Smoothing the Green Transition: Which Battery Locations Provide the Greatest Returns to Renewable Generation in California

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Abstract

California's renewable portfolio standard requires a rapid de-carbonization of the state's electricity supply by 2045. Despite renewables' falling fixed costs, increased reliance on intermittent, primarily solar, generation creates two challenges for California's grid operator. First, maximum solar generation does not coincide with peak demand during the day. Second, locations with the greatest generation potential are distant from the state's demand centers. The spatial and temporal mismatch between renewable supply and demand increases the frequency of line congestion, causing localized curtailment despite the willingness to pay elsewhere. Utility-scale storage promises to mitigate the inefficiencies of intermittent generation by allowing owners to arbitrage electricity across time and space. My research investigates whether batteries operating in California's wholesale electricity market have increased the productivity of renewables, indicated by reductions in curtailment, and whether these impacts varied with batteries' location. I find that the marginal MWh of electricity used to charge batteries at noon in California resulted in a 0.5 MWh reduction in solar curtailment, which was largely driven by storage capacity additions near solar generators.

1 Introduction

Motivated by the mounting damages caused by global climate change and falling fixed capital costs, electricity markets are rapidly transitioning to renewable generation; however, increased reliance on variable renewable energy has challenged grid operators' ability to balance supply and demand. Solar and wind generation peak at midday and overnight, respectively, when demand is relatively low and often supply in excess of the grid's transmission capacity, forcing operators to curtail their output. To transfer cheap, carbon-free electricity between peak production and demand periods and store generation surpluses when the grid is congested, governments have offered generous investment incentives for utility-scale storage, particularly lithium-ion batteries. Despite the extensive theoretical literature examining the temporal impacts of electricity arbitrage on wholesale prices and emissions[1], it remains unclear whether batteries increase renewable generation or if their ability to do so depends on their location. In this paper, I ask if the growth in battery capacity increased the utilization of renewable generators, indicated by reductions in curtailment, and if so, which battery locations provide the greatest returns to renewable generation, categorized generally as supply or demand-side sites?

This paper examines whether batteries and renewable generators are complements and, if so, whether this complementarity depends on batteries' location, commonly sited either with renewable generators or in population centers. Ideally, batteries shift both load and the supply of renewably generated electricity from peak to off-peak hours by arbitraging electricity between high and low price periods. However, constraints imposed by the transmission infrastructure create trade-offs between renewable supply and demand-side batteries.

The literature has established that batteries increase the value of electricity supplied to the market when they charge, but has abstracted from whether charging affects the productivity of renewable generators and the role of their relative locations in the grid. de Sisternes, Jenkins, and Botterud (2016) and Karaduman (2021) provide theoretical evidence

[1] see Butters, Dorsey, and Gowrisankaran (2025), Linn and Shi (2019), and Karaduman (2021)

that energy storage increases the utilization of renewable generators in markets with higher curtailment risk; however, Butters, Dorsey, and Gowrisankaran (2025) and Linn and Shi (2019) point out that the complementarity between renewables and storage depends on the correlation between demand and renewable supply and weakens when generators are less demand responsive, respectively. To highlight the importance of location, my theoretical model introduces a novel representation of a wholesale electricity market in which renewable generation occurs exclusively in a demand-poor region, making the dispatch of clean, zero marginal cost electricity dependent on transmission capacity. In this setting, supply-side batteries are better situated to increase renewable generation when the grid is congested by localized supply gluts. Despite supply-side batteries' greater propensity to reduce curtailment, demand-side storage offers larger cost savings on days when load is excessively high by offsetting peak levels of thermal generation.

I study batteries in California, where storage and solar generation capacity have grown expeditiously to meet the state's renewable portfolio standards (RPS), which mandate the decarbonization of the electricity supply by 2045[2]. Despite the rapid adoption of renewables, electricity generation directly accounted for 11% of California's emissions in 2022[3] due to the continued reliance on natural gas to meet net demand. Solar generation is not only unable to respond to changes in demand, but also synchronous, often producing in unison beyond the grid's transmission capacity. Concentrated in California's rural Central Valley and southern desert, the state's photovoltaic arrays rely on high-voltage transmission lines to transport electricity to the coastal cities. Localized gluts in solar output are often curtailed to avoid damaging the grid, reducing the productivity of California's renewable generators.

Due to the recent and limited adoption of utility-scale storage outside of California, few studies have empirically examined the impacts of electricity arbitrage and none have considered its effects on curtailment. Using publicly available generation and load data provided by the California ISO (CASIO) and batteries' capacity, location, and first month of oper-

[2]https://www.gov.ca.gov/wp-content/uploads/2023/05/CAEnergyTransitionPlan.pdf
[3]https://ww2.arb.ca.gov/ghg-inventory-data

ation recorded in the Energy Information Administration's (EIA) 860 Survey, I investigate whether the increase in electricity consumption from charging batteries lead to meaningful reductions in solar curtailment at midday. Since charging behavior is non-random and related to unobservable factors that also influence curtailment, I use the level of installed storage capacity as an instrument for the energy consumed by batteries in a two-stage least squares framework. I find that from 2021 through 2024 in California, the marginal MWh of electricity used to charge batteries at noon resulted in a 0.5 MWh reduction in total solar curtailment.

Some attention has been paid to the spatial extent of batteries' impacts. Kirkpatrick (2025) finds that the effect of an increase in storage capacity on prices at neighboring nodes in the CAISO market is highly localized. My theoretical model supports this result, which describes how congestion creates heterogeneity in the effects of electricity arbitrage by supply and demand-side batteries. To investigate whether the effect of charging on solar curtailment differed between renewable co-located and demand-centered batteries, I exploit both the type of curtailment affected and the variation in the location of storage capacity installed in California over time. The CAISO records two different types of curtailment, local and system. Local curtailment occurs when a localized supply glut exceeds the transmission capacity of nearby lines, implying that only batteries proximal to generators can absorb the excess. Conversely, a grid-wide generation surplus causes system curtailment, which is affected by increased demand anywhere in the grid. I also compare changes in total solar curtailment during the early phase of battery adoption, when storage capacity was mixed between California's renewable generating region and its coastal cities, to the latter half, when batteries were predominantly co-located with solar. I find that the significant decrease in total solar curtailment was driven by reductions in local curtailment in the latter half of the sample, indicating that co-located batteries alleviated congestion that often constrains the transmission of electricity generated by renewables.

If California intends to meet its RPS, investments in rural solar farms in the central valley

and southern desert will require complementary investments in transmission. Federal and state governments are banking on utility-scale storage, particularly lithium-ion batteries, to increase renewable generation and substitute for expensive, bureaucratically cumbersome transmission line upgrades by offering Investment Tax Credits (ITC), setting procurement targets, and offering upfront rebates. These policies aim to increase the productivity of renewable generators and enhance grid reliability, but have not directly considered which locations are best suited to do so, instead deferring to private owners' decisions based on siting costs and arbitrage profit potentials.

After the passage of the Inflation Reduction Act in 2022, standalone batteries now qualify for the Federal ITC, which previously only applied to storage investments paired with solar generators[4]. In California, the Self Generation Incentive Program (SGIP) was initially designed to increase grid reliability but has since been expanded to technologies that reduce greenhouse gas emissions, allocating a majority of its funds to energy storage projects after 2016[5]. Despite its redirection, SGIP rates are lower for batteries paired with renewable generators that claim the Federal ITC and decrease with storage capacity[6]. Other states also offer rebates and tax incentives to achieve storage procurement targets. Most notably, New York aims to add 6 GW of storage capacity by the end of the decade, of which at least 30% is planned to be installed in New York City, where batteries are better situated to offset emissions from peaker plants[7]. Despite their ability to shave peak load and emissions, due to the physical constraints of the grid, batteries in demand centers are less able to increase the productivity of renewable generators and substitute for transmission upgrades.

California's commitment to decarbonize its electricity supply by rapidly installing renewable generation capacity hinges on complementary investments in energy storage. This paper demonstrates that the complementarity between batteries and solar generators depends on

[4]https://www.powerflex.com/blog/battery-storage-incentives-by-state

[5]https://sgipsd.org/background

[6]https://www.selfgenca.com

[7]https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program/Developers-and-Contractors/Bulk-Storage-Incentives

their relative locations in the grid. When congestion constrains the delivery of renewably generated electricity, supply-side storage is better situated to prevent curtailment. Despite this advantage, demand-side storage saves grid operators the exorbitant cost of dispatching peaker thermal plants when demand spikes. To wean off fossil fuels while promoting investment in renewable generation, California's storage policies must determine a spatial allocation of battery capacity that meets both objectives, weighing the trade-offs of siting storage either with renewables or with demand.

2 Background and Data

2.1 Utility-Scale Battery Storage in California

Spurred by the state's electricity storage mandate and generous subsidies, utility-scale battery capacity in California has grown from about 240 MW at the beginning of 2020 to just under 12,000 MW by the end of 2024, depicted by the red step function plotted in Figure 1. The current level of installed battery capacity is about one-third of average peak demand during summer evenings, around 36,000 MW[7]. The discrete monthly trend in cumulative battery capacity observed in the Energy Information Administration's (EIA) 860 Survey, which records batteries' nameplate capacity and first month of operation, does not accurately portray the true rate of storage additions. In reality, large batteries are composed of individual cells that turn on gradually, resulting in a more continuous increase in operating capacity over time. I address this inaccuracy in my empirical method to avoid over-attributing storage capacity to the earlier half of the first operating months.

The quantity of electricity consumed and supplied by batteries has increased in step with the level of installed capacity. CAISO's Today's Outlook dashboard reports telemetric approximations of the realized five-minute, state-aggregate battery charge and discharge levels in MWh, plotted in black in Figure 1. When batteries charge, their output is negative

[7]See appendix Figure iii.

since they are withdrawing electricity from the grid. Conversely, batteries increase the supply of electricity when they discharge.

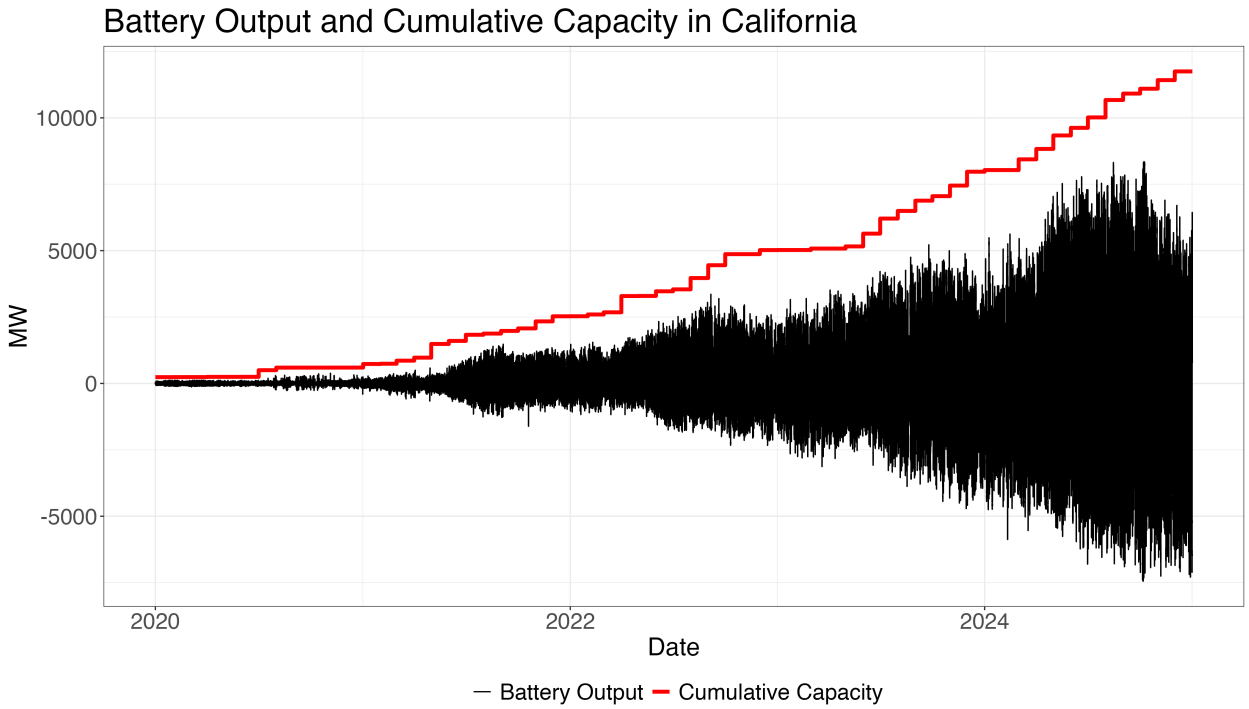


Figure 1: Cumulative battery storage capacity (MW) in California in red. Capacity additions are assumed to occur on the first day of the month in which the battery began operating. Batteries' nameplate capacity and first month-year of operation are recorded in the EIA-860 Survey 2024. Telemetric approximations of the five-minute, state-aggregate battery charge and discharge levels (MWh) in black from the CAISO's Today's Outlook Dashboard.

The average level of power flowing through batteries has increased drastically during peak charging and discharging hours, which occur consistently around noon and 8 p.m., respectively, as shown in Figure 2. Battery owners aim to maximize their arbitrage profits by buying and selling electricity in correspondence with the trend in hourly average wholesale prices plotted in Figure 3, beginning to charge around 8 a.m. and consuming the most at noon when prices are lowest. They gradually switch to discharging as prices climb to their daily maximum in the evening.

