The value of Community Solar and Storage in CAISO

April 2025

Prepared for Coalition for Community Solar Access

Agenda

Community Solar and Storage can produce savings to covers its costs, while also delivering benefits to all Californians

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Bills

Community Solar and Storage can reduce Californian power system costs by 0.6%, a **$6.5bn savings** over 20 years

- Electricity prices: **-$4.2bn reduction**
- Resource Adequacy: **-$4.6bn reduction**
- Transmission & Distribution: **-$0.91bn reduction**
- Capital costs: **+$3.2bn increase**

Reliability

Community Solar and Storage means California communities are **more self sufficient in electricity generation**

- Less reliant on transmission infrastructure to deliver power by **2%**
- Less reliant on out-of-state electricity net imports by **13%**
- Enables the electricity grid to run reliably with lower investment in transmission and distribution infrastructure

Environment

Community Solar and Storage **reduces California electricity sector emissions**

- Emissions reduction by **1.8%** within state
- Less reliant on gas generation to firm the system by **2.5%**

1) For this study, the California electricity system refers to the territory covered by the California Independent System Operator (CAISO).

Key findings

- Community Solar and Storage allows participants to subscribe to local solar and battery farms and receive credits on their electricity bills
- This study quantifies the impact of adding Community Solar and Storage on California ratepayers
- The analysis employs established electricity modeling techniques, including Capacity Expansion Modeling, Production Cost Modeling, and Power Flow Security-Constrained Economic Dispatch (SCED), to compare market outcomes from adding community projects
- This study finds that adding 5.4GW of Community Solar and Storage in California can have the following impacts:
  - Community Solar and Storage can produce **total electricity system cost savings for Californians**
  - The estimated **$6.5bn savings to ratepayers** over 20 years are enabled by:
    - **Lower electricity prices** – By locating close to electricity customers, community projects can bypass transmission constraints, displacing gas generation, which can reduce electricity prices by $4.2bn
    - **Lower spending on Resource Adequacy (RA)** – By including storage, community projects can supply electricity during the evening net peak, reducing capacity required for RA and associated costs of $4.6bn
    - **Lower spending on electricity transmission and distribution -** Community projects situated locally to customers can reduce transmission utilization by 2%, reducing line upgrade spending by $0.91bn
    - The **cost savings exceed the incremental capital costs** of +$3.2bn of community-scale projects, as compared to utility-scale projects[2]
  - The cost savings identified are additive. Cost savings can be allocated to subscribers of Community Solar and Storage projects in a way that allows **non-subscribers are no worse off**
  - In addition to cost savings, community projects allow the California electricity system to be **less reliant on out-of-state electricity net imports** by 13%, **less reliant on gas** generation by 2.5% and **lower CO_2 emissions** by 1.8%
  - Community projects enable for the reliable and cost-effective operation of the grid even when transmission investment is reduced or delayed
- Conclusion: The findings from this study suggests Community Solar and Storage can produce savings to cover its costs, while also delivering reliability and emissions benefits to all Californians

1) For this study, the California electricity system refers to the territory covered by the California Independent System Operator (CAISO). 2) This analysis assumes Community Solar and Storage projects are 1.32 times more expensive than utility-scale projects – an assumption based on CPUC IRP inputs, where distributed solar is modeled using NREL cost estimates for 200 kW systems. This assumption may be conservative if anticipating lower costs for community projects (e.g. improved economics from economies of scale).

This study adds 5.4GW of Community Solar and Storage throughout the California ISO territory

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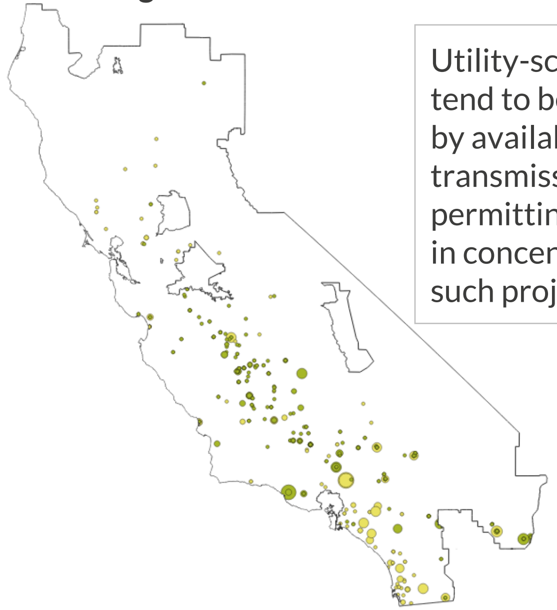
Community Solar and Storage projects added by 2033

Community-scale projects can be evenly spread out, including rural and urban areas, allowing many projects to be close to customers

Utility-scale solar and storage in the Base case in-lieu of community projects



Utility-scale projects tend to be constrained by available transmission and permitting, resulting in concentrations of such projects

Community projects[1] Utility-scale solar Utility-scale storage

Community Solar and Storage case

- 5.4GW of community projects are distributed throughout CAISO territory[2]
- As small and diverse projects, community projects can locate throughout the Central Valley and near urban areas including LA, San Diego, and San Francisco
- Community-scale projects can cost more than the utility-scale versions. The addition of 5.4GW of such projects results in an estimated incremental capital cost of $3.2bn when compared to the utility-scale equivalents

Base case, without community projects

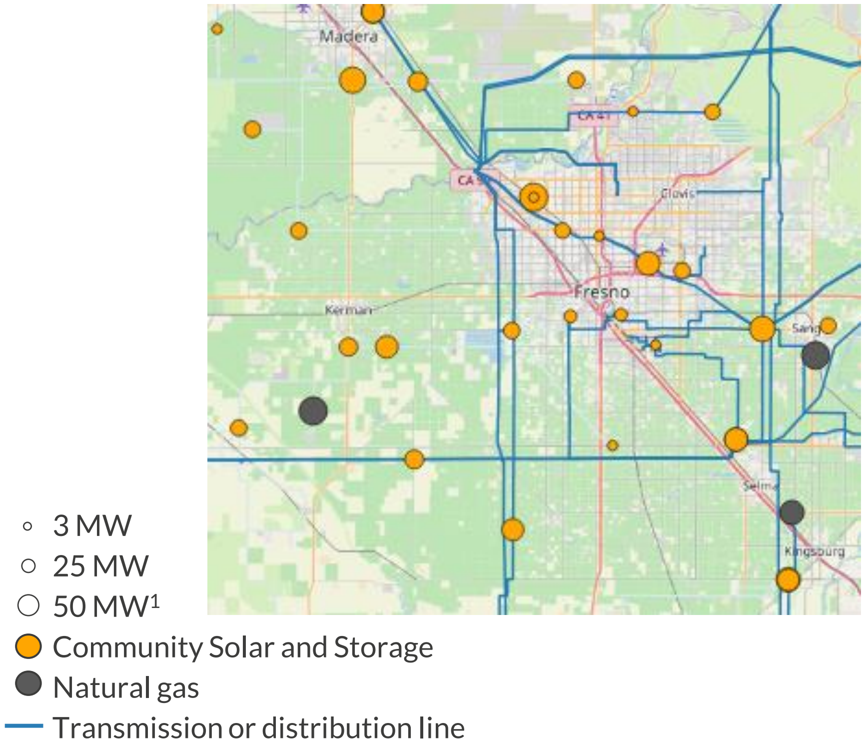
- In the absence of community projects, a commensurate amount of utility-scale solar and storage projects are added[3]
- Utility-scale solar is expected to concentrate in the Central Valley, and utility-scale storage around Southern California
- Few utility scale projects are expected around the Bay Area and Sacramento due to less favorable project economics and transmission constraints

1) Circle size on map represents project size. Smaller projects connected to the same substation are aggregated and shown as a single circle. 2) Allocation of such projects subject to constraints: proportional to net downstream load, within Local Reliability Area (LRA) regions, 80/20 rural-urban split, minimum project size of 3MW. 3) Project entry modeled based on economic optimization subject to available transmission.

Sources: Aurora Energy Research

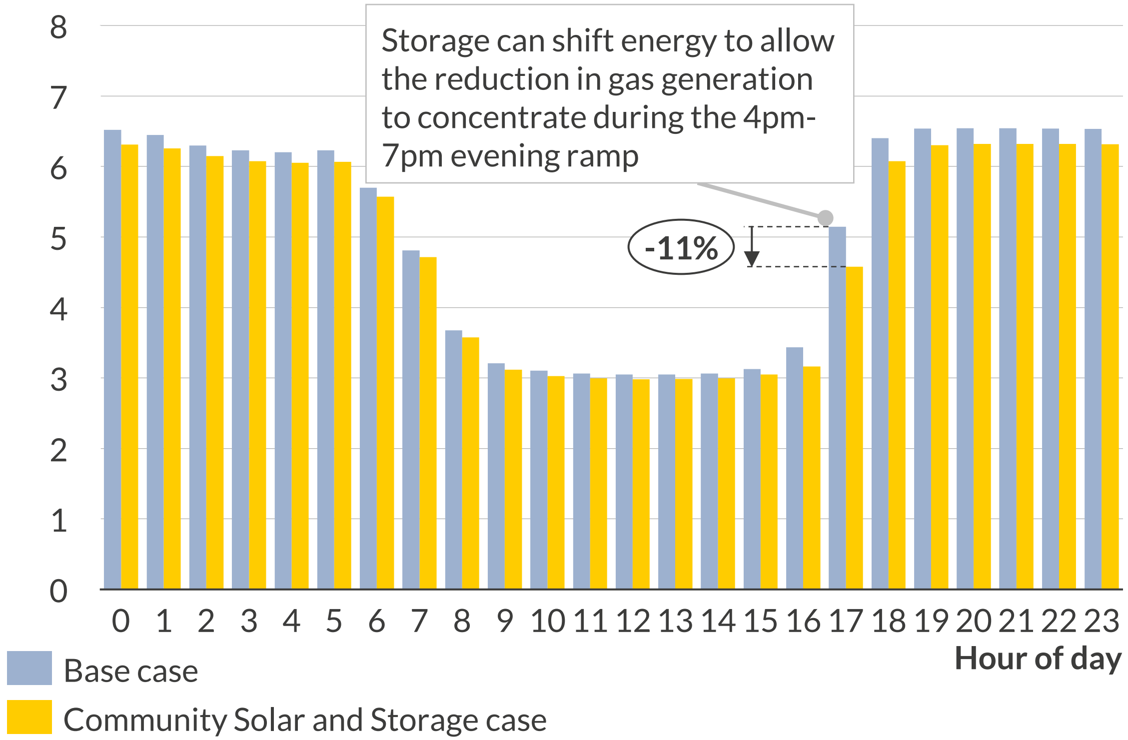
In being close to customers, community projects can bypass transmission constraints and displace gas generation

Potential Community Solar and Storage projects in Fresno by 2033



CAISO-wide natural gas generation – Community vs Base

Daily average in 2033, GW



- Community projects are smaller and can be spread out throughout California
- With some community-scale projects located close to customers e.g. in urban areas, community solar and storage could reduce the need for gas generation located upstream of congested transmission lines

- Aurora's modeling shows the Community Solar and Storage case with 2.5% lower gas generation and 13% lower out-of-state electricity net imports compared to the Base case
- The lower gas generation results in $4.2bn lower electricity prices and a 1.8% reduction of California within state CO_2 emissions over 2025-2045

1) Smaller projects connected to the same substation are aggregated and shown as a single circle.

