0.0018*
	(0.0018)	(0.0014)	(0.0015)	(0.0031)	(0.0047)	(0.0020)	(0.0039)	(0.0019)	(0.0011)
Month 3 to 5	0.0102***	0.0034***	0.0034^{*}	0.0111***	0.0244^{***}	0.0145^{***}	0.0091^{*}	0.0046***	0.0076***
	(0.0025)	(0.0009)	(0.0019)	(0.0042)	(0.0068)	(0.0032)	(0.0050)	(0.0016)	(0.0022)
$Month \ge 6$	0.0025*	0.0002	0.0022	0.0033	0.0046	0.0034**	0.0025	0.0008	0.0026
	(0.0014)	(0.0014)	(0.0015)	(0.0025)	(0.0042)	(0.0016)	(0.0033)	(0.0014)	(0.0025)
Observations	68,094	16,692	16,614	16,692	16,614	17,004	17,004	17,004	17,004
R^2	0.4927	0.2877	0.3043	0.5152	0.5229	0.5376	0.4990	0.4257	0.3751
F-Stat	12.41^{***}	10.44^{***}	2.90^{*}	8.79^{***}	6.04^{***}	6.62^{***}	7.13***	6.04^{**}	56.90^{***}

Table A2: Event Study Regression Main Results and Heterogeneous Treatment Effects

Notes: Models presented are estimates of Equation (1) with quadratic zip-code-specific time trends. We bin the individual event month indicator variables, $1(t - T_z^* = k)$, into 6 groups: (i) $k \leq -12$, (ii) $-11 \leq k \leq -7$, (iii) $-6 \leq k \leq -2$, (iv) $0 \leq k \leq 2$, (v) $3 \leq k \leq 5$, and (iv) $k \geq 6$. We bin the treatment effects 6 months and after into a final group because this indicator variable coincides with the start of the Covid-19 pandemic for the largest PSPS outage events in September and October 2019. This partitioning allows us to clearly separate out the likely confounding effects of the pandemic on storage adoption. Column (1) reflects the binned coefficient estimates of the full sample. Columns (2)–(5) and (6)–(9) are the binned coefficient estimates on subsamples broken down by income and CalEnviroScreen (CES) quartiles, respectively. Cluster robust standard errors at the zip code are in parentheses. * p < 0.10, ** p < 0.05, *** p < 0.01.

⁴⁰The pollution burden measures exposure to ozone, $PM_{2.5}$, diesel PM emissions, drinking water contamination, pesticides, toxic releases, traffic density, cleanup sites, groundwater threats, hazardous waste, impaired water bodies, and solid waste sites. The population characteristics measure educational attainment, housing burden, linguistic isolation, poverty, unemployment, asthma emergency room visits, cardiovascular disease emergency room visits, and percent low-birthweight births (California OEHHA, 2018).

⁴¹We use the US census's crosswalk data file to crosswalk the CalEnviroScreen census tract-level data to the zip code level based on population weighting.



Figure A4: Impact of Outage Intensity on Storage Capacity by CalEnviroScreen Quartiles

Notes. The dependent variables reflect watts of installed storage capacity. The coefficients are reported in the solid lines and are the estimates of β from our specification in (1) with quadratic zip-code-specific time trends, and the sample is separated by CalEnviroScreen quartiles. The shaded region reflects the 95 percent confidence intervals. We use California OEHHA's (2018) CalEnviroScreen 3.0 environmental justice metric.

A.7 Additional Robustness Specifications

Table A3 presents several additional model specifications. For comparison purposes, column (1) provides the results from our main specification over the full sample. Column (2) considers the results of our analysis when we compare zip codes that were first and only subject to PSPS outage events in October 2019 (reflecting 76 percent of treated zip codes) to never-treated zip codes. This comparison focuses on the most intensely treated zip codes and does not have variation in treatment timing.