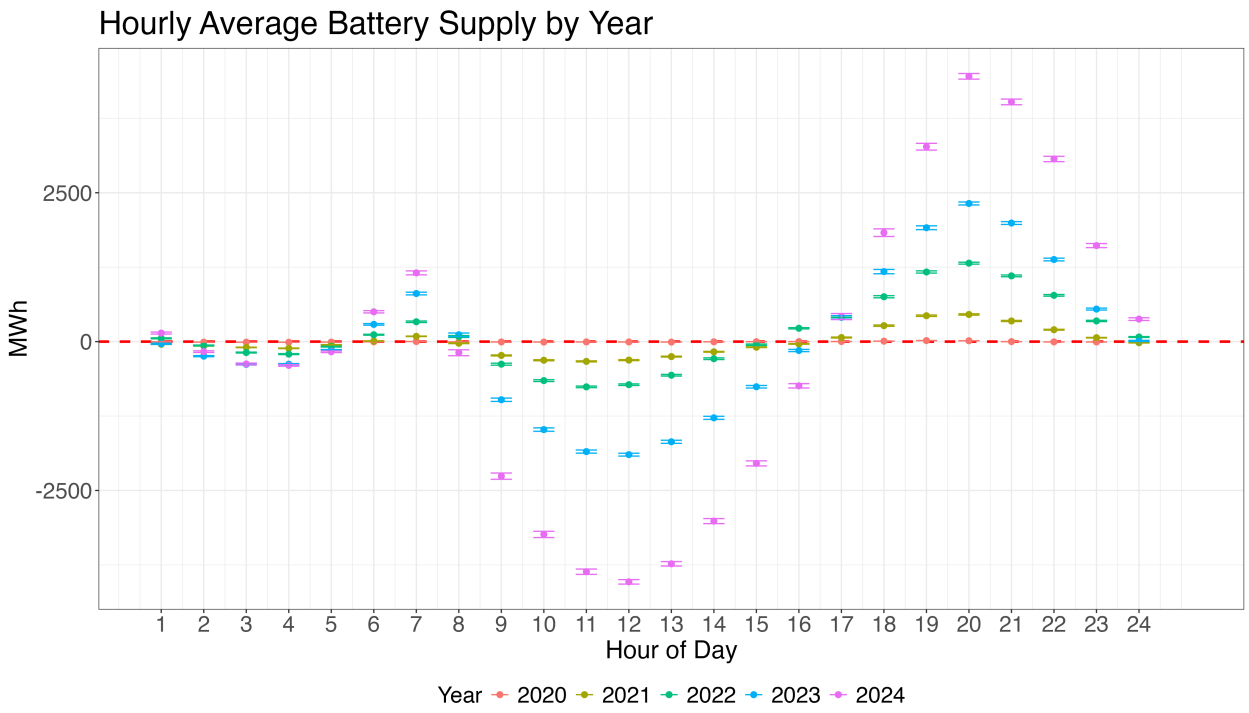


Figure 2: Hourly average battery supply (MWh) with 95% confidence intervals. Telemetric approximations of the five-minute, state-aggregate battery supply levels from the CAISO's Today's Outlook Dashboard.

2.2 Wholesale Prices

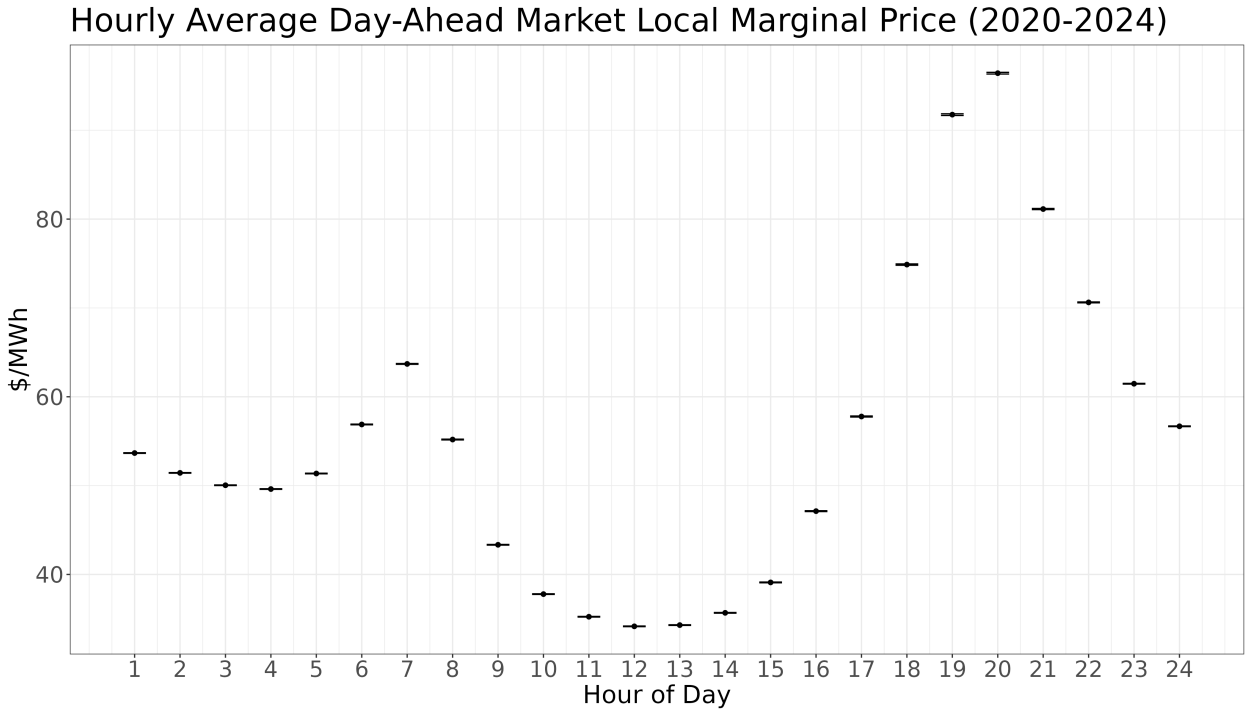


Figure 3: Hourly average Day-Ahead Market (DAM) Local Marginal Prices (LMPs) from 2020–2024 with 95% confidence intervals. Data from CAISO OASIS.

The diurnal solar cycle and residential electricity demand explain the hourly variation in average wholesale prices. Figure 4 plots average aggregate generation for each of the major fuel sources in 2024. In the morning, solar generation increases as the sun rises and peaks around noon when residential electricity demand dips into a midday trough, largely due to increased output from distributed rooftop solar panels. The resultant glut of zero marginal cost electricity depresses wholesale prices to their daily minimum. Taking advantage of low midday prices, batteries consumed just over 4,000 MWh of energy on average at noon in 2024, which was about 27% of the average solar output. Then, as solar generation declines and residential electricity demand increases in the evening, prices peak between 6 p.m. and 8 p.m., on average.

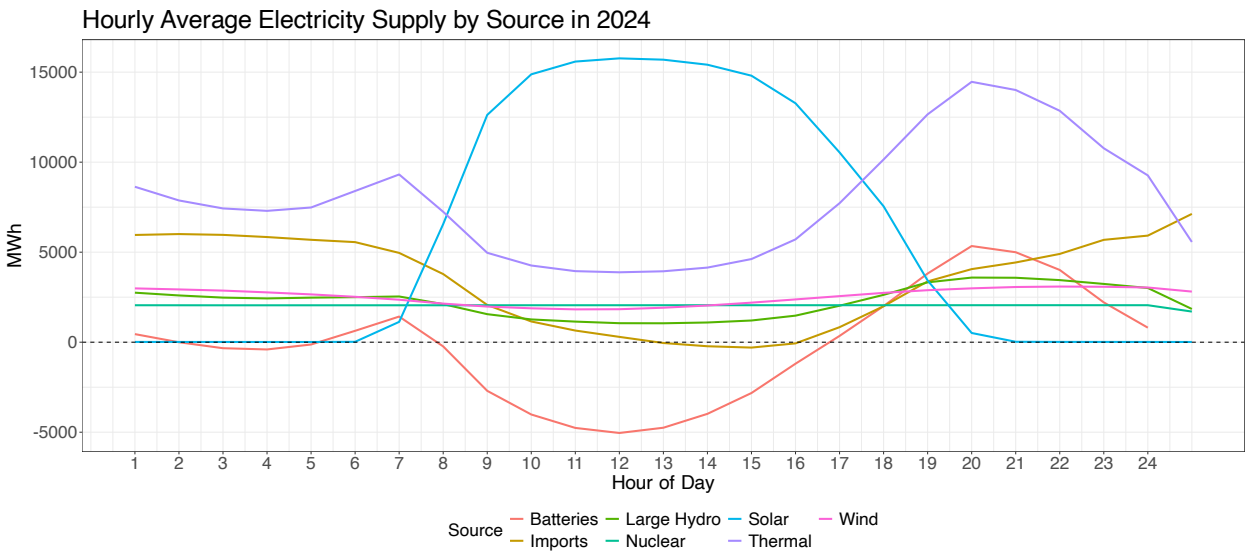


Figure 4: Hourly average aggregate supply of electricity (MWh) by fuel type across the hours the day in 2024 with 95% confidence intervals. Data from the CAISO's 2024 Production and Curtailment dataset.

The midday glut in solar generation causes wholesale prices to vary across space as well. Figure 5 illustrates the difference in the marginal cost of generating electricity at midday between Southern California's solar-rich region and the urban coast in 2020. The state's photovoltaic arrays are concentrated in the San Joaquin Valley and Mojave Desert, where the generation potential is highest, far from the coastal population centers. Electricity produced by rural solar generators relies on high-voltage transmission lines to reach the cities. When the power sent across these lines is lower than their capacity, electricity flows freely throughout the grid. Marginal increases in demand are supplied by the lowest marginal cost generator, regardless of its location, creating uniformity in local marginal prices (LMPs) across the state. However, if a spike in electricity supply or demand necessitates the transmission of more power than the physical limits of the lines, the grid becomes congested. Electricity produced at zero marginal cost by solar generators in the Central Valley may now be unable to reach where it is demanded. Higher marginal cost generators will be dispatched in the demanding region, raising prices there while prices in the valley remain low. The clear disparity between average LMPs in the rural solar generating region and the

coastal cities at midday indicates that congestion constrains the transmission of renewably generated electricity.

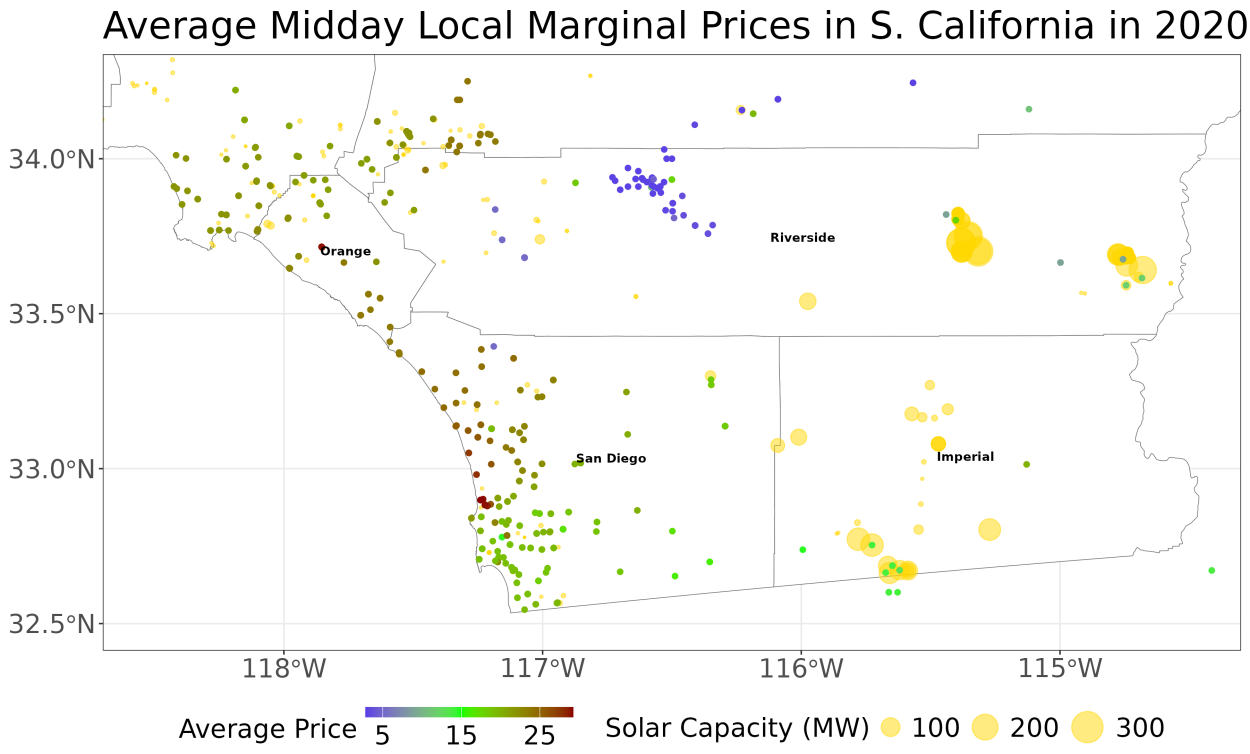


Figure 5: Average midday (10 a.m.- 2 p.m.) LMPs at each node in the CAISO market in southern California in 2020. DAM LMPs from the CAISO's OASIS.

Like other generators, batteries are transmission-constrained. When nearby lines are congested, the impacts of electricity arbitrage on generation and prices will depend on a battery's location in the grid. Supply-side batteries in the valley face transmission constraints when discharging during peak demand events; however, they will be unconstrained when charging with zero marginal cost electricity at midday. Conversely, demand-centered batteries experience minimal transmission constraints when discharging, but their ability to charge with low-cost electricity is constrained at midday.

Since the effects of individual battery additions cannot be identified, I classify batteries as either supply or demand-side to distinguish the impacts of storage capacity additions near

renewable generators from those in demand centers. To do so, I define a solar generating region in California using the average wholesale electricity prices at midday. First, I compute the average DAM LMP between 10 a.m. and 2 p.m. for each node in California. Since the northern half of the state experiences higher prices on average than the south, I bisect California at 35.5 degrees north and calculate separate midday price means for both regions[8]. The solar generating region is defined by the ZIP Codes that contain nodes with lower than average midday prices, shaded orange in Figure 6. Here, prices are depressed by the midday glut in solar generation. ZIP Codes with nodal prices above the average are less affected, shaded blue in Figure 6 to represent the high demand, low solar supply region.