Sources: Aurora Energy Research

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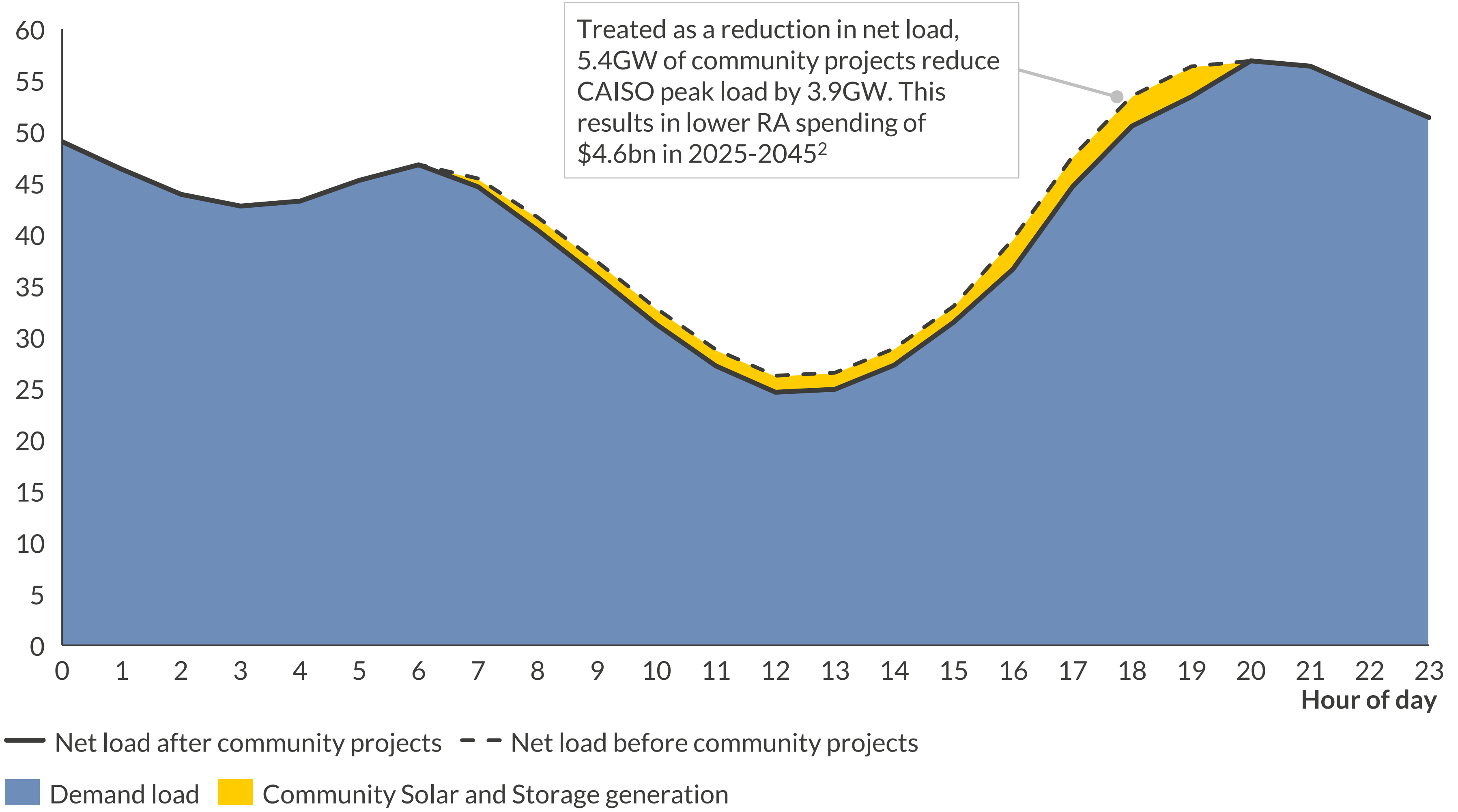
In serving downstream electricity demand, Community Solar and Storage could reduce Resource Adequacy requirements

Net demand load at an example substation: Malaga substation – August 5th, 2033

MW[1]



- The Resource Adequacy (RA) program requires Load Serving Entities (LSEs) to procure adequate energy resources to meet their expected peak-load plus a planning reserve margin (PRM)
- The Community Solar and Storage projects, when incentivized appropriately, can store solar energy for use during the evening net peak
- By siting the Community Solar and Storage projects where there is downstream demand, these projects could reduce the net load for LSEs, potentially reducing RA spending

1) Demand load is net of rooftop solar. 2) Analysis assumes cost savings from System Resource Adequacy procurement requirement – this analysis could prove conservative where Community Solar and Storage is able to displace more scarce and typically more costly Local Resource Adequacy procurement requirements.

Sources: Aurora Energy Research

Community projects allow electricity customers to be less reliant on transmission lines, reducing transmission utilization and spending

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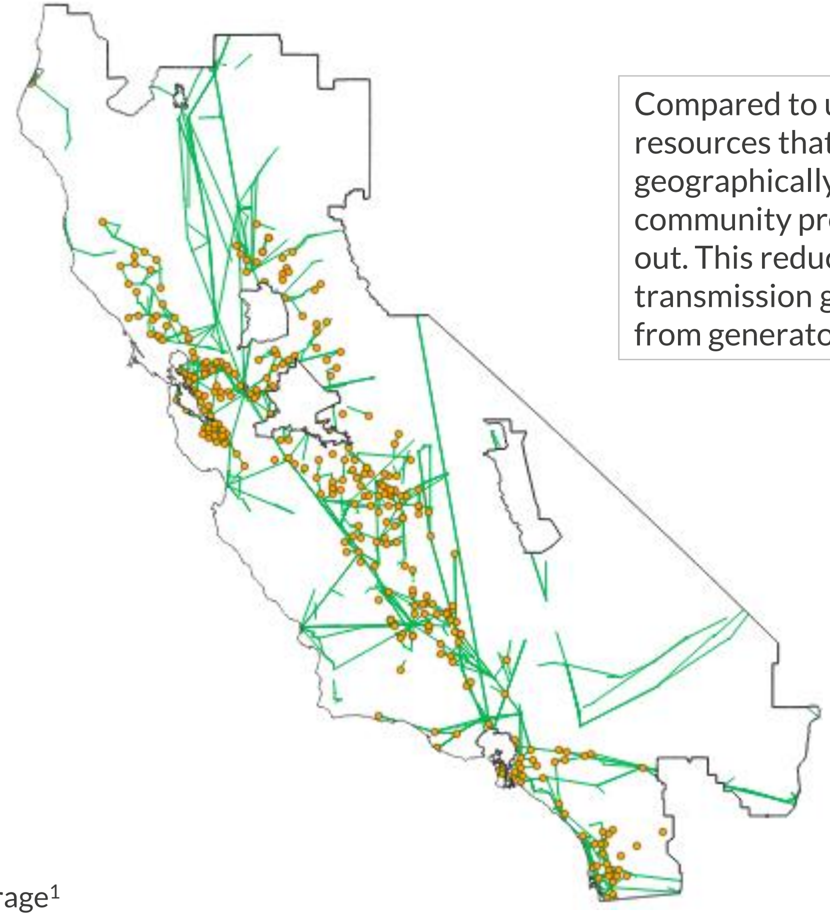
Reduction in transmission utilization in Community Solar and Storage case - 2033



Compared to utility-scale energy resources that tend to be geographically concentrated, community projects are evenly spread out. This reduces the reliance on the transmission grid to move electricity from generators to customers

Community Solar and Storage[1]

Lines with decreased flow, compared to Base case

- The resulting less congested grid allows lower requirements for upgrading transmission lines. In the Community Solar and Storage case, the reduction in transmission utilization allows lower spending in line upgrades of $0.91bn in 2025-2045
- Transmission is a major limiting factor for building new renewable energy projects. The addition of Community Solar and Storage allows for greater potential for building renewables at a quicker pace

1) Smaller projects connected to the same substation are aggregated and shown as a single circle.

Sources: Aurora Energy Research

Community projects enable for the reliable and cost-effective operation of the grid with delayed or lower transmission investment

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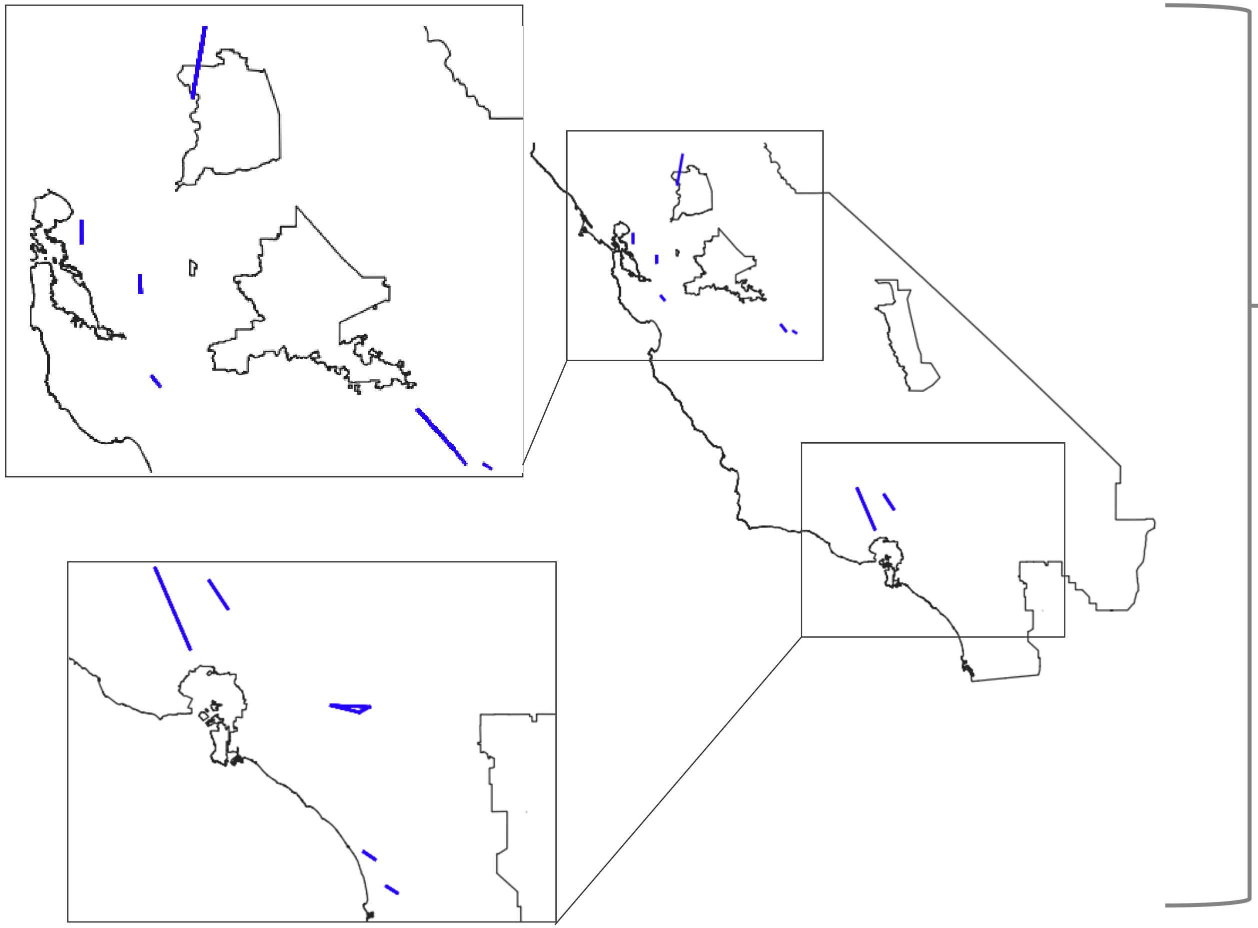
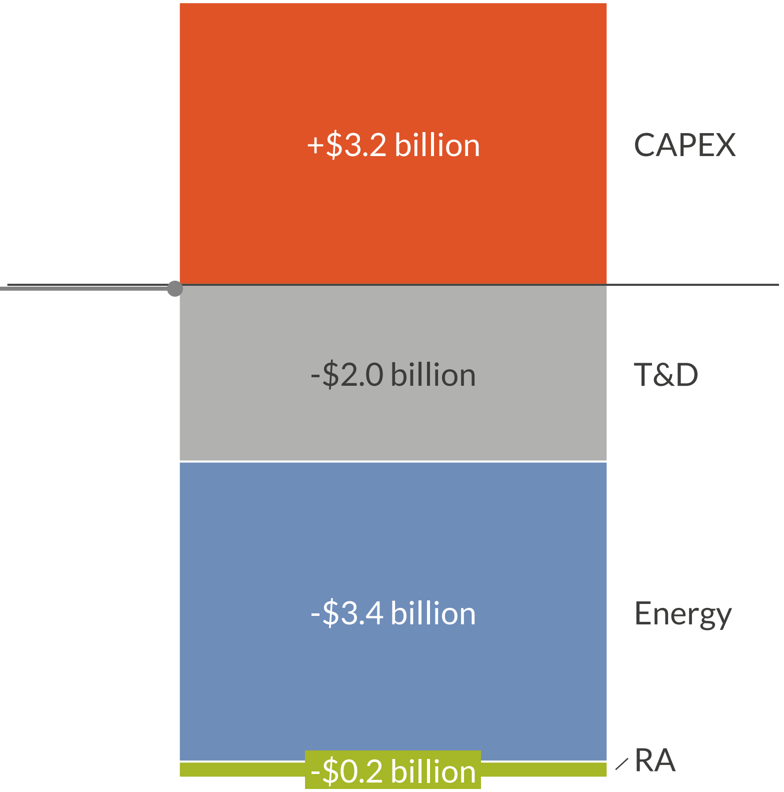
Community Solar and Storage + Low Transmission Scenario: Assumed canceled TPP line upgrades[1]



Difference in total system cost: Community Solar and Storage + Low Transmission Scenario less Base Case



Total savings: -$2.4 billion

Community projects continue to provide net savings to the Californian system with reduced T&D investment

1) Transmission upgrades reduced or delayed in the low transmission scenario.