	(1)	(2)	(3)	(4)
	Main	Oct. 2019 Only	Length Weights	Outage Dummy
Month ≤ -12	-0.0020	-0.0024	-0.0021	-227.09
	(0.0013)	(0.0024)	(0.0013)	(280.65)
Month -7 to - 11	-0.0019	-0.0020	-0.0019	-276.53
	(0.0012)	(0.0020)	(0.0012)	(274.26)
Month -2 to -6	-0.0015	-0.0024	-0.0015	-313.48
	(0.0011)	(0.0022)	(0.0011)	(271.34)
Month 0 to 2	0.0035**	0.0057**	0.0035**	408.60
	(0.0018)	(0.0029)	(0.0018)	(288.57)
Month 3 to 5	0.0102***	0.0168***	0.0102***	$1.615.33^{***}$
	(0.0025)	(0.0044)	(0.0025)	(350.45)
Month > 6	0 0025*	0.0037	0.0026*	459 99
$10000011 \ge 0$	(0.0025)	(0.0031)	(0.0015)	(209.10)
01	(0.0014)	(0.0029)	(0.0013)	(308.10)
Observations	68,094	58,032	68,094	68,094
R^2	0.4927	0.4886	0.4920	0.4830
F-Stat	12.41^{***}	5.70^{***}	11.45^{***}	5.68^{***}

Table A3: Event Study Regression Robustness Results

Notes: Models presented are estimates of equation (1) with quadratic zip-code-specific time trends. We bin the individual event month indicator variables, $1(t - T_z^* = k)$, into six groups: (i) $k \leq -12$, (ii) $-11 \leq k \leq -7$, (iii) $-6 \leq k \leq -2$, (iv) $0 \leq k \leq 2$, (v) $3 \leq k \leq 5$, and (iv) $k \geq 6$. Column (1) reflects the binned coefficient estimates of the full sample. Column (2) reflects the results for the zip codes that were first and only treated in October 2019 compared to never-treated zip codes. Column (3) reflects the setting where outages at the distribution feeder level were allocated to zip codes based on the percentage of line length. Column (4) reflects the setting where the continuous Outage Intensity treatment variable is replaced by an indicator variable. Clustered robust standard errors at the zip code are in parentheses. * p < 0.10, ** p < 0.05, *** p < 0.01.

Column (2) demonstrates that our key conclusions hold, with a positive and statistically significant effect of the outage intensity measure on battery storage adoption in months 0–5 after the October 2019 PSPS events. These effects are larger than those identified in Column (1). There are no pretreatment trends. Our model predicts that this PSPS outage event increased storage capacity investment in the zip codes exposed only to the October 2019 PSPS outage events by an additional 106 percent compared to the setting where the October 2019 PSPS outage events did not occur. These results suggest that the October 2019 outage events and the affected zip codes were a key source for our estimated outage-driven storage investments using the full sample.

Column (3) presents the results of our main specification when we use feeder-length-based weighting to allocate distribution feeder-level outage data to zip codes rather than our WorldPop weighting method. This approach assumes a uniform distribution of customers along a feeder. Despite this simple approach, the results are closely related to those that arise using our population-weighting estimates.

Column (4) presents the results of our analysis when we define our treatment variable to be an indicator that equals 1 when a zip code has been exposed to a PSPS event. This specification reflects a standard difference-in-difference (DID) with a discrete treatment variable. We continue to find a positive and statistically significant treatment effect 3–5 months after the PSPS events, and no evidence of pretreatment trends. We use the coefficient estimates to predict the amount of storage capacity that was installed using the specification in Column (4). We compare this level to the amount of storage capacity that would have been installed in treated zip codes absent the outage events. Our model predicts that storage capacity in treated zip codes increased by approximately 55 percent as the result of PSPS outage events. We prefer our continuous treatment variable that reflects residential customer-outage-hours because it captures the considerable heterogeneity in the intensity of outage events over our sample.

A.8 Staggered DID

We revisit concerns that arise because our analysis has variation in treatment timing (see Table 1). Goodman-Bacon (2021) demonstrates that the staggered DID estimate is equivalent to the weighted average of all possible two-by-two DID estimators. Unless potentially strong assumptions are imposed on the nature of the treatment effects, it has been shown that this approach can lead the DID regression model to be misspecified and fail to identify the average effect of the treatment on the treated. In essence, this arises because already-treated units act as controls for groups treated later in the sample (Baker et al., 2022).

Importantly, we demonstrate in Table A3 column (2) that our key conclusions are robust when we compare zip codes that were first and only treated in October 2019 (76 percent of zip codes) to never-treated zip codes. This comparison is not subject to the key critiques that arise as a result of staggered treatment timing.