I classify batteries in ZIP Codes with low average midday prices as supply-side and those in ZIP Codes with high average prices as demand-side. Battery locations are overlaid in green and scaled by nameplate capacity (MW) in Figure 6. The difference in average prices between the two regions is nontrivial, reaching up to 12 $/MWh as shown in Figure 7, emphasizing the magnitude and duration of the congestion-induced price spread between the renewable supply and demand regions in California.

[8]The distributions of nodes' average prices around the regional means is plotted for southern and northern California in appendix Figure v.

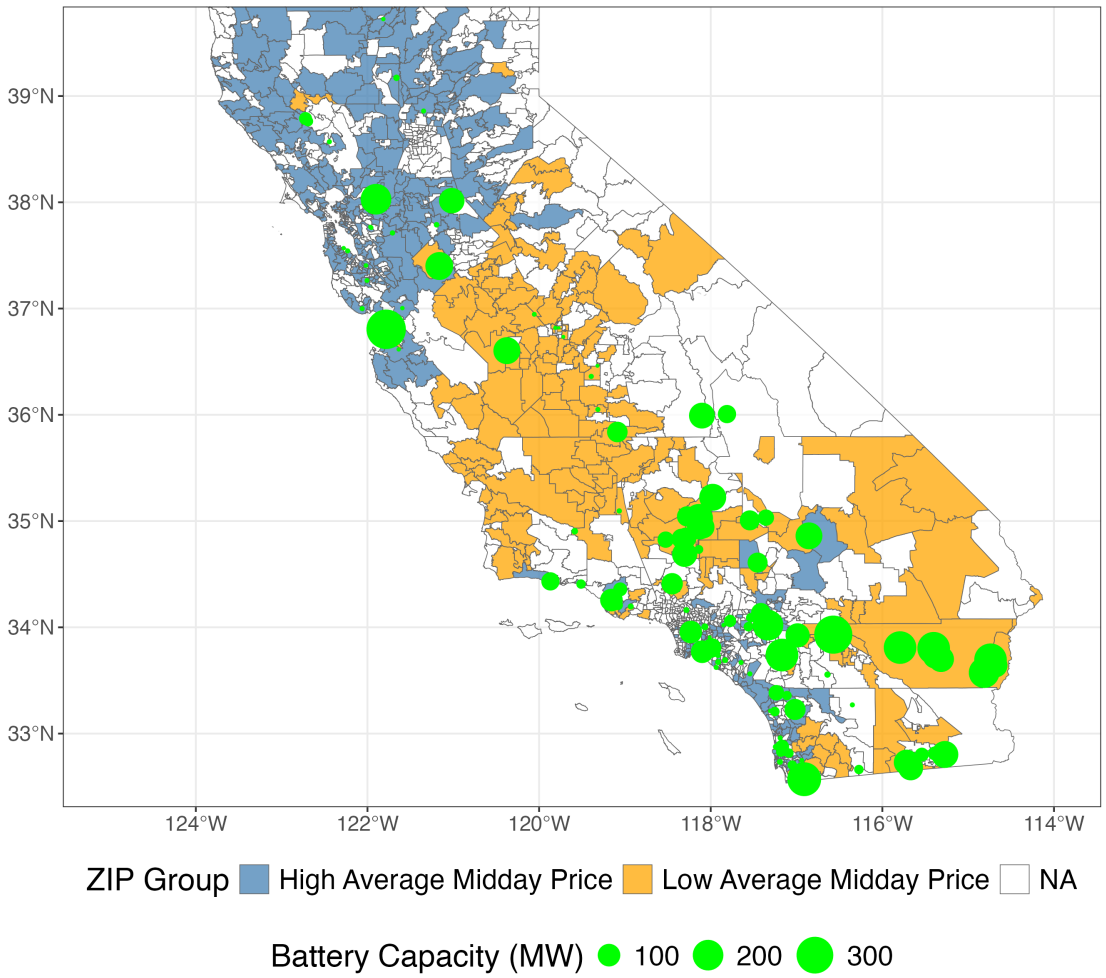


Figure 6: ZIP Codes where a majority of nodes with average midday prices below the regional mean are shaded orange and those above the mean are shaded blue. Batteries are shaded green and scaled by nameplate capacity (MW). Battery locations and nameplate capacities are from the EIA-860 Survey 2024. DAM LMPs are from the CAISO's OASIS from 2020-2024.

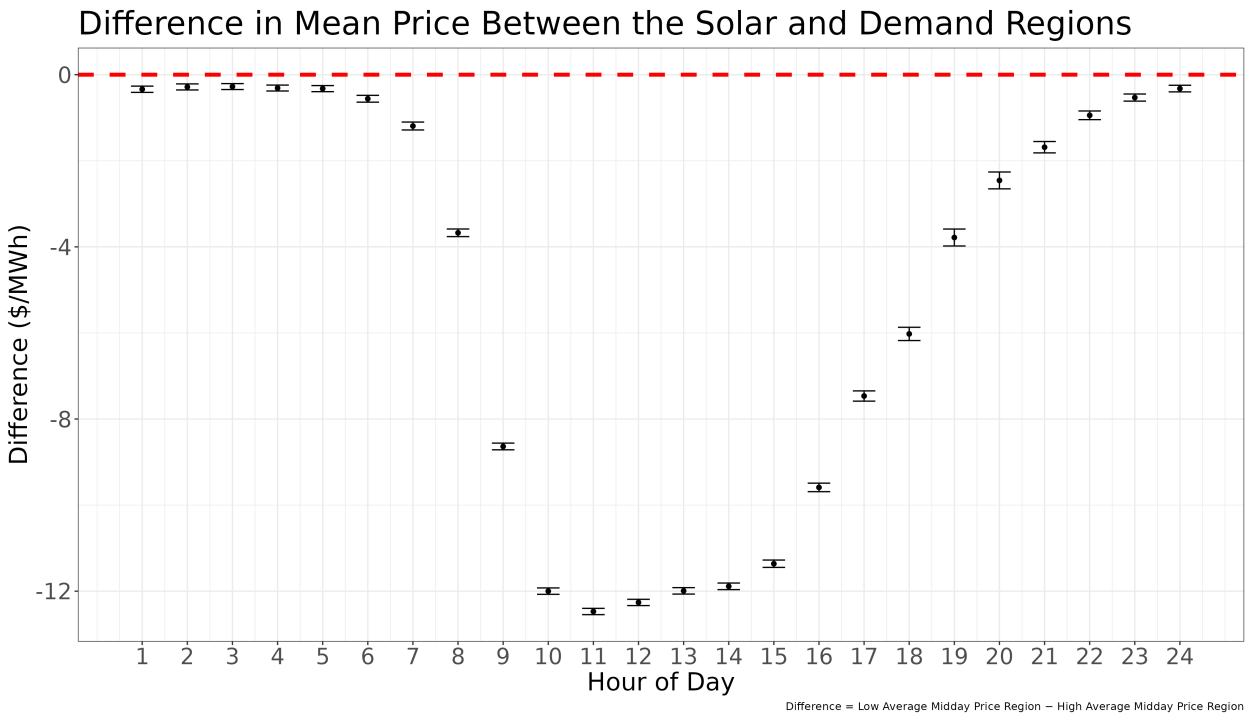


Figure 7: Hourly average average price difference between high and low average midday price regions with 95% confidence intervals. DAM LMPs from the CAISO's OASIS from 2020-2024.

The amount of storage capacity added in each region has varied over time. Figure 8 plots the cumulative battery capacity in ZIP Codes with low average midday prices in orange and in those with high average price ZIP Codes in blue. In the early half of the sample, battery capacity was added at similar rates in both regions. Then, towards the beginning of 2022, supply-side storage capacity grew rapidly while few batteries were added in demand centers. To determine if the effects of supply and demand-side batteries differed, an ideal analysis would estimate the impacts of each storage addition separately. Since I only observe state-aggregate battery output and capacity, I instead compare the effects of charging on curtailment before and after the divergence in co-located storage capacity.

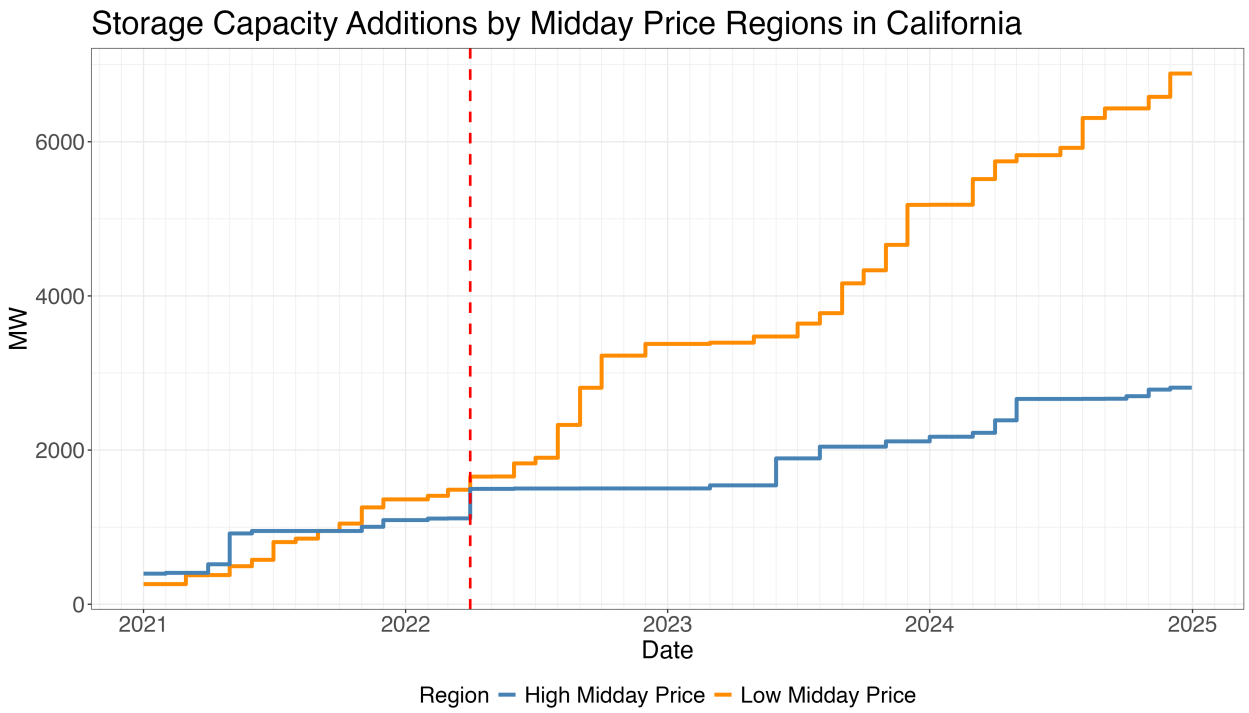


Figure 8: Cumulative battery capacity in ZIP Codes where a majority of nodes have low average midday prices in orange and in those with high average midday prices in blue. The first date when curtailment type was recorded in the CAISO's annual Production and Curtailment datasets is marked by the red dashed line and coincides with the growth in storage capacity in the low average midday price region. Batteries' nameplate capacity, location, and first month-year of operation are recorded in the EIA-860 Survey 2024.

2.3 Curtailment

Transmission line congestion not only affects the prices that solar generators receive, but also the quantity of electricity they produce. When output exceeds transmission lines' capacity, generators are curtailed to avoid damaging the grid. This occurs frequently in the early afternoon during California's sunny but temperate springs, when demand is low relative to solar generation.

Solar curtailment has increased in step with the state's solar generation capacity, which has almost doubled from 13.8GW in 2020 to 23.3 GW by the end of 2024[10]. The rising peak in monthly average total solar curtailment plotted in Figure 9 climbs to about 2800 MW in April of 2024, suggesting that up to 12.5% of the state's solar generation capacity

went unused. To estimate whether storage additions increased renewable generation, my empirical strategy accounts for the relationship between solar capacity and curtailment to avoid spuriously attributing the increase in curtailment to the change in battery capacity during the same period.

As of April 1st, 2022, the CAISO began recording curtailment by reason, either local or system. Local curtailment is caused by a glut of renewable output in a particular area in excess of the transmission capacity of nearby lines. This occurs far more frequently than system curtailment, which happens when the supply of electricity exceeds demand, requiring a system-wide reduction in generation. I define total curtailment after April 1st, 2022, as the sum of local and system curtailment.