Sources: Aurora Energy Research

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3 scenarios were designed to investigate the impacts of adding 5.4GW of community-scale projects into the CAISO system

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The initial capacity mix aligns with CPUC's Baseline Resource List, updated in 11/2024. In the High Community Solar and Storage (CSS) Cases, 5.4GW of community-scale projects are added to evaluate how they affect future economic capacity build and overall system performance

As per Scenario 1 Base Case - unless otherwise indicated		Scenario 1 – Base Case	Scenario 2 – High Community Solar and Storage	Scenario 3 – High Community Solar and Storage + low transmission
Demand		Match CEC 2022 IERP/2023 IRP		
Commodities	Gas price	Match 2022-23 IRP		
	Carbon price	Match 2022-23 IRP		
Technology	Thermal, wind, hydro, other renewables capacity	Start with existing and in-development resources, add offshore wind in accordance with IRP planning, allow Aurora model to economically build additional capacity	Start with existing and in-development resources, 5.4GW of community solar and storage allow Aurora model to economically build additional capacity	Match Scenario 2 capacity mix
	Utility-scale solar + BESS	Start with existing and in-development resources in accordance with IRP planning, allow Aurora model to economically build additional capacity	Start with existing and in-development resources, 5.4GW of community-scale projects, allow Aurora model to economically build additional capacity	Match Scenario 2 capacity mix
	FTM community solar + storage projects	Start with existing and in-development resources, allow Aurora model to economically build additional capacity	Add 5.4GW of community solar + tech projects, deployed at ~1GW/year from 2026-2032, allow Aurora model to economically build additional capacity	Match Scenario 2 capacity mix
	Capital, variable O&M, fixed O&M costs	Match 2023 IRP		
Policy	Transmission upgrades	Match 2023-24 TPP budget		Cancel 16 TPP projects, estimated at $1.1B
	Tax credits	Match 2022-23 IRP assumption that solar and onshore wind receive $26/MWh PTC while offshore wind, batteries, geothermal, biomass receive 30% ITC	Community-scale projects receive 30% ITC	

Sources: Aurora Energy Research

5.4GW of Community Solar and Storage projects were allocated across the CAISO system to meet local load

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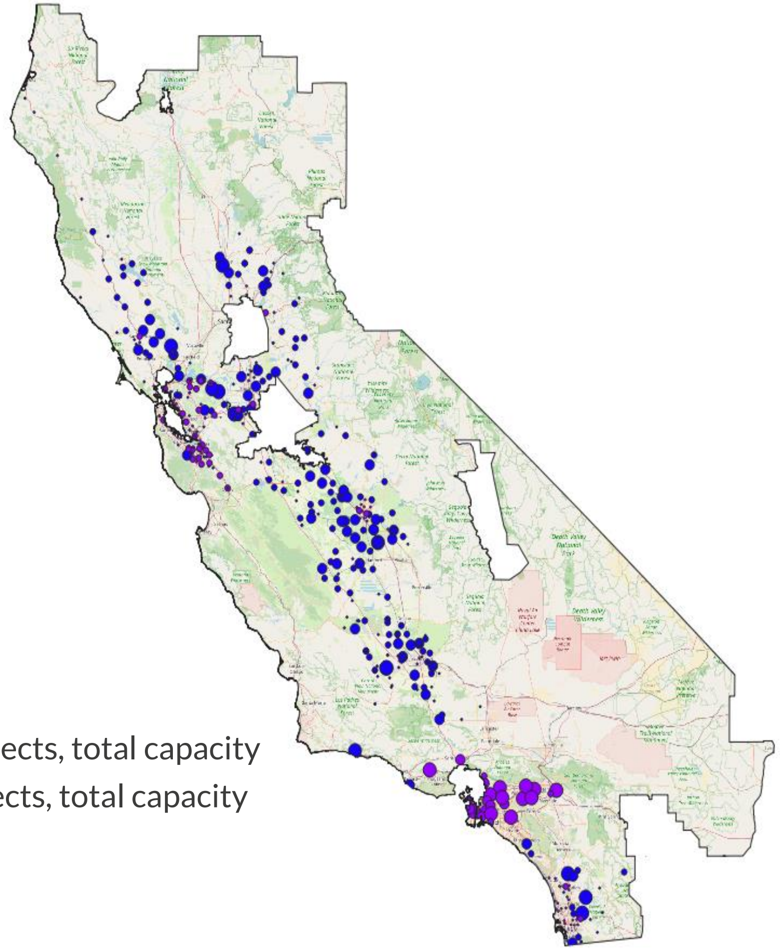
Mapping of community-scale projects in High CSS Case



- Urban community projects, total capacity
- Rural community projects, total capacity
- 3 MW
- 50 MW
- 100 MW

Community-scale project allocation process

1) **Calculated net load minus generation at each node**
   a) The average regional (NP15, SP15, ZP26) 2030 demand (MW) during July, August, and September from 5-9pm was calculated[1]
   b) Regional load was distributed to individual nodes based on the 2023 WECC snapshot
   c) Industrial load was removed from nodes using CEC's sector-based electric load forecasts[2]
   d) The remaining load at each node was determined by subtracting forecasted 2030 installed capacity (MW) from the average peak hours load, after adjusting for industrial load[3]
2) **Assign community-scale projects**
   a) Assigned Community Solar and Storage project capacity to spread capacity proportional to remaining load at nodes while adhering to the following constraints:
      I. Community-scale projects geographically constrained to Local Reliability Areas (LRA's)
      II. An 80/20 rural-urban target
      III. Minimum project size of 3MW
      IV. Maximum project size of 5MW[4]
      V. <u>5.4GW total Community Solar and Storage capacity addition</u>

1) Using 2022 IEPR 2) Industrial load from CEC's California Energy Demand Update 2022 Baseline Forecasts 3) Forecasted 2030 installed capacity based on CPUC's updated Baseline and In-development resources as of 11/2024 4) Circle size on map represents project size. Smaller projects connected to the same substation are aggregated and shown as a single circle.
Sources: Aurora Energy Research

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Combined capital expenditure, wholesale power, ancillary, RA, and T&D spend are 0.6% lower in High CSS Case compared to Base Case

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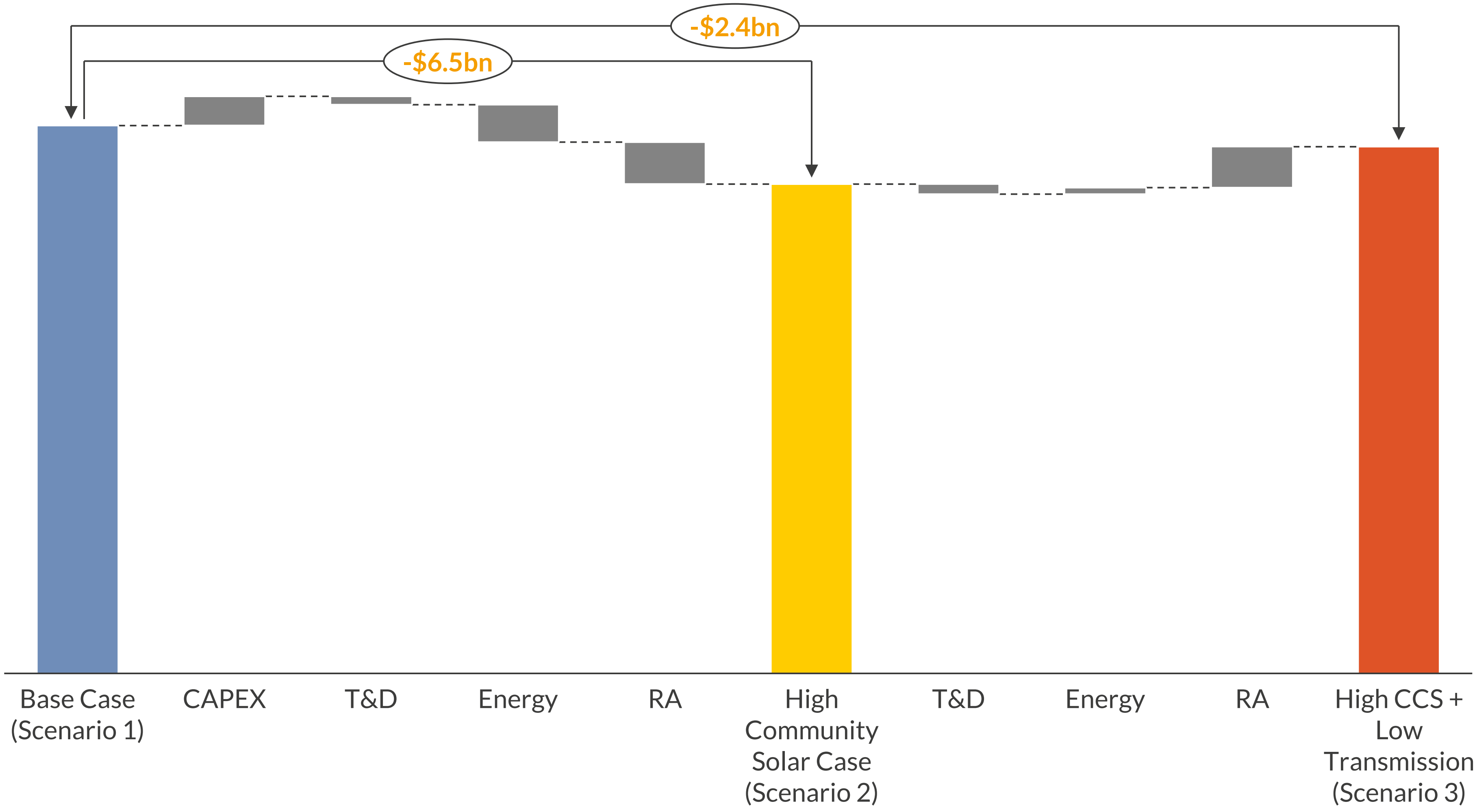
Illustrative breakdown in the difference in capital spend, resource adequacy, wholesale power and T&D spend 2025-2045[1]



- Initial results show 0.6% decrease in system costs in High Community Solar and Storage Case, compared to Base Case from 2025 to 2045
- Scenario 3 demonstrates that community solar and storage delivers system cost savings and reliability benefits even if planned TPP transmission upgrades face delays or cancellations

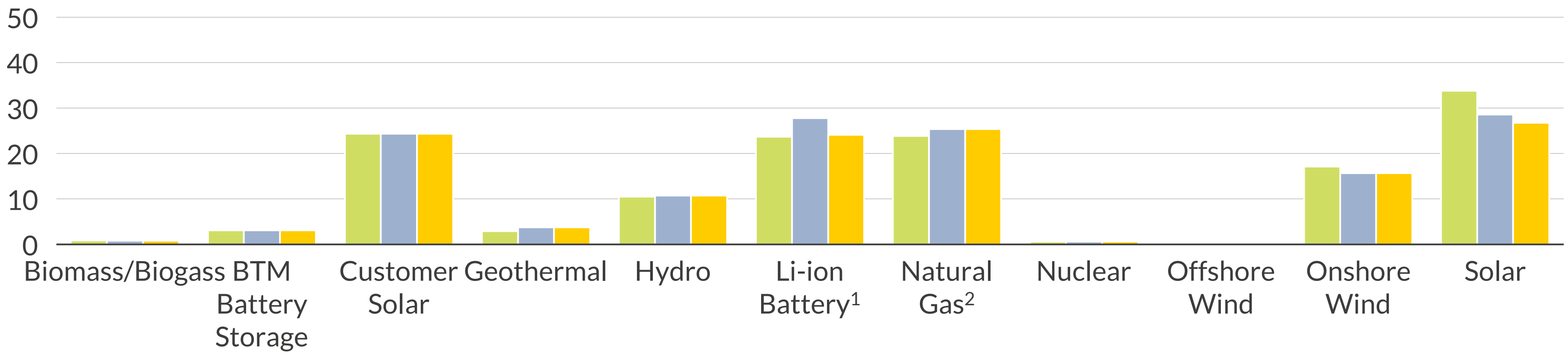
	Scen 2 less Scen 1	Scen 3 less Scen 1
Energy	-$4.2B	-$3.4B
RA	-$4.6B	-$0.20B
T&D	-$0.91B	-$2.0B
Capex	+$3.2B	+$3.2B
Net savings	-$6.5B	-$2.4B

1) Illustrative breakdown of differences in the chart – please see table to the right for numbers on the difference in energy, RA, T&D and Capex spend across scenarios.