To understand the potential implication of the concerns raised in the literature on our main specification, we use the diagnostic tests developed by Goodman-Bacon (2021). This method isolates the DID estimate and weights for the two-by-two DID that uses already-treated zip codes as a control group for zip codes treated later in the sample. Goodman-Bacon's (2021) decomposition method focuses on the standard two-way fixed effects DID absent covariates, which can be represented by augmenting equation (1) as follows:

Storage Capacity_{zt} =
$$\gamma_z + \delta_t + \beta D_{zt} + \varepsilon_{zt}$$
 (A.1)

where D_{zt} is the zero-one treatment variable that equals 1 if a zip code z has ever experienced a PSPS outage and 0 otherwise. Although this does not reflect our fully dynamic event-study framework with flexible zip-code-specific time trends and a continuous treatment variable, we believe that the Goodman-Bacon decomposition approach is informative of the performance of our analysis and which two-by-two DID estimators are driving our primary findings. Furthermore, as shown in Column (4) in Table A3, our conclusions are robust to the use of a discrete DID specification. Goodman-Bacon (2021) decomposes the staggered DID estimate into three groups: (i) never treated, (ii) early treated (e.g., October 2018), and (iii) late treated (e.g., October 2019).

Figure A5 provides the results of the Goodman-Bacon decomposition using the specification in (A.1). The weights for each two-by-two DID comparison are provided on the x-axis, and each DID estimate is provided on the y-axis. The red line represents the overall DID estimator. Figure A5 demonstrates a two-by-two DID comparison between a treated and never-treated group that receives considerable weight in the identification of the overall DID estimate. This group reflects the October 2019 treated group compared to the never-treated zip codes. This is consistent with the fact that the majority of the treated zip codes in our sample (76 percent) were first (and only) treated in this month. Furthermore, these figures demonstrate that despite variability in the size of the DID estimate, the treated versus never-treated comparisons are all positive, as are their weights.

As documented by Goodman-Bacon (2021), the two-by-two estimators that can generate biased results are the ones that compare the later-treated to the earlier-treated group (represented by the triangles). Figure A5 demonstrates that these two-by-two DID estimates receive limited weight in the overall DID estimator. This helps defend our analysis against the concerns over bias in two-way fixed effects DID under heterogeneous treatment effects.

Table A4 provides detailed results of Goodman-Bacon decomposition. We present the average DID estimates across each group and their relative weights to clearly quantify how these two-by-two DID estimates contribute to the overall DID estimator. Table A4 demonstrates that the key driver of the overall DID estimator is the comparison of the treated and never treated. The comparison of concern, later versus earlier treated, receives only 2 percent of the weight of our DID estimator. This raises our confidence that the possible biases documented by the econometrics literature is not a key driver of our results.

We follow Goodman-Bacon (2021) and use the Decomposition Theorem to manually adjust the DID estimator by subtracting the components of the DID estimator that introduce the bias (i.e., subtract the later versus early treated comparisons). These results are presented in the Adjusted DID Estimate column in Table A4 and further illustrate that these two-by-two DID comparisons have a limited effect on our overall DID estimate.



Figure A5: Goodman-Bacon Decomposition—Discrete Two-Way Fixed Effects DID

Notes. This figure implements Goodman-Bacon's (2021) Decomposition Theorem for the two-way fixed effects DID specification in Equation (A.1). The x-axis provides the weights placed on each two-by-two DID estimator, and the y-axis provides the corresponding DID coefficient estimate.

	Overall DID	Average DID				
		Treated vs	Treated vs Earlier Treated vs. Later T		Adjusted DID	
		Never Treated	Later Treated	Earlier Treated	Estimate	
Storage Capacity	2,127.85	2,470.06	176.21	268.29	2,122.40	
Weights		0.85	0.13	0.02		

Table A4: Goodman-Bacon Decomposition—DID Estimates and Weights

In addition to diagnostic test such as the Goodman-Bacon decomposition, an emerging literature establishes estimators to deal with the biases that can arise in the presence of heterogenous treatment event study specifications with staggered treatment timing (e.g., Callaway and Sant'Anna (2021); de Chaisemartin and d'Haultfoeuille (2022a,b)). A key benefit of this approach is that unlike the Goodman-Bacon decomposition, we can estimate an event study specification similar to the main specification in our analysis. The frontier research in this area accommodates treatments that are binary, staggered, and non-absorbing states (i.e., repeated).

We use the estimator by de Chaisemartin and d'Haultfoeuille (2022a) that uses a binary treatment variable that can accommodate staggered treatment timing, an event-study specification with dynamic treatment effects, and multiple treatment events. This new specification allows us to evaluate the robustness of our empirical analysis and serves to complement our previous empirical analyses (i.e., via the Goodman-Bacon decomposition) that demonstrates that the potential biases associated with the staggered treatment timing are not driving our empirical results.