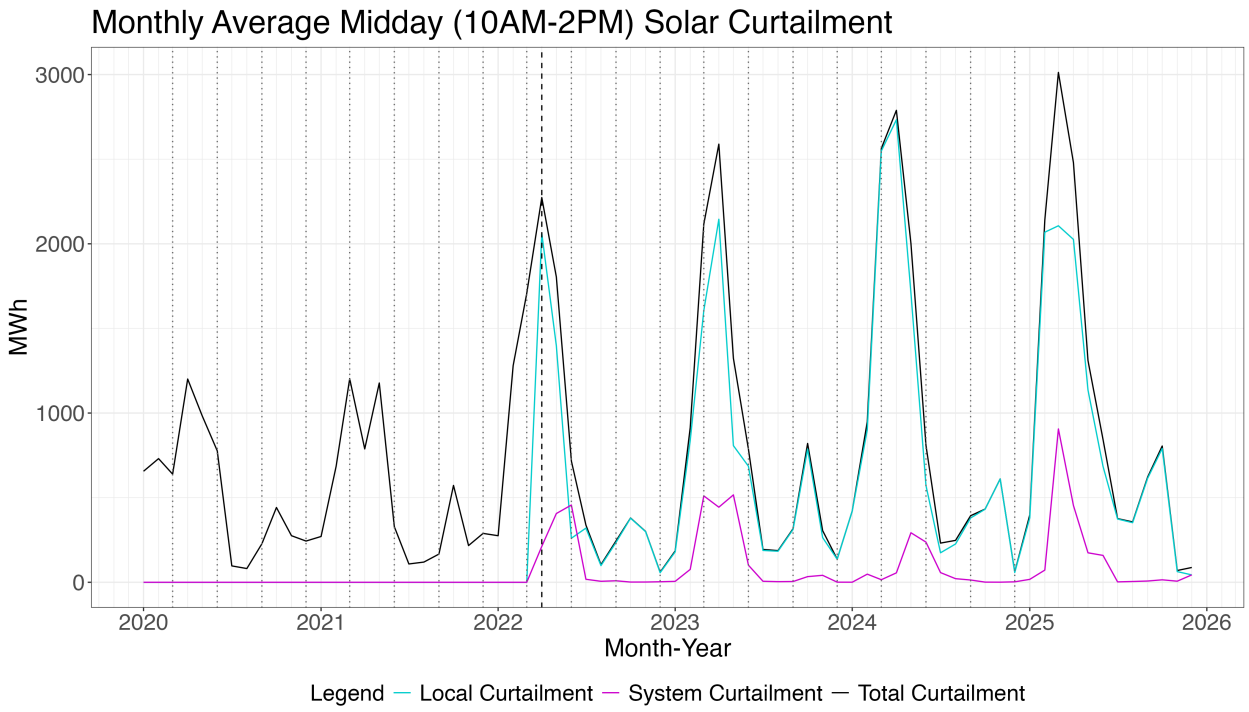


Figure 9: Monthly average solar curtailment by type. The vertical dashed line on April 1st, 2022 marks the first date that local and system curtailment were recorded. Data from the CAISO's annual Production and Curtailment datasets from 2020-2024.

The combination of lost output forced by binding transmission constraints and low prices

[10]https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy

during peak generating hours reduces the productivity of California's solar generators. Previous studies examined the effects of battery arbitrage, but disregarded how these impacts varied with batteries' location. Next, using a simplified analytical model of California's wholesale electricity market, I will describe when the impacts of supply and demand-side storage on curtailment differ. Then, I will estimate the impacts of charging on solar curtailment and compare the effects between the early half of the sample, when storage capacity was mixed between supply and demand-side sites, and the latter half, when it was predominantly co-located with solar generators.

3 Theoretical Model

I demonstrate when the impact of electricity arbitrage by batteries on renewable generation and the total cost of generating electricity depends on their location in a two-period, two-node model of an electrical grid. To represent the arrangement of California's solar generating region and its cities, the dispatch of renewable generation depends on transmission capacity to reach demand, which occurs exclusively at a separate node. Maximum renewable generation potential occurs in period one and peak load to period two, replicating the temporal imbalance between renewable supply and load experienced in markets with a high degree of solar penetration.

First, I establish the value of renewable generation in the absence of storage, which reduces the total cost of generating electricity by avoiding the use of high marginal cost thermal generators. Then, I show how these avoided costs increase when a battery is located either with demand or the renewable generator. When unconstrained by transmission capacity, arbitrage at either location smooths electricity demand and supply throughout the day, reducing total generation costs by increasing renewable generation. However, if transmission capacity limits the delivery of renewably generated electricity, a supply-side battery is uniquely able to prevent local curtailment, resulting in greater avoided costs. Despite its

inability to increase the utilization of the renewable generator when the grid is congested in period one, the demand-side battery provides greater cost savings when load is excessively high by offsetting peak thermal generation in period two. This theoretical result motivates my empirical specification by emphasizing the mechanisms driving observed changes in curtailment during the period of storage capacity growth in California.

I model a grid operator's choice to dispatch thermal generators under a simplified set of physical constraints imposed by the grid to illustrate the impacts of arbitrage on equilibrium generator dispatches and the total cost of generating electricity. Renewable generation and demand are assigned to separate nodes, $A \in \mathcal{N}$ and $B \in \mathcal{N}$ respectively, connected by a single transmission line with fixed capacity level, K. For simplicity, I assume that the market is closed to imports and exports. In the absence of storage, increasing the capacity of the renewable generator lowers the total cost of generating electricity until transmission constrains its output. A supply and demand-side battery are introduced separately to contrast the levels of dispatched renewable generation and additional avoided costs between the two cases. When the renewable generator is unconstrained by transmission, arbitrage by batteries at either location results in an equal amount of avoided costs by transferring renewable generation from the high supply, low demand first period to the high demand, low supply second period. The impact of temporal arbitrage differs between co-located and demand-centered batteries when transmission limits the flow of electricity from node A to B.

3.1 Model Formalization

I assume that the total generation cost function is quadratic, so that the lowest marginal cost generator is always dispatched first. The total cost of generating electricity is defined as,

$$TC(q_{j,t}) = \frac{1}{2} \sum_{j \in \mathcal{N}} \sum_{t=1}^{2} q_{j,t}^2$$

where $q_{j,t}$ is the non-negative level of dispatched thermal generation at node j in period t in MWh. Since my focus is on the impacts of electricity arbitrage, I assume that the thermal generators do not incur dynamic start-up costs and produce instantaneously within the periods in which they are dispatched to simplify away the ramping decisions that influence thermal output in reality. I also assume that the market is perfectly competitive, a realistic assumption in the California wholesale market given the CAISO's strict market power mitigation procedures.

The maximum potential renewable generation capacity at node A in period t in MWh, $\bar{R}_{A,t} = R_A^c c_t^f$, is the product of the fixed level of installed renewable capacity at node A, R_A^c, and the capacity factor, c_t^f, which creates temporal variation in renewable output. Since the within-day variation in potential renewable generation is determined almost entirely by solar in California, I represent midday and evening with period one and two, respectively, setting a higher capacity factor in the first period, $c_1^f > c_2^f$, and peak demand in the second, $D_{B,1} < D_{B,2}$, where demand is perfectly inelastic and measured in MWh. I assume that renewable generation at node B and demand at node A are zero in both periods. These assumptions can be easily modified to capture alternative settings in which the variation in renewable output is driven by evening wind generation.

The quantity of renewable generation dispatched at node A in period t, $R_{A,t}$, is influenced by three constraints. First, the renewable generator can never be dispatched at a level above its maximum potential capacity,

$$R_{A,t} \in [0, \bar{R}_{A,t}] \, \forall \, t$$

Second, the transmission line capacity, K, constrains the amount of energy that can be transmitted between the two nodes. Assuming no loss along the line, it must always be that,

$$R_{A,t} + q_{A,t} \leq K \, \forall \, t$$

Notice that without storage, only electricity produced at node A crosses the transmission line

since demand occurs exclusively at node B. Finally, to avoid blackouts and infrastructure damage, the frequency of the electrical current flowing across the transmission line must always be maintained by balancing the total quantity of electricity supplied and demanded,

$$R_{A,t} + \sum_{j \in \mathcal{N}} q_{j,t} = D_{B,t} \, \forall \, t$$

A cost-minimizing grid operator will dispatch the renewable generator, which produces at zero marginal cost, until one of these constraints binds. If transmission capacity or demand is insufficient to allow for the maximum amount of potential renewable generation to be dispatched, some amount will be curtailed either locally or system-wide, respectively. Local curtailment occurs when the maximum potential renewable generation exceeds transmission capacity, $K < \bar{R}_{A,t} \leq D_{B,t}$, causing congestion which restricts the flow of electricity between nodes. The excess renewable generation capacity is curtailed locally. When the line is uncongested but demand is insufficient to allow the grid operator to utilize the full maximum potential of the renewable generator and satisfy the balance constraint, $D_{B,t} < \bar{R}_{A,t} \leq K$, system curtailment is required.

In cases including either a battery co-located with the renewable generator at node A or with demand at node B, I assume that the battery starts period one without charge and consumes electricity generated by either the renewable or thermal generators to charge fully. Then, in period two, it discharges its full capacity. The energy in MWh consumed by the battery is negative in period one, $C_{A,1} \leq 0$, adding to demand, and positive in period two, $C_{A,2} \geq 0$, an alternative source of zero marginal cost electricity. I assume that the battery does not lose energy and can never charge or discharge a quantity greater than its fixed storage capacity, $\bar{C}_j$,

$$|C_{j,t}| \leq \bar{C}_j \, \forall \, t \tag{1}$$

3.1.1 Case 1: No Storage

Consider the grid operator's problem of minimizing the total cost of generating electricity by dispatching thermal generators at each node in both periods, given exogenous demand and renewable generation potential.

$$\begin{aligned} &\min_{\mathbf{q}} \; TC(q_{j,t}) \\ s.t. \quad &R_{A,t} + \sum_{j \in \mathcal{N}} q_{j,t} = D_{B,t} \; \forall \, t \\ &R_{A,t} + q_{A,t} \leq K \; \forall \, t \\ &R_{A,t} \leq \bar{R}_{A,t} \; \forall \, t \\ &q_{j,t}, R_{A,t} \geq 0 \; \forall \, j \in \mathcal{N}, t \end{aligned} \tag{2}$$

When unconstrained by transmission, the renewable generator is dispatched either at its maximum potential capacity or until demand is met. Any remaining net demand is split between the two thermal generators at nodes A and B. If the maximum potential renewable generation capacity exceeds load, the grid operator curtails the excess output system-wide. More commonly, transmission capacity constrains renewable output when a local generation surplus congests the grid. In this case, the renewable generator is dispatched until the transmission constraint binds. Net demand must then be met entirely by the thermal generator at node B.

Renewable generation is limited by either transmission capacity or demand during the peak production period, reducing its value. Since transmission capacity is fixed in the short run and residential electricity demand is inflexible, battery storage offers an alternative mechanism for increasing the productivity of the renewable generator, potentially serving as a substitute for transmission capacity by smoothing both the supply of renewably generated electricity and demand across the day.

When transmission constrained, a battery's ability to prevent curtailment depends on its

location. A battery co-located with the renewable generator will always be able to charge with clean, zero marginal cost electricity regardless of transmission capacity. By storing energy when maximum potential renewable generation exceeds the line capacity and selling it later, the battery transfers clean electricity generated at midday to the evening. However, discharging a supply-side battery may crowd out renewable production if the generation potential remains high later in the day. Evening congestion also limits a supply-side battery's ability to offset peak thermal generation at the demand center. Since the marginal cost of generating electricity increases with the quantity of dispatched thermal generation, a demand-side battery can greatly reduce total generation costs if peak load occurs during the discharge period; however, a demand-centered battery is unable to prevent local curtailment and is therefore less complementary to the renewable generator.

The following cases show that the potential for a battery to reduce generation costs by preventing curtailment and/or offsetting thermal generation depends on its location when the transmission constraint binds.

3.1.2 Case 2: Supply-Side Storage at Node A

If a battery is co-located with the renewable generator at node A, the grid operator's problem becomes,

$$\begin{aligned} &\min_{\mathbf{q}} \; TC(q_{j,t}) \\ s.t. \quad &R_{A,t} + C_{A,t} + \sum_{j \in \mathcal{N}} q_{j,t} = D_{B,t} \; \forall \, t \\ &R_{A,t} + C_{A,t} + q_{A,t} \leq K \; \forall \, t \\ &R_{A,t} \leq \bar{R}_{A,t} \; \forall \, t \\ &|C_{A,t}| \leq \bar{C}_A \; \forall \, t \\ &q_{j,t}, R_{A,t} \geq 0 \; \forall \, j \in \mathcal{N}, t \end{aligned} \tag{3}$$

The impacts of supply and demand-side batteries are equivalent when the transmission constraint is nonbinding. Charging increases demand in period one, potentially reducing

system curtailment if renewable generation potential exceeds load. Electricity produced at zero marginal cost is transferred to the second period to offset thermal generation, lowering generation costs and increasing the value of renewables. However, if renewable generation potential is insufficient to meet demand and fully charge the battery, thermal generation at both nodes will increase, raising generation costs in period one. Total generation cost may still fall if battery discharge offsets peak levels of thermal generation in period two.

A supply-side battery is uniquely able to prevent local curtailment when renewable output congests the transmission line in period one. The battery at node A is unconstrained by transmission capacity when charging, allowing it to charge fully with zero marginal cost electricity that would have otherwise been curtailed. In period two, the battery provides an alternative source of electricity that is sent across the line to node B. Supply-side storage offers the greatest cost savings when renewable generation falls low enough in period two to allow the battery to discharge its full capacity, maximizing its ability to shift electricity produced by renewables at midday to offset thermal generation in the evening.

Storage and renewables are less complementary when renewable production occurs during the discharge period, in which case, discharge from a co-located battery may increase congestion. In California, batteries began discharging around 5 p.m. on average in 2024 while solar generators were still producing, depicted in Figure 4. An increase in electricity supply from co-located batteries not only increases the likelihood of transmission congestion and curtailment, as described in the period two transmission constraint, but also lowers prices for other generators. For batteries and solar generators to be complements, any lost profits later in the day must be offset by a boost in midday prices and reductions in curtailment. Batteries share a similar relationship with wind generators, which benefit from the increase in overnight demand but compete with batteries in the evening.

3.1.3 Case 3: Demand-Side Storage at Node B

Finally, when storage is located at node B, the grid operator's problem becomes,

$$\begin{aligned} &\min_{\mathbf{q}} \; TC(q_{j,t}) \\ s.t. \quad &R_{A,t} + C_{B,t} + \sum_{j \in \mathcal{N}} q_{j,t} = D_{B,t} \; \forall \, t \\ &R_{A,t} + q_{A,t} \leq K \; \forall \, t \\ &R_{A,t} \leq \bar{R}_{A,t} \; \forall \, t \\ &|C_{B,t}| \leq \bar{C}_B \; \forall \, t \\ &q_{j,t}, R_{A,t} \geq 0 \; \forall \; j \in \mathcal{N}, t \end{aligned} \tag{4}$$

Congestion in the charging period prevents a demand-side battery from reducing local curtailment, making it less complementary with the renewable generator and potentially increasing thermal generation in period one. Despite its limited ability to affect renewable output when charging, discharge from a demand-side battery is unconstrained by transmission capacity, saving the grid operator the exorbitant cost of dispatching the thermal generator at node B at peak levels when load is high and the line is congested in period two.