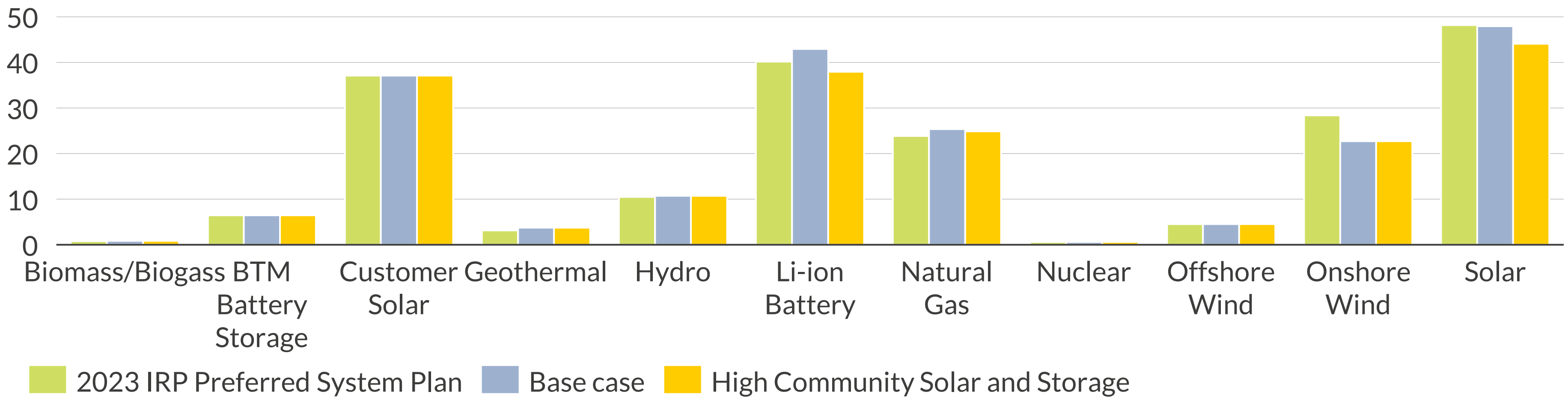
Sources: Aurora Energy Research

In the High Community Solar and Storage Case, CSS projects primarily replace utility-scale storage and solar

2030 capacity stack
GW



2040 capacity stack
GW



- All scenarios started with existing and in-development resources from CPUC's reportedd baseline
- In the High Community Solar and Storage Case, 5.4GW of community solar and storage were introduced by 2032
- Additional capacity additions forecasted based on economic model solve and planning reserve margin constraint
- The strong alignment between the IRP 2023 Preferred System Plan Portfolio and the modeled Base Case and High Community Solar and Storage Case Portfolios—in both the type and quantity of new resources added—demonstrates the consistency of this study with the state's planning framework

1) 4GWh of storage duration is shown as 1GW of capacity. 2)The small difference in natural gas amounts is due to the fact that the CPUC added slightly more gas to its baseline after adopting the 2023 PSP, and Aurora used this updated baseline as the starting point for its own modeling
Sources: Aurora Energy Research

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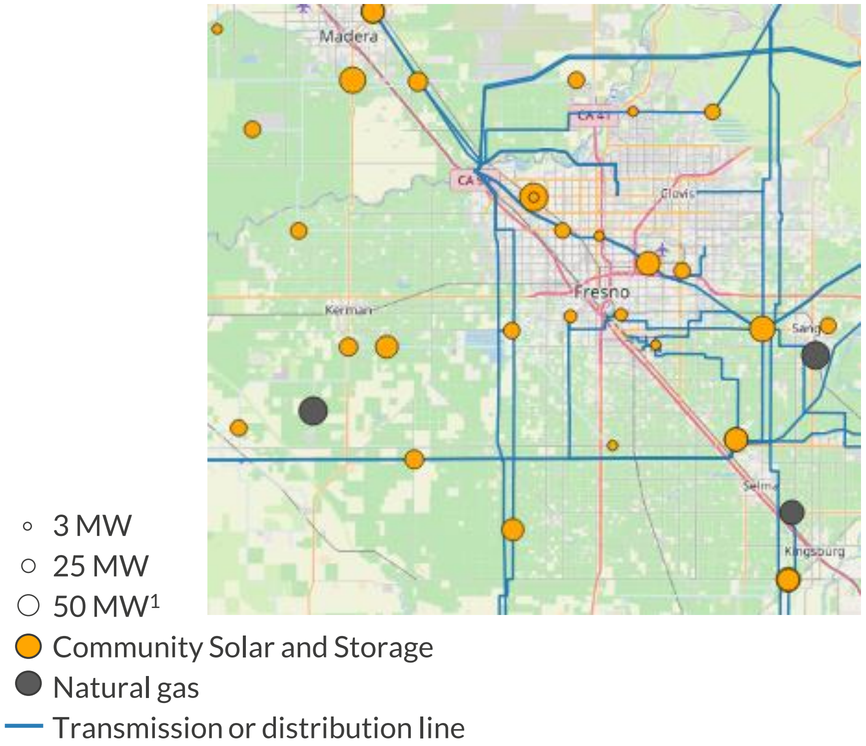
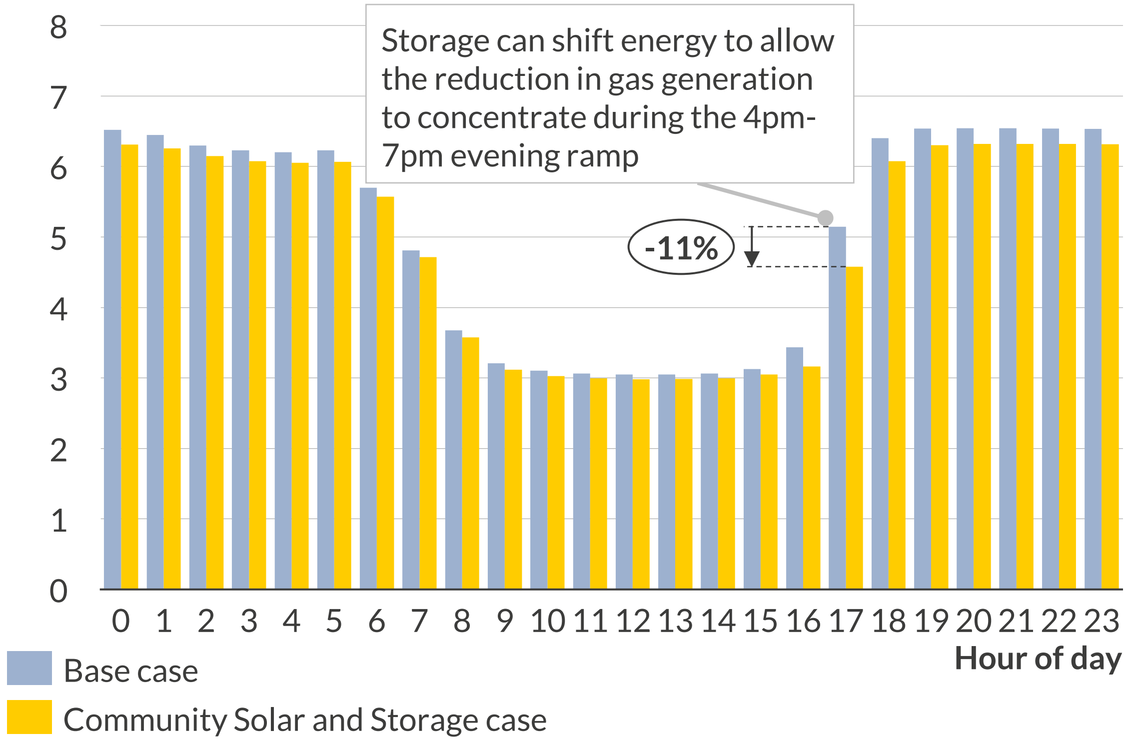
In being near customers, CSS's can bypass transmission constraints and displace gas, leading to energy cost savings

Potential Community Solar and Storage projects in Fresno by 2033



CAISO-wide natural gas generation – Community vs Base
Daily average in 2033, GW



- Community projects are smaller and can be spread out throughout California
- With some community-scale projects located close to customers e.g. in urban areas, community solar and storage could reduce the need for gas generation located upstream of congested transmission lines

- Aurora's modeling shows the Community Solar and Storage case with 2.5% lower gas generation and 13% lower out-of-state electricity net imports compared to the Base case
- The lower gas generation results in $4.2bn lower electricity prices and a 1.8% reduction of California within state CO_2 emissions over 2025-2045

1) Smaller projects connected to the same substation are aggregated and shown as a single circle.

Sources: Aurora Energy Research

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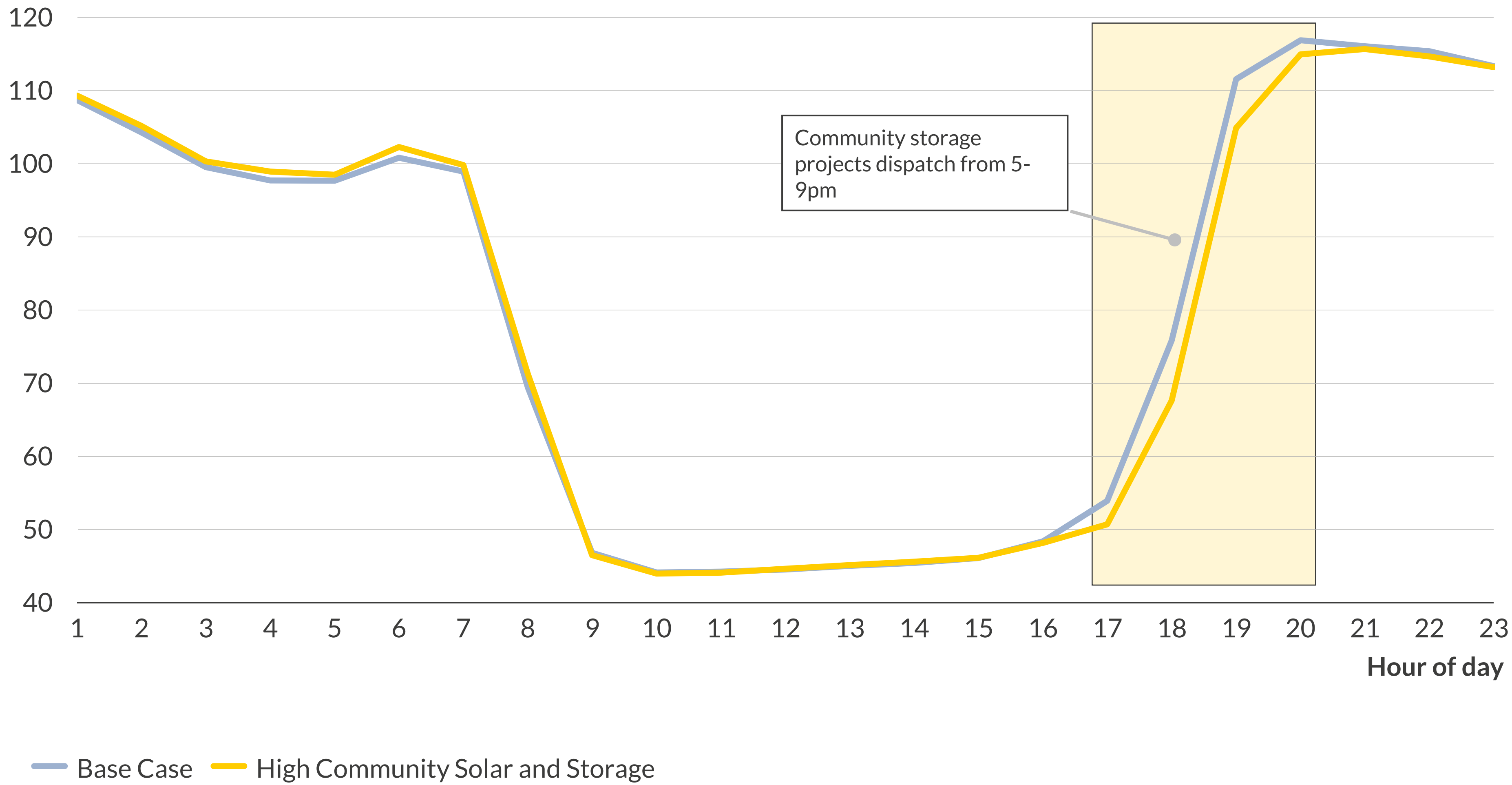
Community storage dispatches from 5-9pm, displacing gas generation and decreasing peak evening electricity prices

Average demand weighted Locational Marginal Price 2033, September – High Community Solar and Storage vs Base Case
$/MWh, nominal



- Community storage dispatches during hours of 5-9pm
- The lower gas generation results in $4.2bn lower spend on electricity over 2025-2045

1) ATC wholesale power price is the “Time-Weighted Average” or “Baseload” price.