Figure A6 presents the results of the impact of PSPS outage exposure modeled as a binary treatment variable on battery storage capacity using the de Chaisemartin and d'Haultfoeuille (2022a) estimator. The results closely parallel the qualitative nature of the effects found in Figure 4 in our main specification. There is a sizable increase in battery storage adoption for zip codes that experience PSPS outage events, with the largest response arising 4 - 6 months following the event. The effects decrease in months 7 and 8 post PSPS outage, although they remain significant in this alternative specification. Finally, similar to our main analysis in Figure 4, we do not find any statistically significant pre-treatment effects.

Figure A6: Impact of Outage Intensity on Storage Capacity (Watts) - de Caisemartin and d'Haultfoeuille Estimator



Notes. Figure depicts estimates of regressing installed storage capacity on 8 leads and lags of a binary indicator for being exposed to a PSPS event using the de Chaisemartin and d'Haultfoeuille (2022a) estimator. Eight leads and lags are chosen because of the required symmetry between leads and lags with this estimator. Standard errors are clustered at the zip code level. The bars represent the 95 percent confidence intervals.

A.9 Discrete Choice Model Data Inputs and Results

A.9.1 Variation used in DID versus dynamic model

Our main DID specification includes zip code fixed effects and a quadratic zip-code-specific time trend, but our structural model does not. Our structural model assumes all households within an income quartile are identical, which begs the question of whether cross sectional variation across zip codes could drive adoption decisions. Figure A7 presents the results of the regression in Equation (1), removing the zip code fixed effects and zip code-specific time trends. The coefficients are larger before and after outages, however, proportionately, the cross-sectional variation across zip codes is only a small driver of adoptions (comparing Figure A7 to our main DID results, Figure 5).



Figure A7: Storage adoption, including cross sectional variation

Notes. Structural model does not include fixed effects for zip code or quadratic zip-code-specific time trends. Here we show adoptions that include this cross sectional variation.

A.9.2 Representative Consumer Figures









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Figure A11: Outage Hours Per Household



Notes. The solid line represents the average outage hours per household across all zip codes at the monthly level. The gray shaded area contains the 5th and 95th percentile of the distribution.

A.9.3 Parameter Estimates in the Dynamic Model

In the main paper, Table 3 shows estimates for our main parameter of interest, the VoLL, φ . Table A5 provides the estimates of all parameters, θ , estimated in the discrete choice model.

First, we discuss the first five parameters presented in Table A5, $\theta_{2^{nd}} = \{\varphi, \gamma_2, \gamma_3, \gamma_{1\to 2}, \gamma_{1\to 3}\}$, the second-stage structural parameters found in the flow utility (Equation (2)). These are estimated by maximizing the partial likelihood function, Equation (6), with standard errors from the full likelihood function, Equation (8).

The VoLL, φ , as described in the main text, gives households the benefit of averting outages from \$3,451/MWh to \$6,809/MWh. In addition to this parameter, we estimate that owning solar panels gives households an annual cost, γ_2 , of \$622-\$1,156 per year, which could represent unobserved costs of upkeep, but also reconcile the difference between our estimated bills and actual bills. Owning a solar-plus-storage panel results in an annual cost, γ_3 , of \$773- \$1,626 per year. Switching from no system to a solar system provides households with a one-time unobserved shock, $\gamma_{1\to 2}$, of costs from \$1,600 to \$3,000, and switching to a solar-plus-storage system results in a one-time unobserved shock ranging from costs of \$5,700 to benefits of \$23. These unobserved shocks could also be driven by measurement error in the cost to install a system; if we over predict the cost to adopt, the model will compensate by allowing a positive benefit from adoption. The VoLL is identified through observing adoption decisions made under variation in experienced outages. The other parameters are identified through observing adoption decisions under variation in the up-front costs over time and annual bills over time and space.

Second, we discuss the remaining parameters, $\theta_{1^{st}} = \{\alpha_{0,s}, \alpha_{1,s}, \sigma_s\}$, the first-stage parameters, those of the state transition matrices, for each state variable. These are estimates of Equation (4) and estimated from maximizing the likelihood function in Equation (5) with standard errors from the full likelihood in Equation (8). The time series of these variables are found in Figures A8 – A10. In Figure A12, we show the predictions for the future state of nature, using as inputs the current state and the parameters estimated in the first stage.