3.2 Model Parameterization and Simulation

I simulate how the value of renewables, expressed in terms of the costs avoided from offsetting thermal generation, is affected by supply and demand-side storage as installed renewable capacity increases while transmission capacity remains fixed. I contrast the total cost of generating electricity between two day types, one with high and the other with low evening demand, to show that the value of electricity arbitrage enabled by storage is influenced both by the timing of transmission line congestion and the diurnal pattern of net load. When midday congestion caused by excess renewable generation occurs frequently, supply-side batteries' ability to mitigate local curtailment results in greater avoided costs by transferring

additional zero marginal cost electricity to the high-demand period. However, if there is a stark imbalance between renewable supply and load, demand-centered batteries create the largest cost savings by offsetting peak levels of thermal generation despite their inability to prevent local curtailment.

I assign values to the transmission line capacity, renewable capacity factors, and load. Demand in the first period is 600 MWh, 100 MWh greater than the fixed line capacity, creating local curtailment at higher levels of installed renewable capacity. I create two representative high and low demand days by setting period two demand at 1000 and 1500 MWh, respectively. In California, evening peak load is highest in the summer and early fall when residents run their ACs to avoid the heat, often requiring the dispatch of expensive peaker thermal plants. During the temperate winter and spring, evening demand is lower while midday solar output remains high. To model the variation in solar generation throughout the day in California, renewables generate only at midday, with a renewable capacity factor of one in period one and zero in period two. In cases that include a battery, its capacity is fixed at 250 MWh. To compare the total cost of generating electricity between the two siting types as output from renewables increases, I iterate over values of installed renewable capacity from zero to 2000 MWh.

Parameter	Value	Description
$D_{B,1}$	600	Demand at node B in period 1 in MWh
$D_{B,2}^{\text{high}}$	1500	Demand at node B in period 2 on the high demand day in MWh
$D_{B,2}^{\text{low}}$	1000	Demand at node B in period 2 on the low demand day in MWh
K	500	Transmission line capacity in in MW
c_1^f	1	Renewable capacity factor in period 1
c_2^f	0	Renewable capacity factor in period 2
$\overline{C}$	250	Battery capacity in MW
R_A^c values	0 – 2000 (step 10)	Installed renewable generation capacity in MW

Table 1: Model parameters.

Without storage, the total cost of generating electricity, displayed in Figure 10, falls as the level of installed renewable generation capacity increases, offsetting thermal generation until the transmission constraint binds, at which point additional renewable capacity only increases curtailment, as shown in Figure 12. The avoided costs, plotted in Figure 11, are the difference between total generation costs with renewables and a baseline cost without renewables. Once transmission constrains the dispatch of renewables, installing more generation capacity does not result in additional avoided costs.

Total and avoided costs are plotted in green and blue for the cases with a supply or demand-side battery, respectively. Without renewables, batteries at either node increase demand by 250 MWh in period one when they charge, which is split equally between the two thermal generators at nodes A and B. On low-demand days, discharge from the battery at node B supplies 250 MW of power directly to where it is demanded, allowing net load to be shared evenly between the two thermal generators. Conversely, when the battery at A discharges, it crowds out thermal generation at its own node, both of which are constrained by

the transmission line capacity. So while the supply-side battery can offset the same amount of thermal generation, costs are greater since the dispatch of the generator at node B remains high. Consequently, supply-side storage provides no cost savings without renewables as it only shifts thermal production at node A between periods, increasing demand by 250 MWh in period one and offsetting an equal amount in period two.

When renewable generation capacity is low, arbitrage by demand-side storage creates greater cost savings on both day types because it is never constrained by transmission when discharging, offsetting the maximum amount of thermal generation in period two. When demand cannot be divided equally between the two thermal generators in the evening, the grid operator relies on the generator at node B to meet peak load, drastically increasing the quadratic total cost function. Located on the demand side of the transmission constraint, discharge from a battery at node B reduces thermal generation there from 1000 MWh to 750 MWh. Therefore, the relative cost savings of demand-side storage persist, even at higher levels of installed renewable generation capacity, on days with high evening load.

The additional avoided costs created by supply-side storage grow with the level of installed renewable generation capacity. When unconstrained by transmission, storage at either node results in an equal amount of avoided costs, as both batteries are able to arbitrage using renewably generated electricity. Once the dispatch of renewables becomes transmission-constrained, the supply-side battery is uniquely able to prevent local curtailment, increasing the utilization of the renewable generator by an amount equal to the fixed battery capacity. Consequently, curtailment is always lower when storage is co-located with the renewable generator, reducing total costs on days with low evening peak demand more so than demand-side storage.

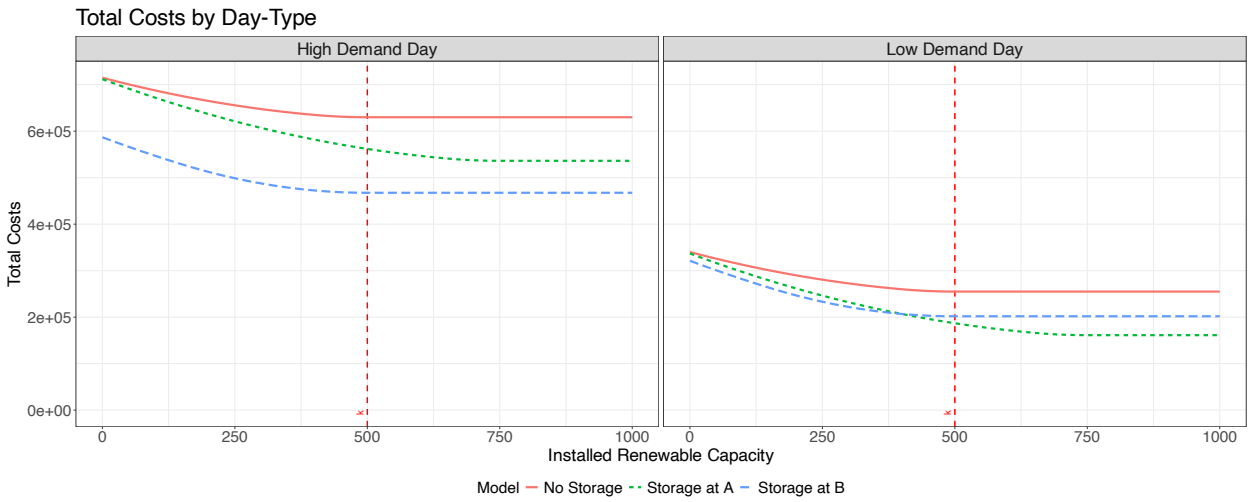


Figure 10: Total costs.

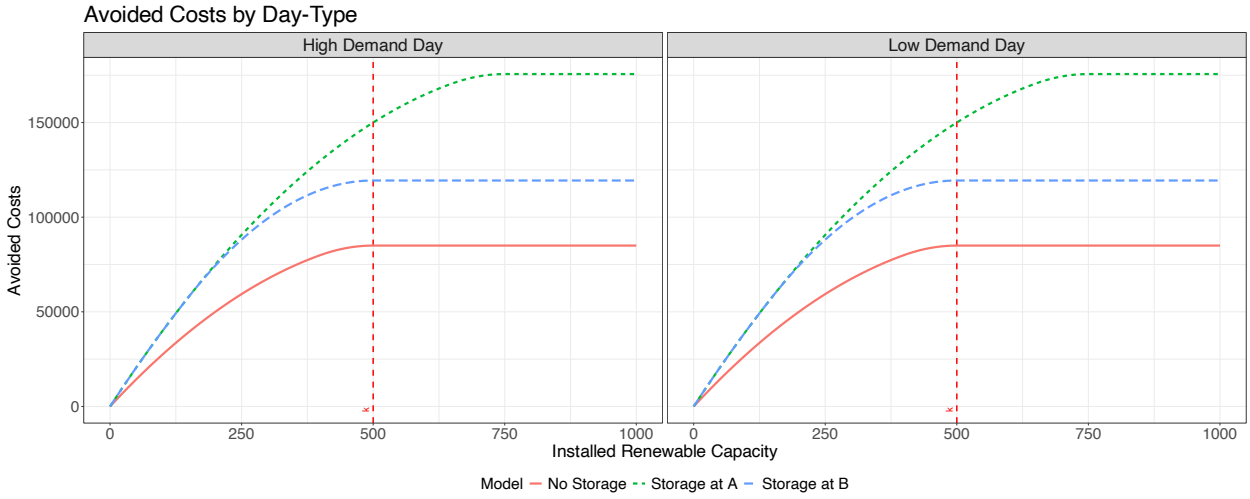


Figure 11: Avoided costs.

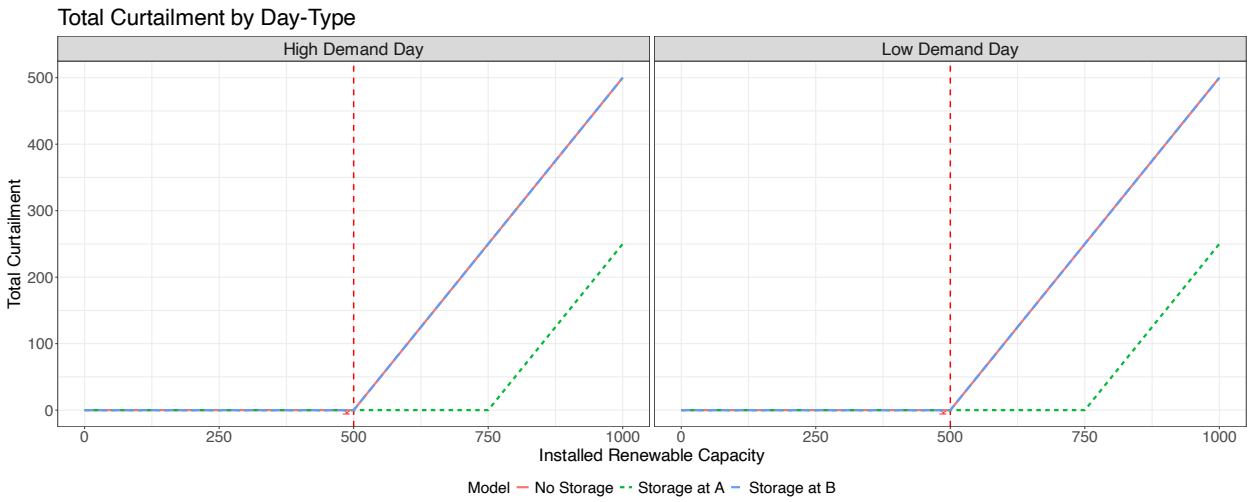


Figure 12: Total curtailment.

The intuition described in this theoretical model motivates my empirical method by illustrating the propensity of each storage type to affect curtailment. The model demonstrates that supply-side storage reduces local curtailment regardless of transmission line capacity due to its proximity to the renewable generator, while demand-side batteries face are exposed to congestion when charging. Batteries of either type are equally well suited to prevent system curtailment, which is remedied by an increase in demand anywhere in the grid. Given the prevalence of local curtailment in the CAISO market, supply-side batteries likely increase renewables' productivity more so than demand-side batteries.

4 Empirical Method

4.1 Research Design

I ask whether the increase in midday electricity consumption by batteries affected the productivity of solar generators in California during the growth in storage capacity from 2021 through 2024. To investigate if charging increased solar generation by reducing curtailment, I estimate the following general model:

$$\text{CURTAILMENT}_{f,h,d} = \alpha_{h,m,y} + \beta_h \text{BATTERY_SUPPLY}_{f,h,d} + \Theta_{h,s,y}\mathbb{X} + \epsilon_{f,h,d}$$

where $\text{CURTAILMENT}_{f,h,d}$ is the level of solar curtailment in MWh and $\text{BATTERY_SUPPLY}_{f,h,d}$ is the aggregate quantity of power consumed by batteries in MWh when they charged during five-minute interval f in hour h on day d in the CAISO market. I estimate the model separately for each hour during the peak in daily solar output and charging, from 10 a.m. to 2 p.m., as shown in Figure 4, allowing for heterogeneous effects of charging on curtailment across the midday hours.

The CAISO records the aggregate level of power supplied by batteries, which is a negative quantity when they charge. Therefore, if charging reduced solar curtailment on average in hour h, the sign of the coefficient β_h will be positive. A coefficient value of one indicates that, on average, in hour h, the marginal MWh of energy consumed by batteries when they charged was supplied entirely by solar generation that would have been curtailed. Since other generation sources were online when batteries charged and likely responded to the change in electricity demand, a reasonable β_h coefficient should be within the range $[0, 1)$.

During the adoption of batteries, solar generation capacity increased expeditiously as well, shown in Appendix Figure i, directly affecting the frequency and magnitude of solar curtailments. To avoid spuriously attributing the rise in solar curtailment to increased battery activity, I create exogenous measures of renewable generation potential by adding the observed level of aggregate dispatched renewable generation and curtailment in the CAISO market for both solar and wind. Trends in electricity demand are controlled for using the observed level of aggregate load in the CAISO market. In addition to the contemporaneous measures of these covariates, the matrix $\mathbb{X}$ also contains the total daily amount, accounting for differences in observed curtailment across days with varying levels of demand and renewable supply. The coefficients for the controls vary by season-year, allowing for heterogeneity

in the effects of electricity demand and renewable supply on curtailment in each season of the sample. Other unobservable long-run and seasonal trends in generation or demand likely affected both battery output and curtailment, motivating the inclusion of month-by-year fixed effects.