Sources: Aurora Energy Research

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In serving downstream electricity demand, Community Solar and Storage could reduce Resource Adequacy requirements

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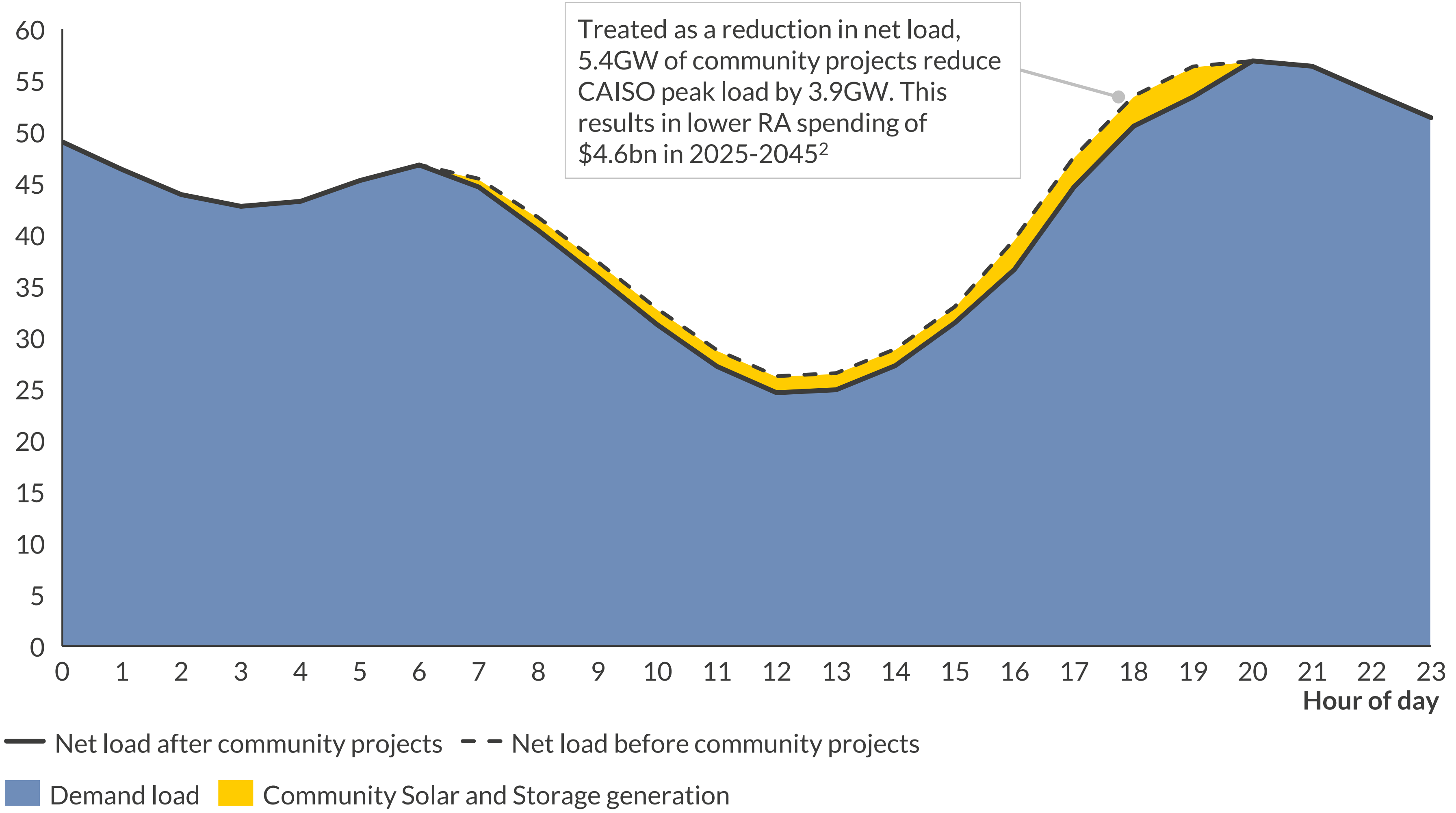
Net demand load at an example substation: Malaga substation – August 5th, 2033

MW[1]



- The Resource Adequacy (RA) program requires Load Serving Entities (LSEs) to procure adequate energy resources to meet their expected peak-load plus a planning reserve margin (PRM)
- The Community Solar and Storage projects, when incentivized appropriately, can store solar energy for use during the evening net peak
- By siting the Community Solar and Storage projects where there is downstream demand, these projects could reduce the net load for LSEs, potentially reducing RA spending

1) Demand load is net of rooftop solar. 2) Analysis assumes cost savings from System Resource Adequacy procurement requirement – this analysis could prove conservative where Community Solar and Storage is able to displace more scarce and typically more costly Local Resource Adequacy procurement requirements.

Sources: Aurora Energy Research

In the High CCS Scenario, community-scale projects were treated as load modifiers which decreased PRM by ~4.5GW

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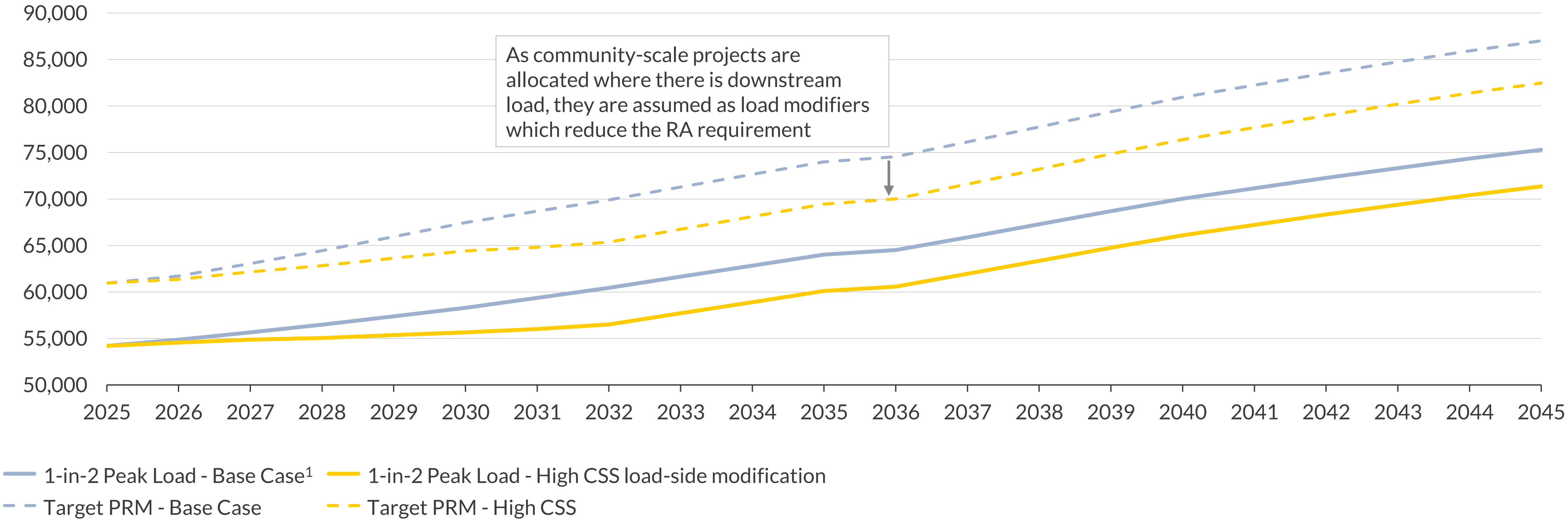
The Capacity Expansion Model builds resources to meet Planning Reserve Margin (PRM). Community Solar and Storage projects are treated as load modifiers to change capacity build-out from Base Case to High Community Solar and Storage case

5.4GW of community-scale projects x 90% discharge range x 95% expected non-outage range x 85% efficiency = 3.9GW reduction in peak load requirements

CAISO system RA requirement
MW

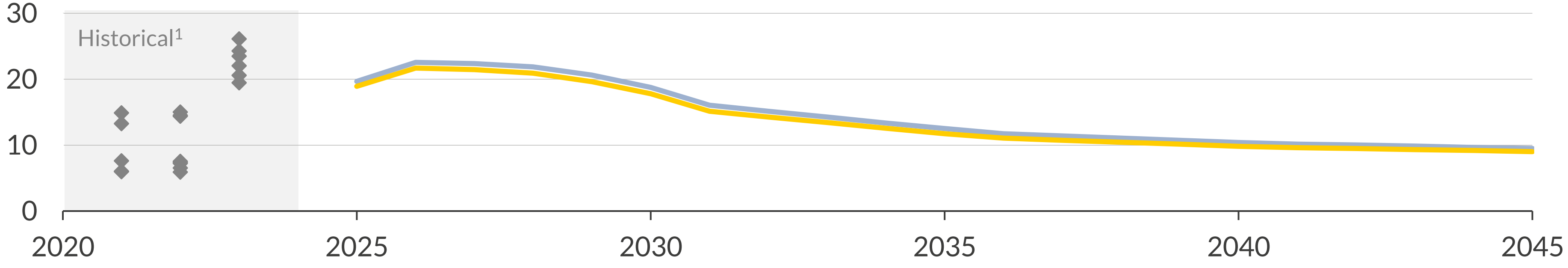


1) Gross system peak load is defined as managed net load minus hourly demand increases or decreases from BTM PV, AAEE, AAFS, BTM storage, EV charging, and TOU rates

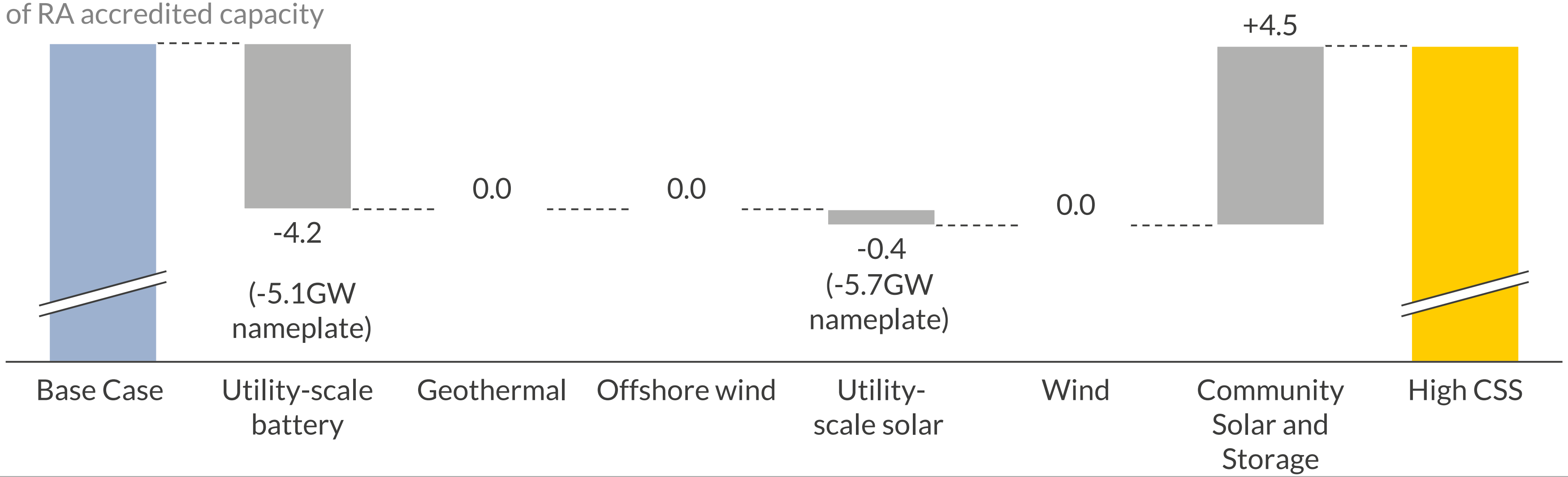
Sources: Aurora Energy Research

Lower RA prices and volume procured contribute to lower RA spend in Community Solar and Storage Case