In the case of the annual bill without technology, c_1 , the positive coefficient on the slope coefficient α_{1,c_1} suggests expectations that it will increase over time. This is the same for the annual bill with solar α_{1,c_2} and the annual bill with a solar-plus-storage system, α_{1,c_3} , though solarplus-storage has much more uncertainty in the size of the shock, σ_{c_3} . The cost of installation of solar, C_2 , is mean-reverting, with a coefficient just less than 1, α_{1,C_2} , but with large uncertainty, σ_{C_2} . The cost of installation of solar-plus-storage, C_3 , is expected to increase over time, with a positive slope coefficient α_{1,C_3} , but with even more uncertainty, σ_{C_3} . Outages are also mean-reverting with a coefficient $\alpha_{1,Outage}$ just less than one.

A.9.4 Model Fit

Table A6 compares the actual adoptions to the model-predicted adoptions. Although the predictions do not pass the Chi-squared goodness-of-fit test, we nonetheless think the model performs well. We are able to predict the adoptions within tens of thousands across over 100 million monthhousehold decisions.

		Income Quar	tile Subsample	
	First	Second	Third	Fourth
φ_{VoLL} (\$/MWh)	3,450.83	4,187.98	5,470.54	6,809.49
, , , , , , , , ,	(60.16)	(64.55)	(133.97)	(42.27)
γ_2	1,156.31	1,034.13	669.42	622.44
	(6.19)	(4)	(6.56)	(0.19)
γ_3	1,626.3	1,544.24	1,065.88	773.07
	(9.72)	(4.53)	(0.92)	(0.41)
$\gamma_{1 \rightarrow 2}$	$1,\!691.12$	$3,\!376.57$	3,235.04	3,238.6
	(17.23)	(8.99)	(17.81)	(1.99)
$\gamma_{1 \rightarrow 3}$	5,743.79	-23.45	780.95	3,002.07
	(62.79)	(3.56)	(10.96)	(3.3)
$\alpha_{0,c1}$	0.05	0.05	0.05	0.05
	(0.002)	(0.005)	(0.007)	(0.001)
$\alpha_{1,c1}$	1.09	1.09	1.09	1.09
	(0.0005)	(0.003)	(0.006)	(0.0004)
σ_{c1}	167.55	167.55	167.55	167.55
	(2.63)	(1.75)	(12.33)	(1.31)
α_{0,c_2}	-0.0005	-0.0005	-0.0005	-0.0005
	(0.001)	(0.001)	(0.001)	(0.001)
$\alpha_{1,c2}$	1.08	1.08	1.08	1.08
	(0.001)	(0.004)	(0.003)	(0.001)
σ_{c2}	121.05	121.05	121.05	121.05
	(1.69)	(1.24)	(8.74)	(0.63)
α_{0,c_3}	-0.0004	-0.0004	-0.0004	-0.0004
	(0.002)	(0.003)	(0.006)	(0.001)
$\alpha_{1,c3}$	1.09	1.09	1.09	1.09
	(0.004)	(0.003)	(0.007)	(0.001)
σ_{c3}	111.28	111.28	111.28	111.28
	(1.53)	(2.27)	(2.91)	(0.89)
$\alpha_{0,C1}$	34.41	34.41	34.41	34.41
	(0.13)	(0.01)	(0.38)	(0.0023)
$\alpha_{1,C1}$	-1.11	-1.11	-1.11	-1.11
	(0.01)	(0.0002)	(0.023)	(0.0002)
σ_{C1}	285.44	285.44	285.44	285.44
	(3.95)	(4.43)	(3.56)	(15.19)
$\alpha_{0,C2}$	-4.76	-4.76	-4.76	-4.76
	(0.05)	(0.02)	(0.11)	(0.08)
$\alpha_{1,C2}$	1.33	1.33	1.33	1.33
	(0.0025)	(0.001)	(0.005)	(0.004)
σ_{C2}	154.05	154.05	154.05	154.05
	(2.27)	(2.23)	(4.06)	(3.2)
$\alpha_{0,Outage}$	14.58	14.58	14.58	14.58
	(0.23)	(0.21)	(0.19)	(0.02)
$\alpha_{1,Outage}$	0.99	0.99	0.99	0.99
	(0.01)	(0.01)	(0.01)	(0.0002)
σ_{Outage}	43.91	43.91	43.91	43.91
	(0.26)	(0.12)	(0.05)	(0.03)

Table A5: All Parameter Estimates in the Dynamic Discrete Choice Model

Note: This table is an extension of Table 3 from the main text, presenting all (first-and second-stage) estimates from the dynamic discrete choice model. In parentheses are standard errors from the square root of the diagonal of the inverse Hessian matrix of the full log-likelihood function.