Even within individual months of the sample, other latent short-run supply shocks may have influenced prices and congestion, affecting charging behavior and curtailment. For instance, a surge in thermal units online near solar generators would increase the likelihood of transmission congestion and depresses prices, increasing curtailment and providing battery operators with an incentive to charge. The simultaneous determination of battery supply and curtailment necessitates an alternative strategy to identify the coefficient β_h.

Since the variation in battery supply is nonrandom, a function of unobserved factors that are correlated with curtailment, I use the state-aggregate cumulative battery capacity as an instrument for charge in a two-stage least squares estimation framework. The growth in cumulative storage capacity is also strongly correlated with battery output, shown in Figure 1, which illustrates storage additions as discrete events, using batteries' first month of operation recorded in the EIA-860 survey and assuming that batteries were fully utilized on the first day of the month. This likely attributes too much storage capacity to the earlier half of the first operating months. An ideal instrument would measure the actual rate of battery capacity operating in California, providing a daily measure of storage additions as they connected to the grid. Since I only observe the total storage capacity added in each month, I instead take the total capacity added in each month and divide it by the number of days to construct a linear trend in cumulative storage capacity, plotted in Appendix Figure vii. This is a more realistic assumption for larger batteries, which are composed of multiple cells that switch on gradually over time. If the assumption of linear growth is incorrect, any discrepancy from the actual rate of storage additions only weakens the instrument since battery capacity is always greater at the end of the first operating months compared to the beginning. Within months, changes in storage capacity are exogenous with respect to

curtailment due to the long-term infrastructure planning that determines batteries' size and location.

In the first stage, I estimate:

$$\begin{aligned}\text{BATTERY_SUPPLY}_{f,h,d} = {} & \pi_{1,h}\widetilde{\text{CAPACITY}}_d \\ & + \pi_{2,h}\widetilde{\text{CAPACITY}}_d \times \text{SOLAR}_d \\ & + \pi_{3,h}\widetilde{\text{CAPACITY}}_d \times \text{LOAD}_d \\ & + \pi_{4,h}\widetilde{\text{CAPACITY}}_d \times \text{WIND}_d \\ & + \pi_{5,h}\widetilde{\text{CAPACITY}}_d \times \text{WIND}_{f,h,d} \\ & + \delta_{h,m,y} + \Phi_{h,s,y}\mathbb{X} + \nu_{f,h,d}\end{aligned} \tag{5}$$

where $\widetilde{\text{CAPACITY}}_d$ is the linear trend in cumulative battery capacity in California, which varies daily within the months when batteries began operating. The instrument is interacted with the total daily level of solar and wind generation potential, total daily load, and the contemporaneous level of wind generation potential, allowing the effect of increased storage capacity on changing to differ across days with varying renewable generation potential and electricity demand. The interaction with the five-minute level of aggregate wind generation potential increases the variation of the instrument within days, explaining patterns in charging behavior across hours driven by changes in renewable generation. The same set of covariates and month-year fixed effects are included to control for long-run and seasonal patterns in generation and demand.

The fitted level of battery output in five-minute interval f in hour h on day d is then included in the second stage:

$$\text{CURTAILMENT}_{f,h,d} = \alpha_{h,m,y} + \beta_h\widehat{\text{BATTERY_SUPPLY}}_{f,h,d} + \Theta_{h,s,y}\mathbb{X} + \epsilon_{f,h,d} \tag{6}$$

4.2 Results

Using the full sample period from 2021 through 2024, I find a statistically significant effect of charging on total solar curtailment at the 5% level from 10 a.m. to 12 p.m. as shown in Figure 13, with the marginal MWh of power consumed by batteries reducing total solar curtailment by 0.5 MWh at noon. Coefficient estimates further from one indicate that while batteries were absorbing power produced by solar generators, half of the electricity used to charge California's battery fleet came from other sources. Previous work has found that the most flexible generators, which are natural gas turbines in California, are more reactive to changes in demand.

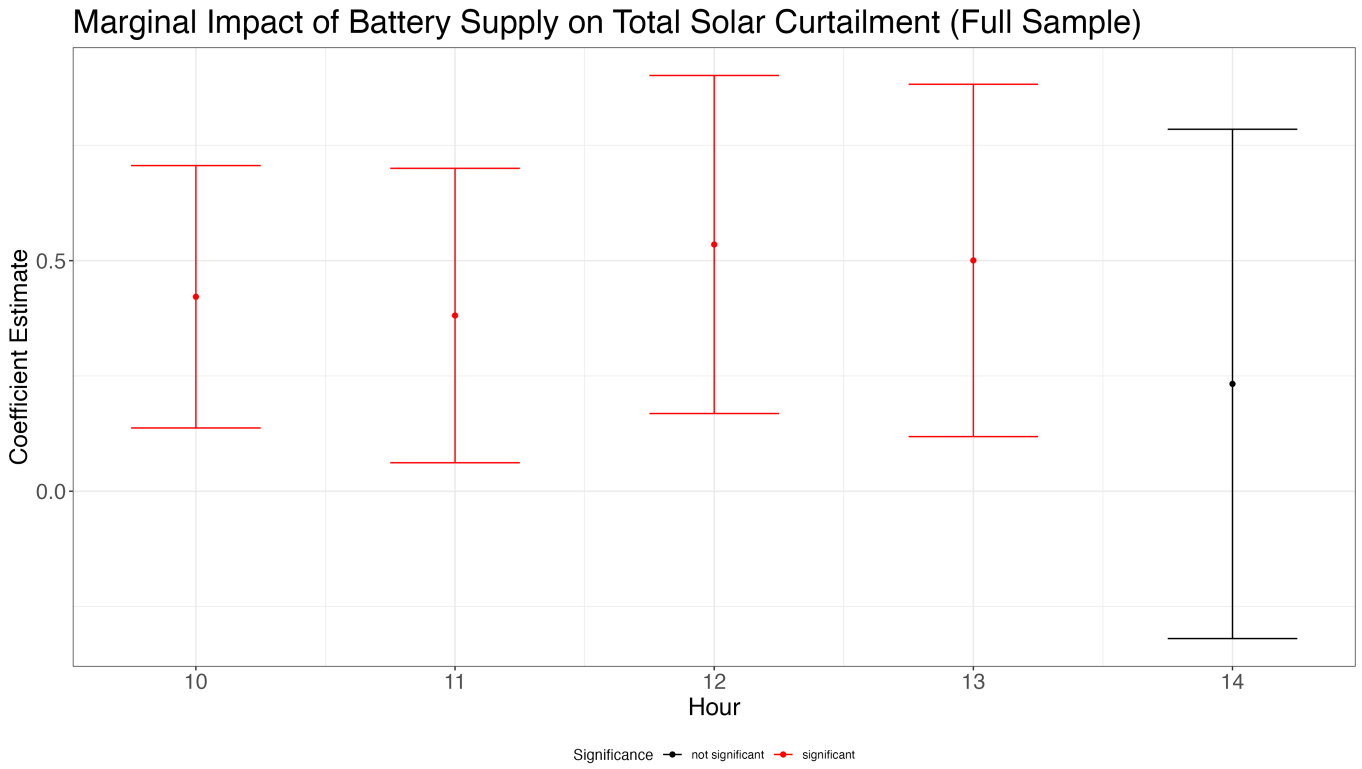


Figure 13: Second stage estimates of the coefficient β_h from 10 a.m. to 2 p.m. with 95% confidence intervals. White standard errors use 36 periods of lags. Coefficient estimates significant at the 5% level are colored red.

The two-stage least squares estimator identifies the weighted average local treatment effect during months in which increased cumulative storage capacity influenced battery out-

put. Greater weights are applied to months with the largest change in storage capacity and the highest level of solar curtailment, potentially attenuating the results given the limited number of capacity additions during high curtailment periods. Thus, the estimates shown in Figure 13 should be considered as a lower bound for the true effect of charging on solar curtailment.

4.2.1 Supply vs. Demand-Side Storage

The theoretical model indicated that supply-side batteries have a greater impact on congestion-induced local curtailment. Since I only observe aggregate battery supply, I cannot directly identify the effect of charging in each region separately. Instead, I exploit the variation in storage capacity added in California's low and high-price regions before and after April 2022 and the type of curtailment affected after, either system or local. Prior to April 2022, the largest capacity additions occurred in regions with high average midday prices, as shown in Figure 8. These storage additions installed closer to demand centers drove changes in battery output more so than the few smaller batteries co-located with renewables during the same period. Similarly, during the latter half of the sample, almost all of the new storage capacity was co-located with solar arrays, affecting charge and discharge patterns more so than the few demand-side additions. I compare the results estimated using pre- and post-April 2022 sub-samples to determine which siting type was most effective at reducing total solar curtailment. After April 2022, the CAISO records curtailment by type, system, or local, plotted in Figure 9. For batteries to reduce local solar curtailment, which is caused by localized gluts in output, they need to be located on the supply-side of the transmission constraint, whereas batteries anywhere in the grid can affect system curtailment.

Table 2: Second Stage Coefficients on Battery Supply (Hourly)

	Full Sample	Pre-April 2022	Post-April 2022		
	(Total Curtailment)	(Total Curtailment)	(Total Curtailment)	(Local Curtailment)	(System Curtailment)
Hour 10	0.422***	-0.165	0.497***	0.446***	0.051
	(0.145)	(1.233)	(0.126)	(0.123)	(0.033)
Hour 11	0.381**	-1.358	0.491***	0.414***	0.077
	(0.163)	(1.552)	(0.145)	(0.147)	(0.060)
Hour 12	0.535***	0.418	0.682***	0.567***	0.115*
	(0.187)	(0.933)	(0.183)	(0.178)	(0.067)
Hour 13	0.500**	1.214	0.694***	0.508***	0.185**
	(0.195)	(1.072)	(0.213)	(0.197)	(0.091)
Hour 14	0.233	-0.065	0.321	0.253	0.069
	(0.282)	(1.921)	(0.317)	(0.308)	(0.068)

Notes: Newey–West standard errors with 36 lags in parentheses. * p<0.10, ** p<0.05, *** p<0.01.

Comparing the second and third columns of Table 2, null effects before April 2022, when storage was mixed between siting types, and large significant reductions in total solar curtailment after, is consistent with the theorized advantage of supply-side storage in increasing the utilization of solar generators. My theoretical intuition is further supported by the smaller effect on system curtailment, which is equally affected by supply and demand-side storage, and large reductions in local curtailment after April 2022, shown columns Three and Four of Table 2, respectively.

After April 2022, more than half of the marginal MWh of energy used to charge the state's battery fleet between noon and 1 p.m. was supplied by solar generation that would have been curtailed. Since there were minimal changes in storage capacity during months with the highest levels of curtailment in the latter half of the sample, the post-April 2022 results are a lower bound on the true local average treatment effect of charging on solar curtailment.

5 Discussion

This paper finds that batteries and renewable generators are complements when charging and generation occur simultaneously and when charging is unconstrained by transmission capacity. The intuition laid out in the theoretical model and supported by empirical evidence demonstrates that co-located batteries are better complements to renewable generators than demand-side storage due to their unique ability to reduce curtailment when the grid is congested. Despite this advantage, batteries located in demand centers offer greater cost savings during peak load events, which necessitates the dispatch of expensive and emissions-intensive urban thermal generators. Current federal and California state policies designed to incentivize storage investments do not explicitly account for these benefits, potentially resulting in a socially inefficient allocation of storage capacity across the state.

California has set a hard deadline to decarbonize its electricity supply and is rapidly investing in renewable generation capacity to do so. The 57.5 GW[11] of additional solar generation capacity needed to meet the state's goal must be supplemented with transmission investments, which require coordination across a diverse set of stakeholders, a process that has proven ineffective in supplying adequate transmission capacity in a timely manner. While grid development lags behind renewable investments, much of the state's new generation capacity will go underutilized, as localized surpluses continue to be curtailed. In the meantime, supply-side batteries offer a short-term solution to inadequate transmission capacity, increasing the productivity of renewable investments. In the long run, as generation capacity increases, fewer transmission and renewable generation investments will be required to achieve a carbon-free electricity market if a larger share of the state's battery fleet is located on the supply side of the transmission constraint.

Ensuring reliability in a grid powered primarily by variable renewable energy will also require policy to address the renewable supply and load imbalance, which perpetuates the use of thermal generators. Alternative flexible generation sources and demand shifting will

[11] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K367/525367911.pdf

be necessary to replace natural gas plants in the state's urban centers, which are often called upon to meet peak net load in the evenings. Always able to shift load between charging and discharging periods, demand-side batteries create greater total cost savings in the short run during peak load events by offsetting the dirtiest and most expensive natural gas generators. However, due to their exposure to congestion when charging, demand-side batteries are unable to prevent local curtailment. Therefore, a storage fleet sited primarily with demand will necessitate greater investment in transmission capacity compared to a supply-side fleet in the long run to connect California's renewable generators with demand.

Investment incentives must strike a balance between ensuring grid reliability, required to wean off fossil fuel generation, and increasing the utilization of the state's renewable generators. Policymakers must weigh the external benefits of emissions reductions and avoided infrastructure costs when providing incentives for new storage projects. While demand-side storage creates short-run external social benefits by offsetting emissions-intensive urban peaker plants, supply-side storage requires fewer investments in renewable generation and transmission capacity in the long run to achieve the RPS.

I find that while co-located batteries are preventing solar curtailment, only 50% of the electricity used to supply the marginal MWh of battery charge was generated by solar, begging the question of where the other half is coming from. Instead of offsetting emissions, it may be that storage is shifting thermal generation to earlier in the day, providing generators that would have otherwise shut down at midday with a reason to stay on. Charging likely causes a geographic redistribution of emissions as well, potentially increasing imports from neighboring states that produce electricity primarily with fossil fuels. As the Western Energy Imbalance Market becomes more interconnected through the extended day-ahead market and battery capacity grows in other states, more power from batteries will be imported into California. Currently, the state's Cap-and-Trade Program uses a single emissions factor for batteries charged using either a single source or unspecified grid power. While the California Air Resources Board claims this emissions factor is conservative, it likely does not reflect

the true carbon intensity of electricity stored in markets with lower renewable penetration, especially for hybrid batteries that, while proximate to renewable generators, absorb power from other sources. Further work is required to measure the carbon content of electricity stored by batteries to determine which fuel sources respond to the increase in electricity demand during charging periods.