Forecast system RA price – 4-hour BESS
$/kw-mo, nominal



Delta in new build counted capacity receiving RA payment, 2025-2040 – High Community Solar and Storage vs Base Case
GW of RA accredited capacity



1) Historic prices are sourced from self-reported FERC EQR data for battery assets with COD in 2021, 2022, 2023

Sources: Aurora Energy Research

- Community Solar and Storage projects are an additional resource available for meeting RA requirements. The additional supply of resources in the High Community Storage and Solar case provides competition that lowers the RA price
- In the High Community Solar and Storage case, community-scale projects are treated as load modifiers as the projects are located where there is downstream load
- The addition of 5.4GW of Community Solar and Storage decreases the need for about 5.1GW nameplate of utility-scale batteries and 5.7GW nameplate of utility-scale solar compared to the Base Case
- System RA cost savings are based on avoiding average RA prices. CSS projects would defer need for transactions at marginal RA price

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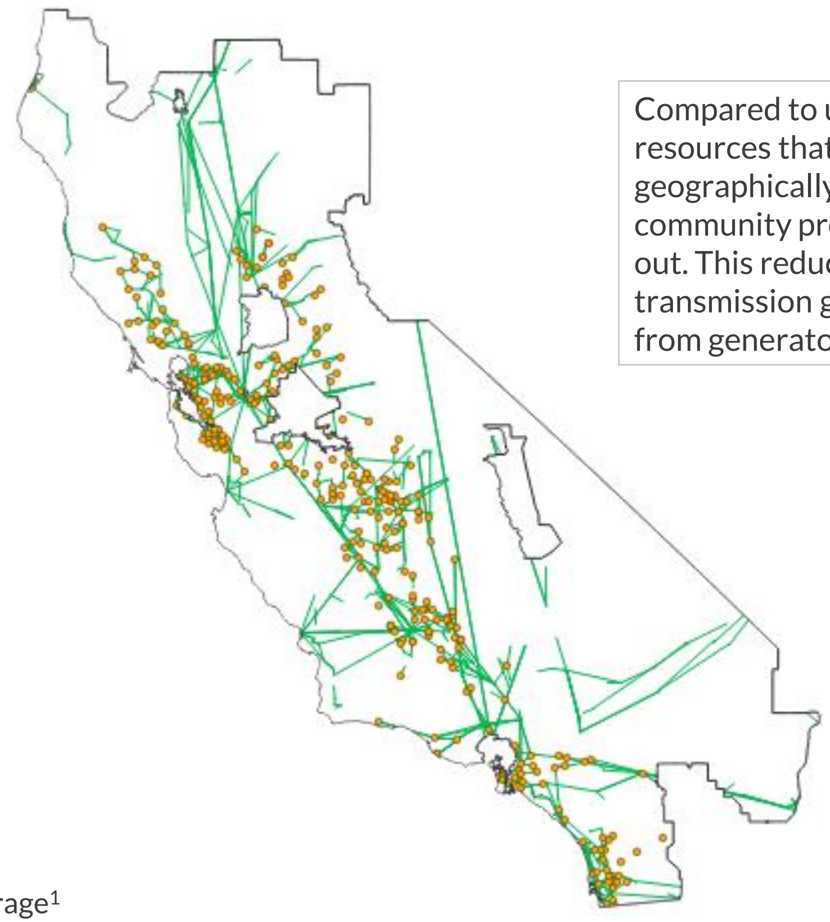
Community projects allow electricity customers to be less reliant on transmission lines, reducing transmission utilization and spending

Reduction in transmission utilization in Community Solar and Storage case - 2033



Community Solar and Storage[1]
Lines with decreased flow, compared to Base case

- The resulting less congested grid allows lower requirements for upgrading transmission lines. In the Community Solar and Storage case, the reduction in transmission utilization allows lower spending in line upgrades of $0.91bn in 2025-2045[2]
- Transmission is a major limiting factor for building new renewable energy projects. The addition of Community Solar and Storage allows for greater potential for building renewables at a quicker pace

1) Smaller projects connected to the same substation are aggregated and shown as a single circle. 2) Savings are from transmission level spending only. It was beyond the scope of this study to model distribution level spending.
Sources: Aurora Energy Research

Community projects enable for the reliable and cost-effective operation of the grid with delayed or lower transmission investment

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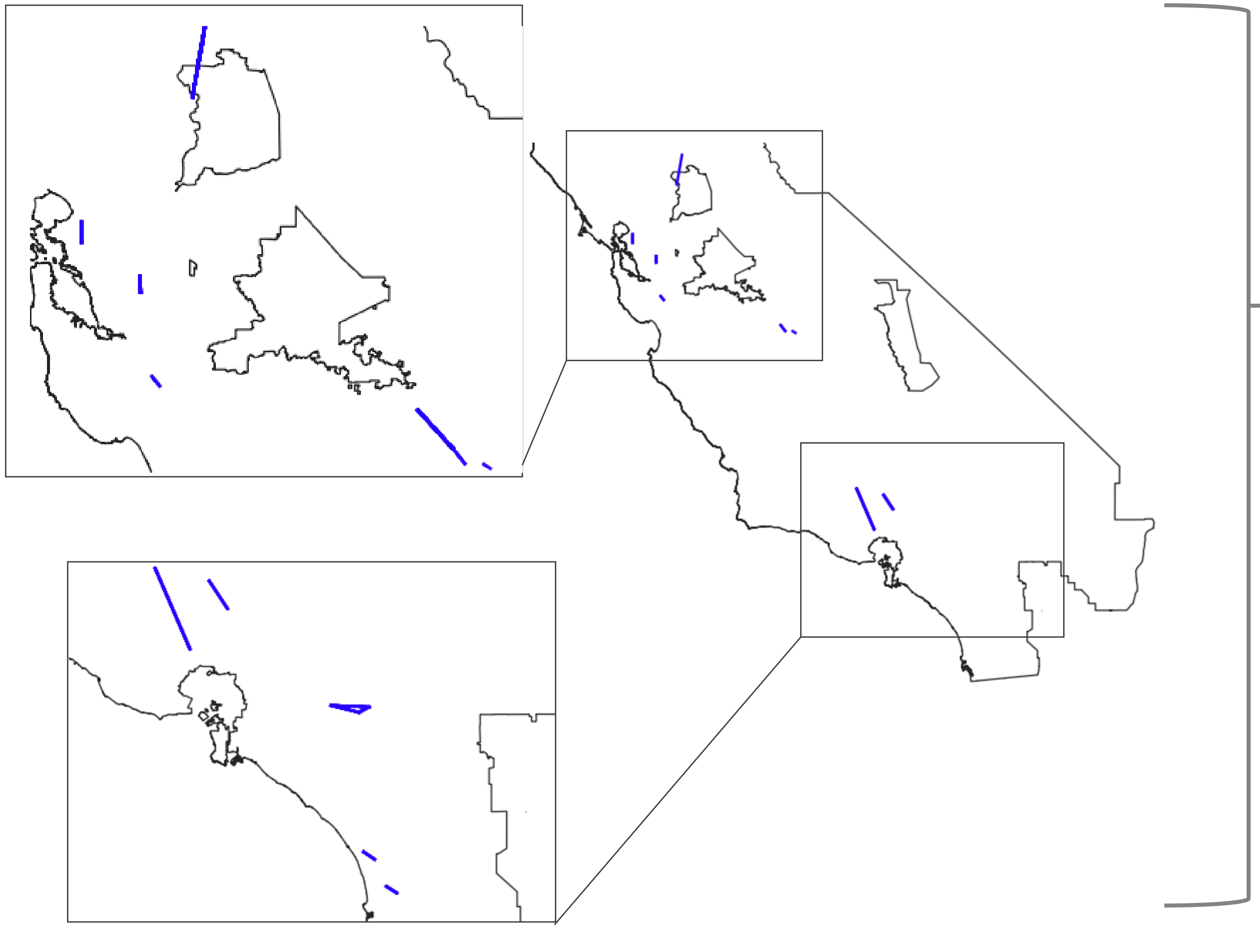
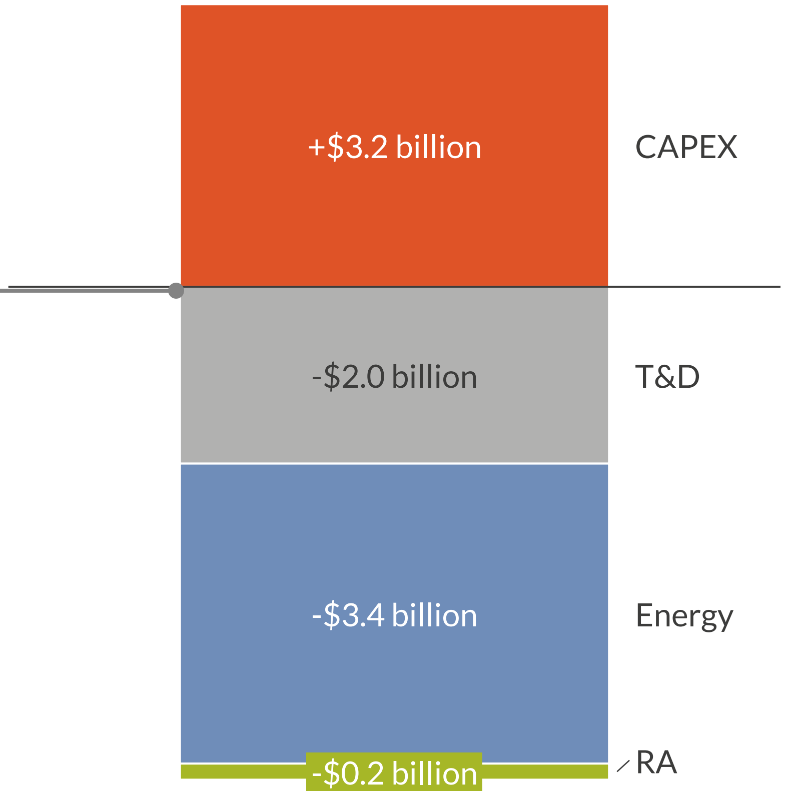
Community Solar and Storage + Low Transmission Scenario: Assumed canceled TPP line upgrades[1]



Difference in total system cost: Community Solar and Storage + Low Transmission Scenario less Base Case



Total savings: -$2.4 billion

Community projects continue to provide net savings to the Californian system with reduced T&D investment

1) Transmission upgrades reduced or delayed in the low transmission scenario.