Figure A12: Time Series of State Variables, Actual and Predicted

Notes. Mean and 95% confidence intervals of our first stage predictions alongside the actual data.

Table A6:	Actual	versus	Model-F	redicted	Decisions,	Household-Month	Counts

	Income Quartile Subsample					
	First	Second	Third	Fourth		
Actual						
No adoptions	$10,\!379,\!370$	$21,\!441,\!913$	$30,\!486,\!359$	$39,\!865,\!274$		
Solar-only adoptions	$23,\!419$	43,868	$67,\!379$	70,671		
Solar-plus-storage adoptions	419	1,051	2,465	3,775		
Predictions from main specification						
No adoptions	$10,\!377,\!018$	$21,\!427,\!967$	$30,\!470,\!404$	39,827,306		
Solar-only adoptions	$25,\!972$	56,030	81,721	$108,\!687$		
Solar-plus-storage adoptions	218	2,835	4,078	3,727		
χ^2 p-value	0	0	0	0		

Note: Actual compared to predicted adoptions by zip code quartile of income using the assumptions in the main specification. The first panel contains the actual adoptions, the second panel contains the adoptions predicted from the model.

A.9.5 Structural Model Robustness: Alternative Outage Expectations

The estimation requires an assumption on what households expect future outages to look like. In our main specification, we are assuming that households that have experienced PSPS outages expect that future outages will progress as they have in the past following a stochastic AR(1) process. In an alternative case, we show the estimates when outages are assumed to remain the same as the current outage state (i.e., in the month of decision, the outages they had in the last 12 months dictate future outages with certainty). In this case, the transition matrix is simply an identity matrix of ones on the diagonal, zeros elsewhere. Table A8 shows that the estimates are larger than our main specification, but follow the same general pattern of increasing by zip-code median income quartile and the fit is similar to our main specification with stochastic outages.

We also examine the case in which households expect no outages in the future. Regardless of current outages, households expect next period's outages to be zero with certainty. In this case, the first column of the transition matrix are ones. Table A7 shows that the average VoLL estimate is considerably higher, but varies much more across income quartiles than our main specification and when we assume expected outages are certain and constant. Table A8 highlights that we predict few adoptions of batteries in this case and fit the observed data poorly. This extreme case highlights the need to include electricity reliability when justifying the costly expenditure of residential battery storage.

		Income Quartile Subsample						
	First	Second	Third	Fourth				
Outages expected to remain same, with certainty								
φ_{VoLL}	2,045	7,167	10,245	10,028	$7,\!371$			
	(343)	(44)	(80)	(69)	(181)			
Zero outages expected in future								
φ_{VoLL}	52	$23,\!568$	7,513	$16,\!982$	$12,\!029$			
	(232)	(35)	(282)	(32)	(184)			

Table A7: Value of Lost Load: Alternative Assumptions on Expectations

Note: Estimates under different assumptions for expectations: that outages remain the same in the future or revert to zero in the future. When households have no expectation of future outages, then the WTP to avoid the current period's outages are large, but as show in Table A8, but less able to replicate the data.

	Income Quartile Subsample				
	First	Second	Third	Fourth	
Actual					
No adoptions	$10,\!379,\!370$	$21,\!441,\!913$	$30,\!486,\!359$	$39,\!865,\!274$	
Solar-only adoptions	$23,\!419$	43,868	$67,\!379$	$70,\!671$	
Solar-plus-storage adoptions	419	1,051	2,465	3,775	
Outages expected to remain same, with certainty					
No adoptions	$10,\!379,\!829$	$21,\!428,\!451$	$30,\!482,\!656$	$39,\!823,\!207$	
Solar-only adoptions	23,008	57,019	72,909	$107,\!651$	
Solar-plus-storage adoptions	371	1,362	638	8,862	
χ^2 p-value	0.0017	0	0	0	
Zero outages expected in future					
No adoptions	$10,\!378,\!842$	$21,\!438,\!696$	$30,\!479,\!786$	$39,\!835,\!473$	
Solar-only adoptions	24,319	48,002	$74,\!649$	$103,\!604$	
Solar-plus-storage adoptions	47	134	1,768	643	
χ^2 p-value	0	0	0	0	

Table A8: Actual Versus Predicted: Alternative Assumptions on Expectations

Note: Actual compared to predicted adoptions by zip code quartile of income using alternative expectations. The second is that outages remain the same as the current period, with certainty, and the third panel is the expectation that the future will not have outages. The third panel demonstrates the importance of future outage avoidance in explaining observed battery adoption.