Successfully transitioning away from fossil fuels to variable renewable energy will require investments in complementary storage technologies. This paper shows that the complementarity between storage and renewables depends not only on the correlation between renewable supply and demand but also on their relative locations in the grid due to the market fragmenting effect of transmission congestion. Policy must consider which locations for new storage projects achieve an optimal allocation of resources throughout the grid to ensure reliability and the maximal utilization of renewable generation capacity.

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Appendix

Background and Data

Generation and Load

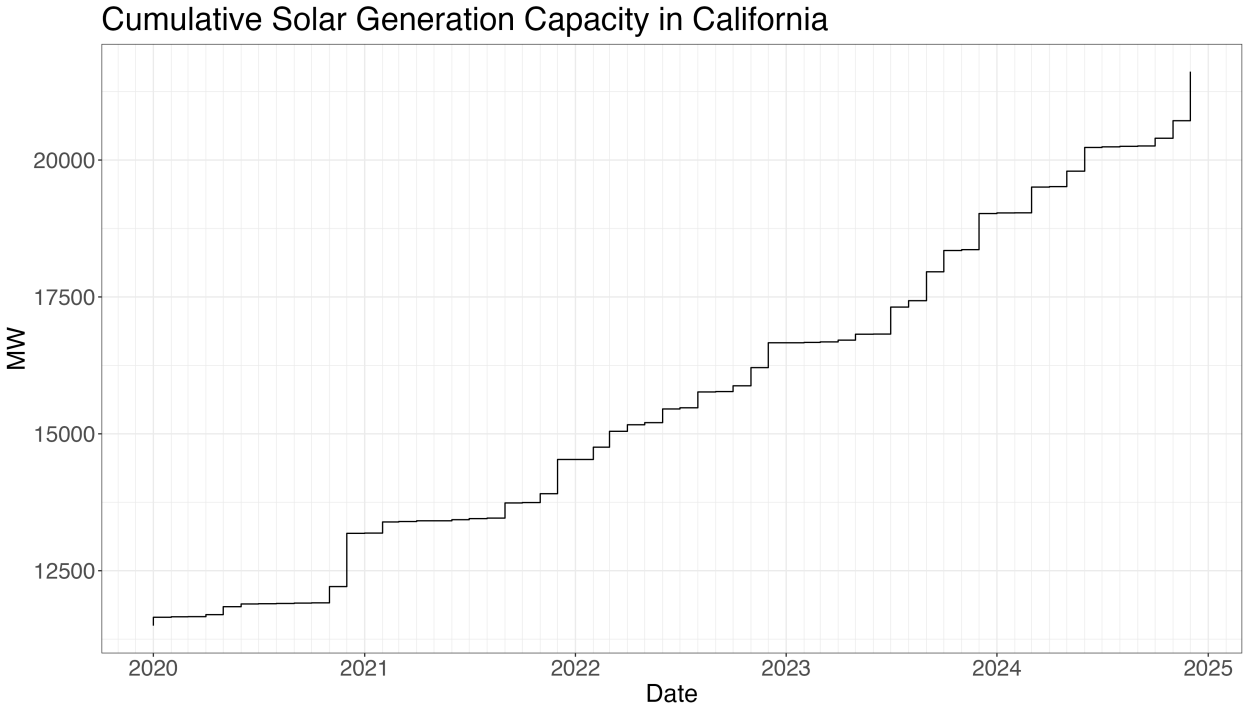


Figure i

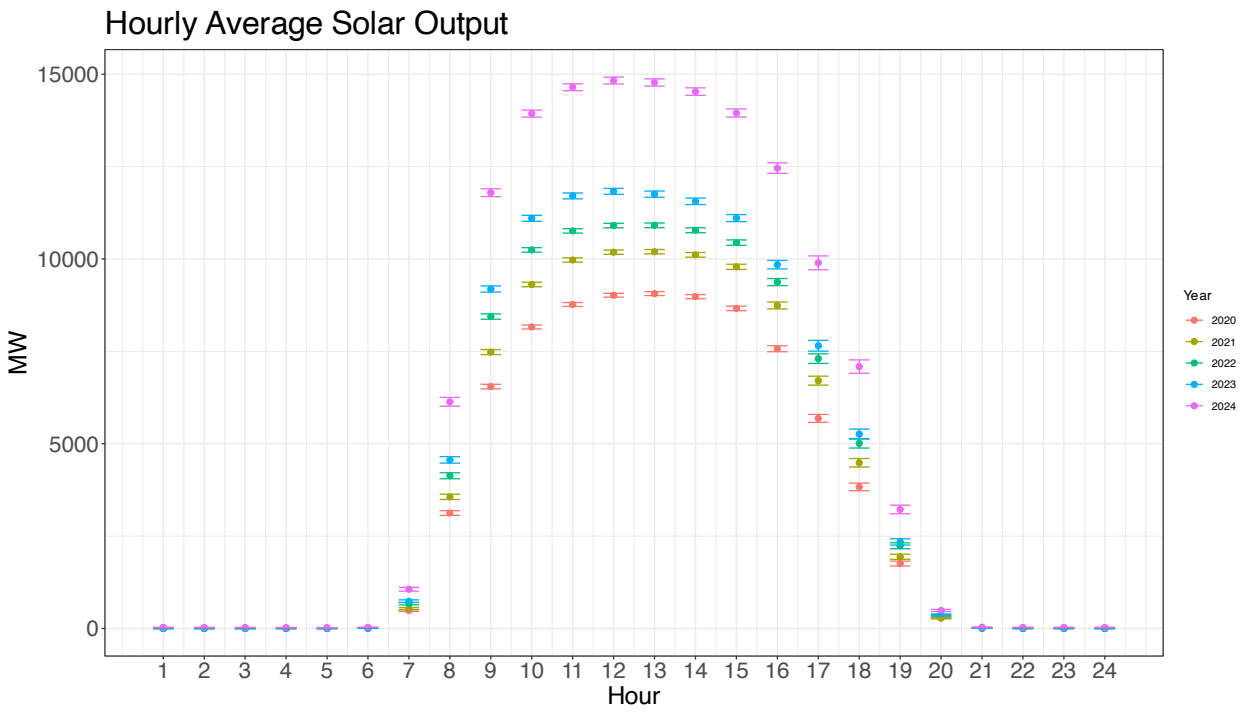


Figure ii: Hourly average solar output by year. Data from the CAISO's production and curtailment datasets.

In California, hourly variation in load and solar generation is largely explained by the seasons. Residential electricity demand dips to its annual minimum during the state's temperate winter and spring and rises to its maximum in the summer, when residents increase air conditioning usage to avoid high temperatures. Figure iii illustrates the stark disparity between the level of peak load experienced in the summer compared to the other seasons.

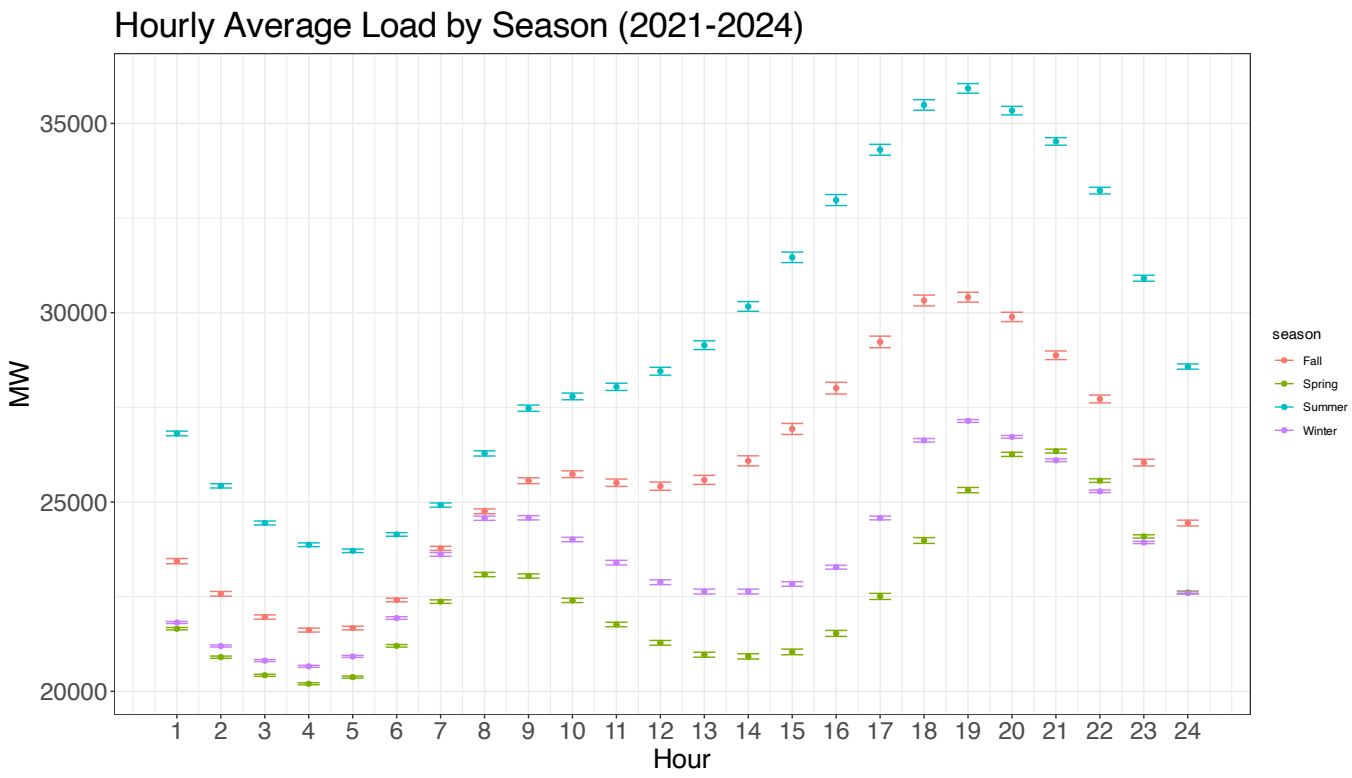


Figure iii: Hourly average load by season with 95% confidence intervals recorded in the CAISO's annual Production and Curtailment datasets

Over the four year increase in storage capacity, California has weathered many climatic events that have affected its electricity market, one being the severe drought that spanned 2021 and 2022. Chronically low precipitation depleted the states reservoirs, reflected in the anemic levels of large hydrological generation. The excessively wet winter in 2023 ended the drought and replenished the states water levels, creating a marked shift in the hourly average hydro output at all hours.

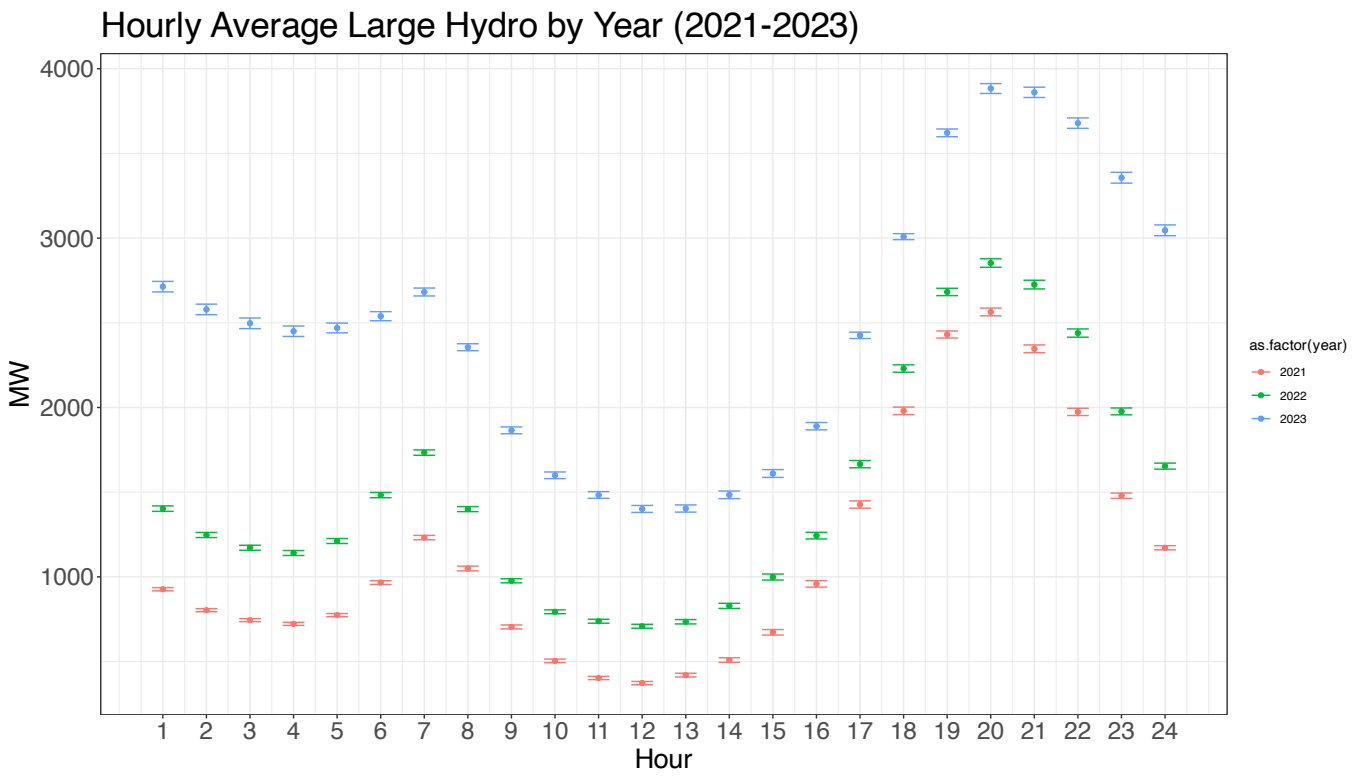


Figure iv: Hourly average large hydro generation by year recorded in the CAISO's annual Production and Curtailment datasets

Changes in hydro generation affect the supply of electricity from other dispatchable resources, namely thermal generation and imports, but may also have impacted curtailment. With less power being injected into the grid, surges in solar output are less likely to cause congestion.