Sources: Aurora Energy Research

Lines show decreased utilization when community solar and storage dispatch

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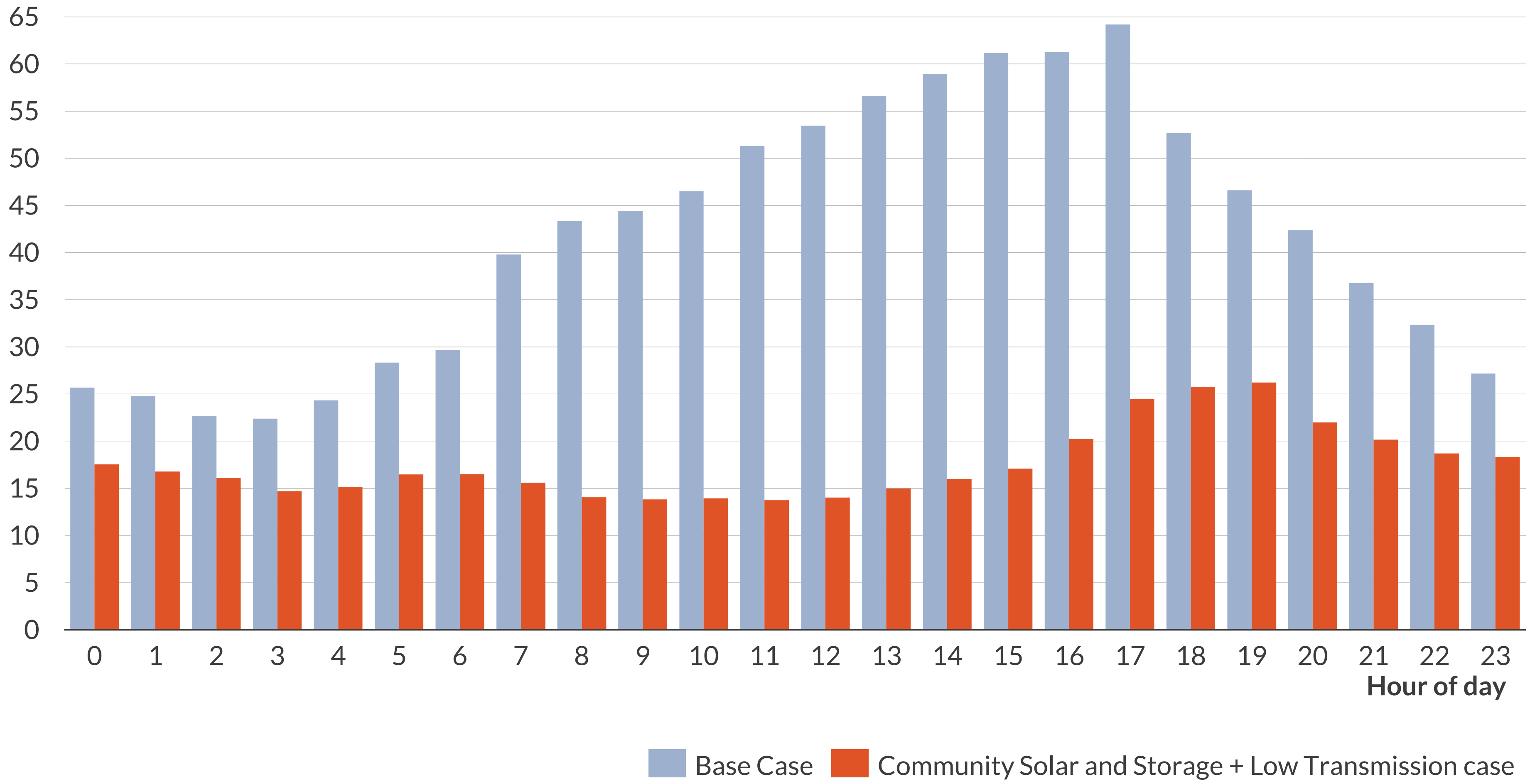
Maximum line flow on the Rio Oso line, September 2033
MW



- In the Base Case, the Rio Oso – West Sacramento line is reconductored, increasing its capacity from 83 MW to 124 MW, in line with the 2023–2024 recommended projects.
- In the High Community Storage and Solar + Low Transmission Case, the line's capacity remains at 83MW
- In the High Community Solar and Storage Case, maximum line flow is lower—particularly during periods of Community Solar and Storage dispatch—highlighting a reduced need for transmission upgrades

Sources: Aurora Energy Research

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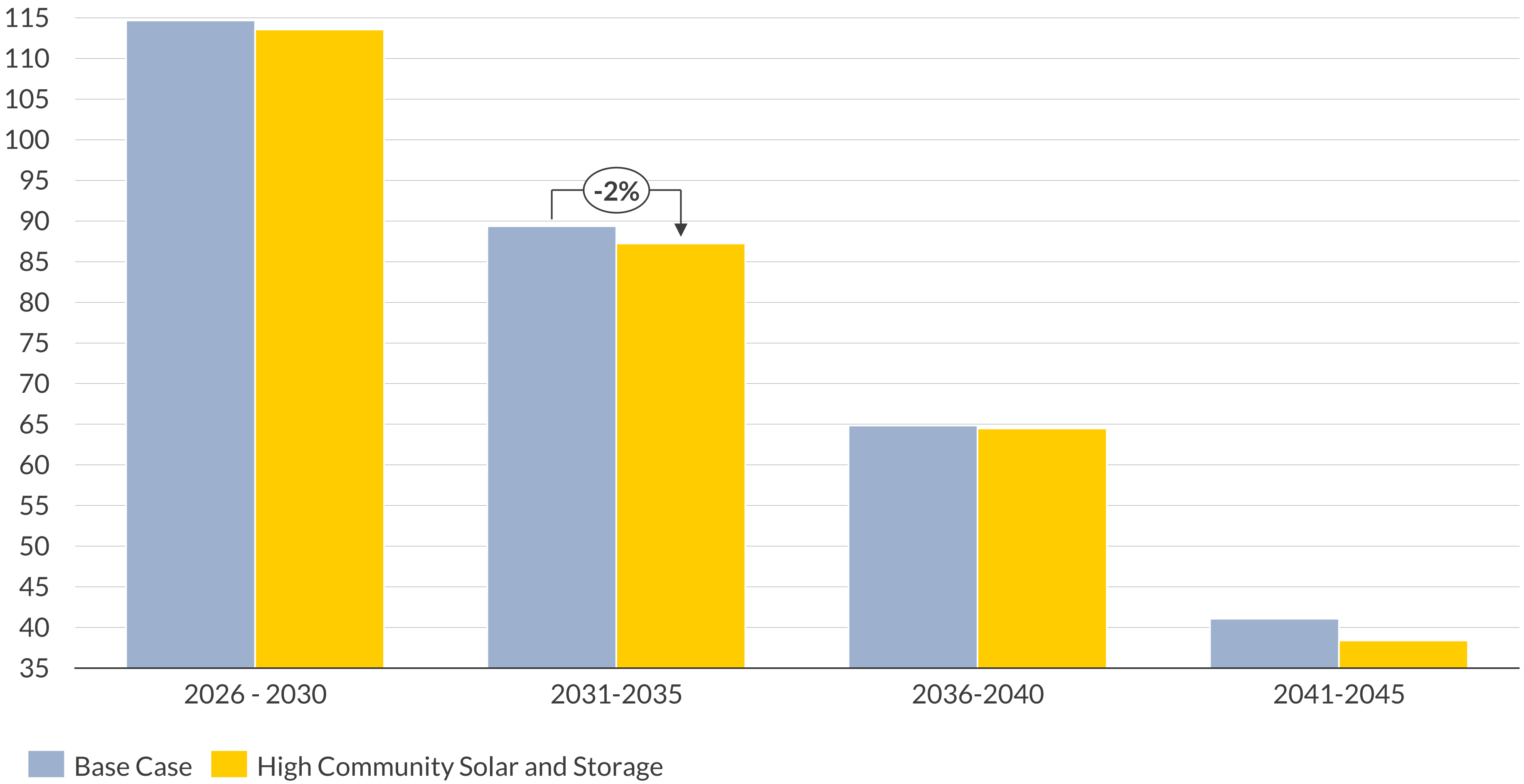
Reduced reliance on natural gas generation in the High CSS Case decreases CO2 emissions 2% compared to Base Case (2025-2045)

Total CAISO CO2 emissions - High Community Solar and Storage vs Base Case
MtCO2



1) ATC wholesale power price is the "Time-Weighted Average" or "Baseload" price.

Sources: Aurora Energy Research

- Community-scale projects generate during peak evening hours, replacing some thermal generation and drives up to 2% total decrease in CO2 emissions in High Community Solar and Storage Case, compared to Base Case over 2025 to 2045
- Reduced reliance on thermal generation in the High Community Solar and Storage Case leads to earlier thermal retirement. In 2045, there is 1.7GW less gas capacity in the High Community Solar and Storage Case, compared to the Base Case

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Aurora's Capacity Expansion and Power Flow model were used to evaluate the impact of community solar and storage

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1 Capacity Expansion and Production Cost Model

Model outputs

- How much new energy capacity will be added to the grid
- Which generators will be retired from the grid
- Hourly regional price forecast

How it works

- Starts with an **initial capacity** mix
- Dispatches this mix to meet energy demand
- Forecasts future capacity mix using:
  - An economic optimization model that selects/retires generators that do/do not meet required investment returns and minimizes system costs
  - A **Planning Reserve Margin** constraint

Input differences across scenarios

	Base Case	High Community Solar and Storage
Initial Capacity	CPUC baseline resources	CPUC baseline + 5.4 GW CSS by 2032
Planning Reserve Margin	CPUC's 2023 PRM	CPUC's 2023 PRM adjusted to account for CSS as load modifiers

2 Power Flow Security-Constrained Economic Dispatch (SCED) Model

Model outputs

- Where new resources will be built
- Which transmission lines will be upgraded
- Locational Marginal Prices at each node, considering supply, demand, and transmission limits

How it works

- Takes capacity mix from the Capacity Expansion Model
- **Places** known baseline and planned resources at their actual locations
- Decides new build locations by comparing nodal costs and benefits
- Includes **approved transmission projects** (CAISO 2023–24 TPP and GIP), then uses an iterative optimization to find the most cost-effective transmission upgrades using budget and cost assumptions

Input differences across scenarios

	Base Case	High Community Solar and Storage	High CSS + Low Transmission
Initial placement	Baseline resources placed at known locations	Baseline resources placed and CSS projects placed in LRAs to match local load	
Approved projects	Approved transmission projects from CAISO 2023-24T TPP and GIP		Cancels 16 projects

The two models solve interactively to produce consistent market-level and network-level forecast scenarios

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Step 1: Model the wholesale and ancillary markets

Step 2: Model the network flows

Feed back loop for new build capacity

- *Locational capacity limits*
- *Basis impacts on asset economics*

Wholesale market assumptions

- Technology, commodity, demand, policy assumptions etc.

1 Capacity Expansion+Production Cost Model

- Simultaneously models wholesale and ancillary service markets
- Hourly granularity
- Iterative modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

Continuous iteration until an equilibrium is reached

Market Level Outputs

- Total load
- Generation mix and economic capacity expansion
- Economic plant retirements
- Short run marginal cost by plant

2 Power Flow Model

- Clears least cost dispatch under transmission constraints
- Calibrated on historic prices and flows

Network Level Outputs

- Asset level generation
- Nodal price outcomes
- Transmission line flows

Input parameters

Network

- WECC 2022 network parameters
- CAISO TPP and GIP transmission line upgrades/development

Generation

- CAISO interconnection queue

Load

- CAISO load demand forecast
- Nodal load participation factors
- Industrial load participation

In-house model | Input | Output

Sources: Aurora Energy Research

The Capacity Expansion model utilizes the CPUC's baseline resource list and economics-based model solve to forecast future capacity

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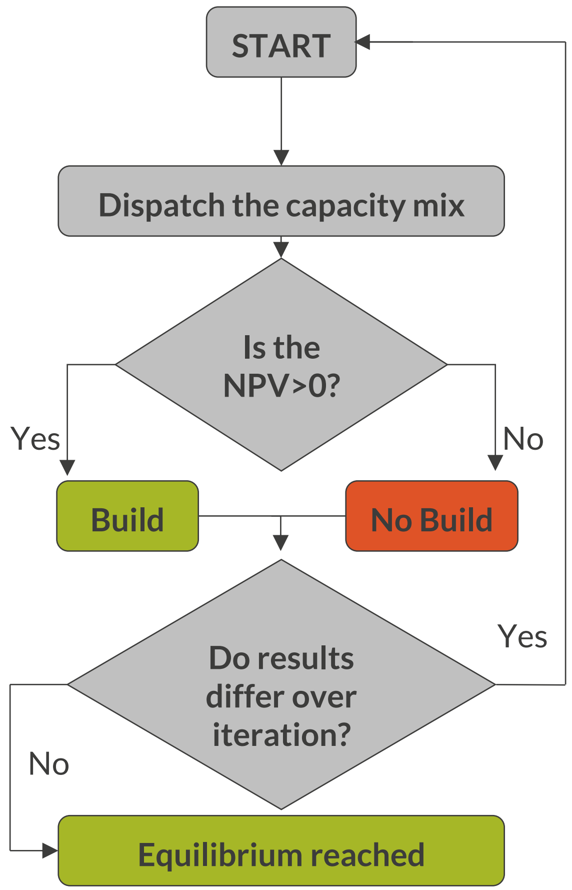
Aurora's Capacity Expansion Model



- The initial capacity mix aligns with CPUC's Baseline Resource List, updated in 11/2024
- In the mid to long-term, Aurora forecasts capacity additions based on an economic model solve and planning reserve margin constraint
- Plants in Aurora's model choose to either build or retire based off a NPV calculation
- Existing plants have the ability to close or continue operating based on unit economics for the plant
- The Aurora methodology **minimizes total system cost over the model lifetime** through a process of algorithmic iteration until lowest system cost is achieved

The Power Flow model determines placement of new build solar, wind, and storage capacity based on economic analysis of nodal GWAs

Moving further into the forecast, the accuracy of placing projects at substations with projects currently queued becomes less certain. Aurora assumes that developers will tend toward economically favorable placements in locations where they have seen historically strong nodal GWAs for new solar and wind projects.