The drought is unlikely to be the only event that influenced California's electricity market during the run up in battery capacity, motivating an empirical strategy that controls for unobservable factors that have affected generation outcomes over time.

Wholesale Prices

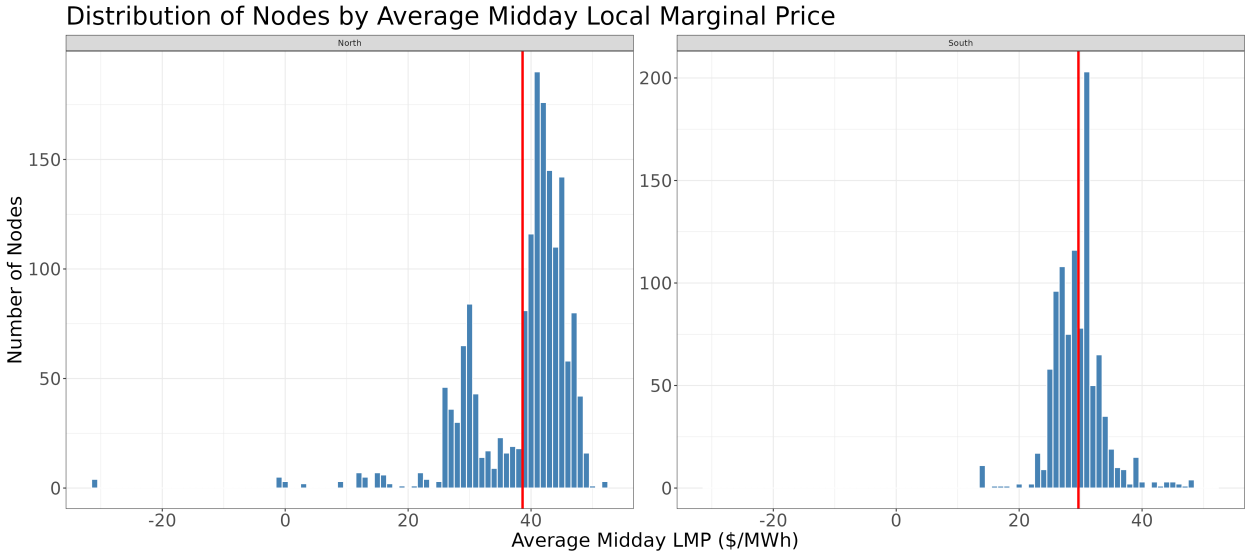


Figure v: Distribution of nodes in northern and southern California by midday (10AM - 2PM) average Day-Ahead Market Local Marginal Price from 2020 - 2024. Regional Mean DAM LMPs indicated by the vertical red lines. Data from the CAISO's OASIS. DAM LMPs from CAISO OASIS from 2020-2024.

Figure vi maps nodes with an average midday price below the regional mean in orange and those above blue. The state's solar generators are plotted in yellow and scaled by capacity (MW). The clear distinction between California's solar generating region, where prices are lower at midday due to the surplus of zero marginal cost electricity, and its coastal demand centers, where prices remain high, depicts the bottlenecks that constrain the consumption of renewably generated electricity.

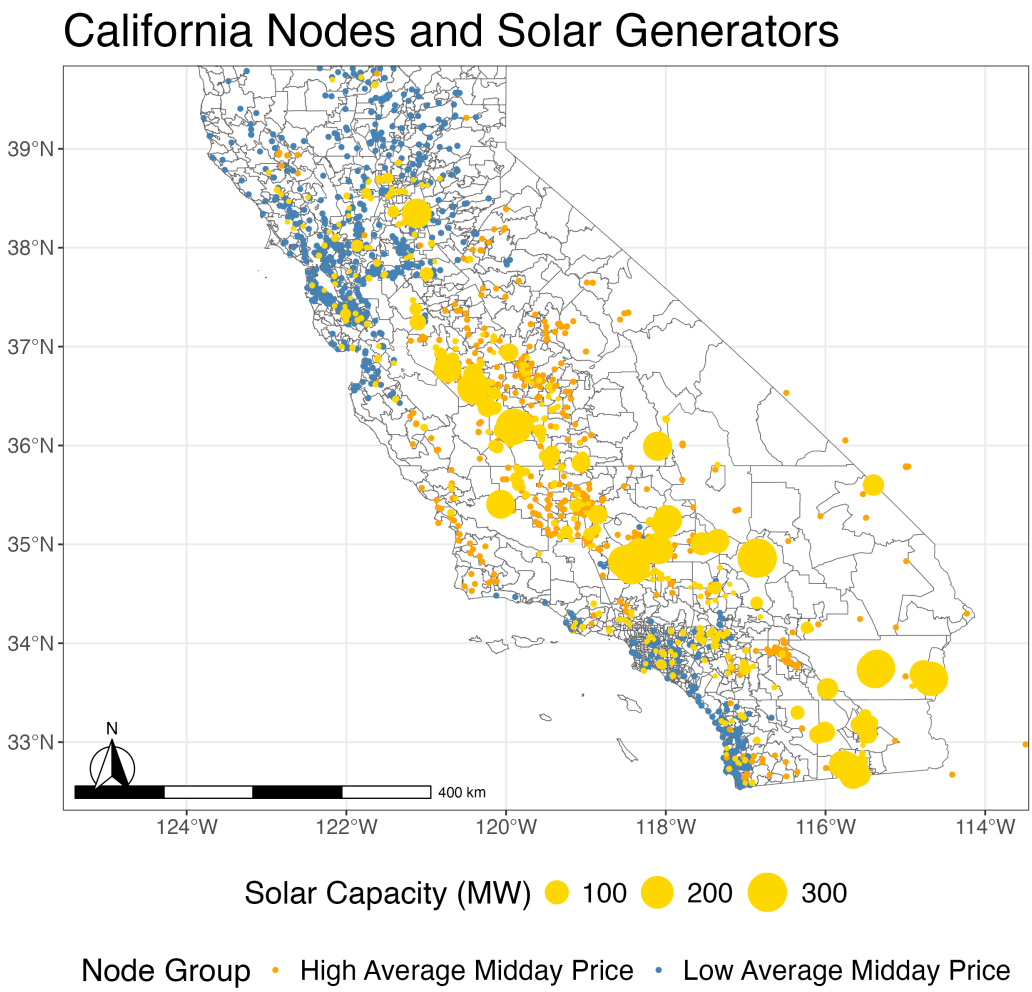


Figure vi: Nodes with average midday (10A - 2PM) Day-Ahead Market local marginal prices below the mean in orange and those above in blue. Solar generators in yellow scaled by nameplate capacity (MW). DAM LMPs from the CAISO's OASIS from 2020-2024. Solar generator locations and nameplate capacities from the EIA-860 Survey 2024.

Theoretical Model

Empirical Method

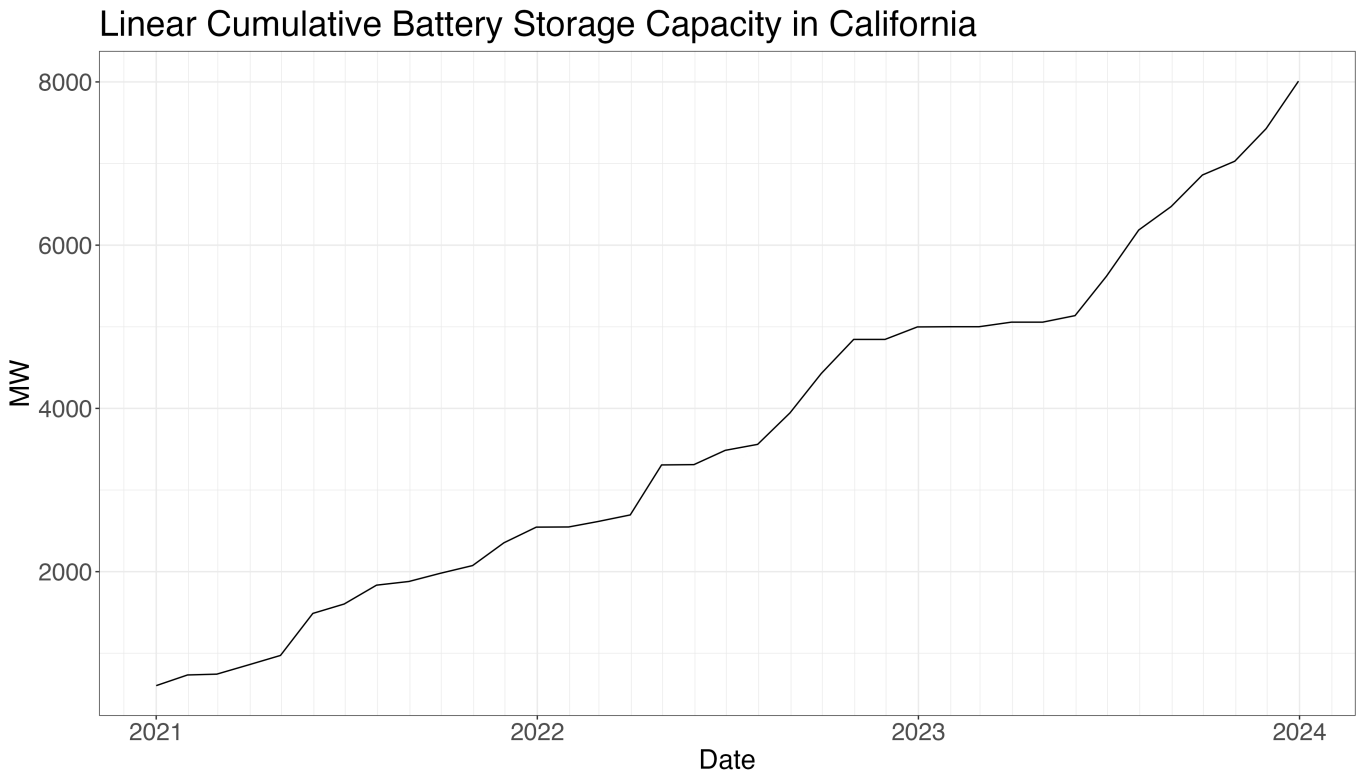


Figure vii: Monthly linear cumulative storage capacity. Storage capacity and first operating month recorded in the EIA-860 Survey.

The group partial R squared of instrument and its interactions indicates that the model has the greatest power to predict battery charge and discharge from 10 am to noon, when solar generation reaches its daily peak and batteries draw the most power from the grid. I also include the early afternoon hours from 1 to 2 pm in my analysis since solar curtailment peaks on average sometime after noon.

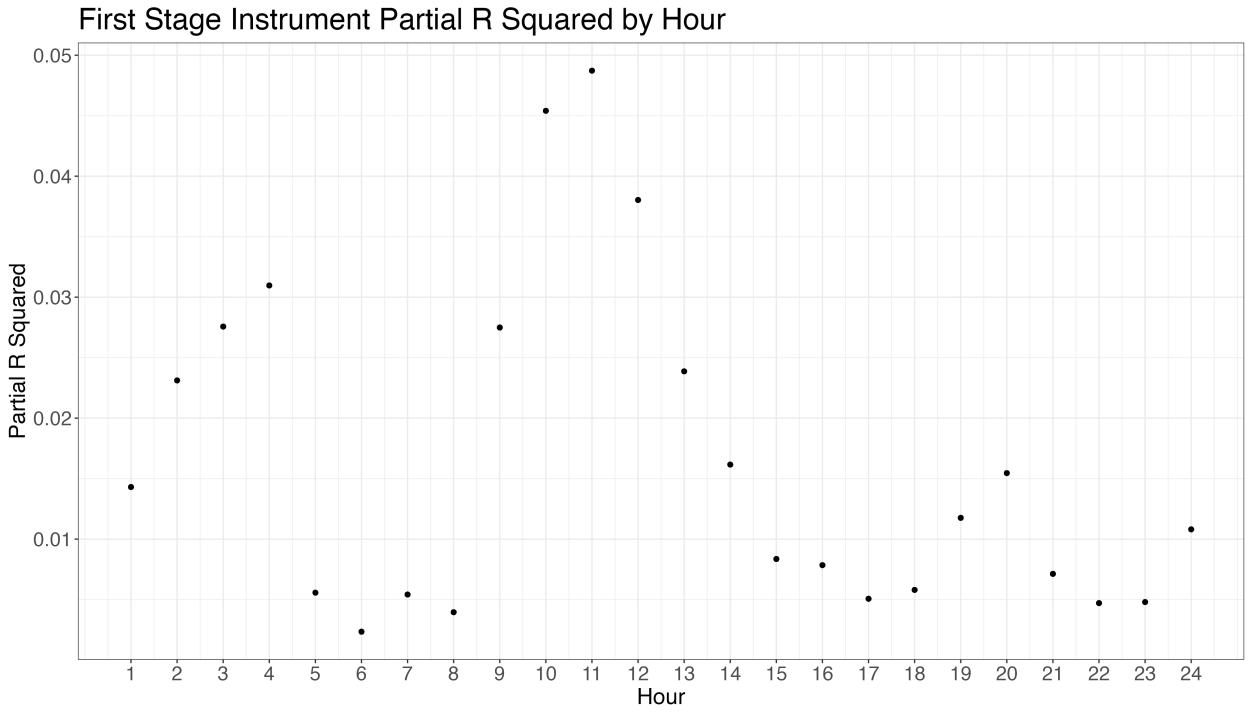


Figure viii: First stage partial R squared of the instruments.