Model solves for dispatch and LMP within **year 1**

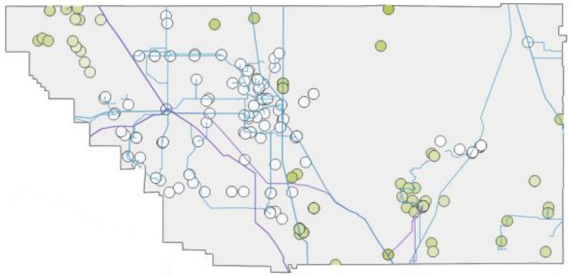
Model determines **placements of RES** for next year

Model solves for dispatch and LMP within **year 2**

1 Initial capture price analysis

Model analyses the pre-curtailed solar and wind capture prices at all nodes from previous years solve specified to be within acceptable building regions

Kern county solar GWA



Key

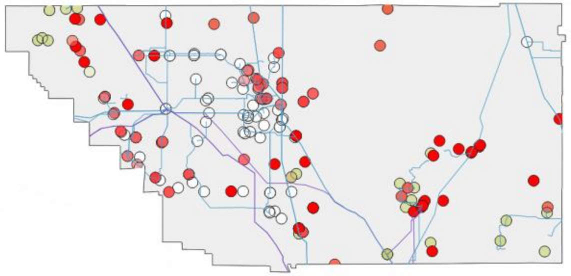
Solar GWA basis
$/MWh

-3 +3

2 Interconnection analysis

Model tests placing the next years solar and wind buildout at nodes with best capture prices. Taking previously solved dispatch it determines whether adding additional solar and wind energy will overload lines. If placement significantly increases congestion or results in curtailment, then that nodes rating is decreased.

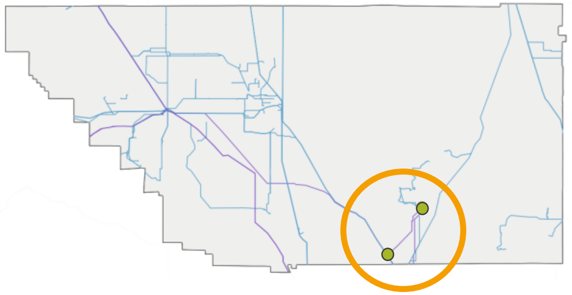
Kern county solar GWA derated for robustness



3 Placement

Based on initial capture price analysis and injection testing, model places newbuild capacity at nodes with best GWA and greatest robustness against additional interconnections.

Kern county selected[1] solar placements



1) Illustrative example.

Sources: Aurora Energy Research, CAISO

The Power Flow model includes all transmission projects approved in CAISO 2023-24 TPP and GIP with scheduled CODs

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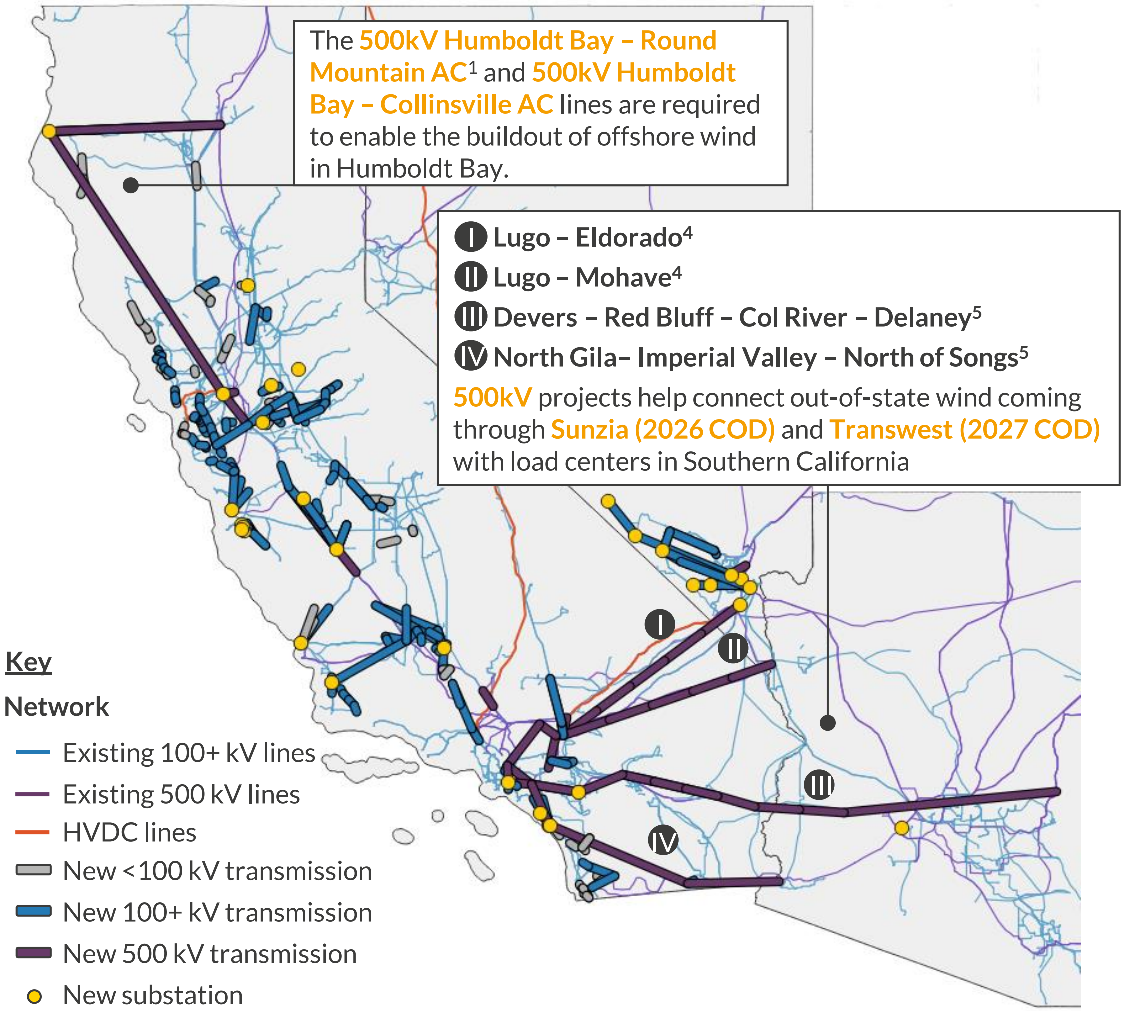
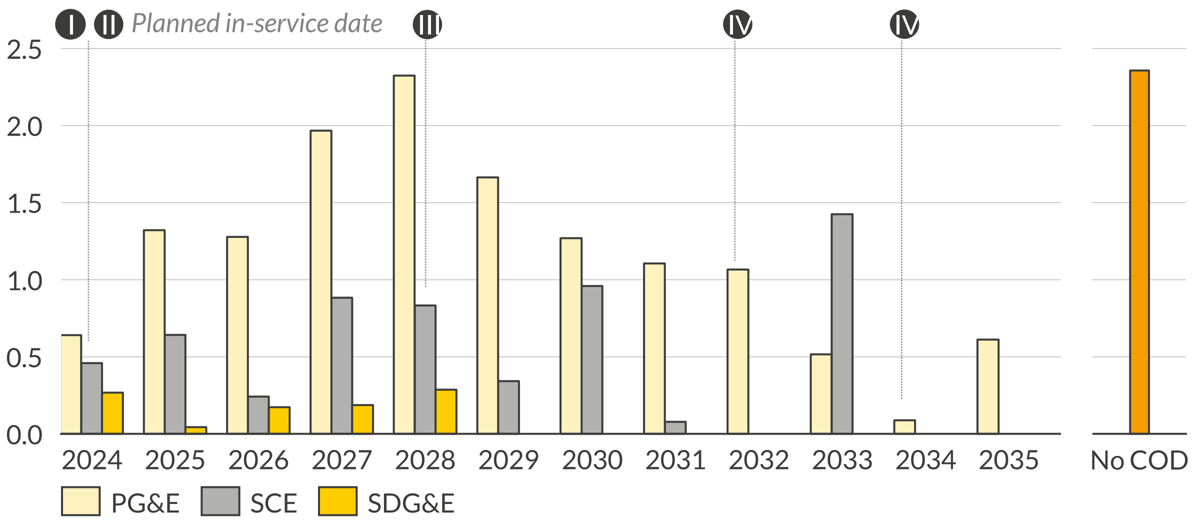
PTO transmission projects 2024-35 incorporated in Aurora modelling



Cumulative cost[2,3] of scheduled transmission projects by PTO

Billions $, real 2023



- CAISO is currently tracking 197 scheduled transmission projects identified in the Transmission Planning Process (TPP) and 89 projects identified in Generation Interconnection Process (GIP)
- TPP projects are designed to keep CAISO inline with reliability, policy, and economic goals
- 2023-24 TPP approved $6.1 Billion to ensure 85 GW new renewables can connect by 2035
- In total, PG&E invests $6.48 billion on transmission by 2035 predominantly covering the NP15 and ZP26 trading hubs, while SCE and SDG&E spends $9.93 billion on SP15 transmission
- Relative to peak load, this represents a $247 million/GW investment in northern vs. a $318 million/GW investment in the southern transmission by 2035
- CPUC's updated General Order 131-D, which streamlines the permitting process for CAISO-approved transmission projects, supports the inclusion of these projects in our CAISO modeling.

1) Assumptions for Humboldt Bay offshore wind transmission build from "Option 1: 500 kV AC line to Fern Road 500 kV substation" in 2021-22 TPP. 2) Reported as cumulative costs of projects within COD year. 3) Costs are taken as reported in July 2023 AB 970 forms for each utility. Costs are averaged between lower and upper bound when only ranges are provided. 4) Series capacitor upgrades anticipated to increase power flow. 5) New transmission and reconductoring projects. Mostly from TPP 22-23.

Sources: Aurora Energy Research, CAISO, PG&E, SCE, SDG&E

Beyond announced projects, the Power Flow model determines line upgrades within regional budgets toward reconductoring lines with high congestion

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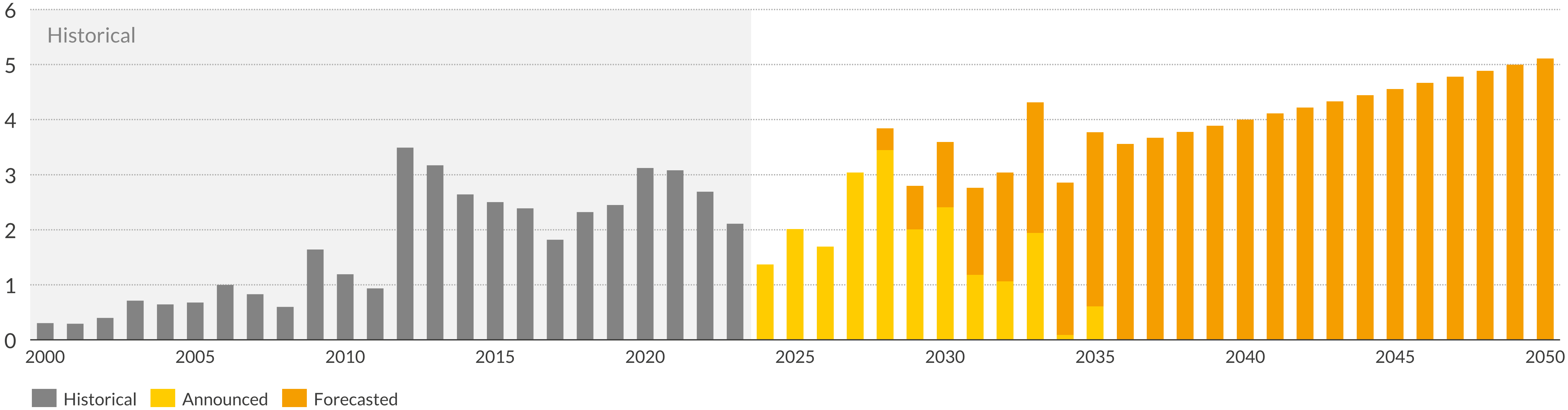
Aurora endogenously models which lines are most economic to reconductor. Aurora assumes region level budgets for transmission investments and average reconductoring project costs, then has model iteratively step through years and determine most economic line upgrades based on SCED power flow congestion analysis.

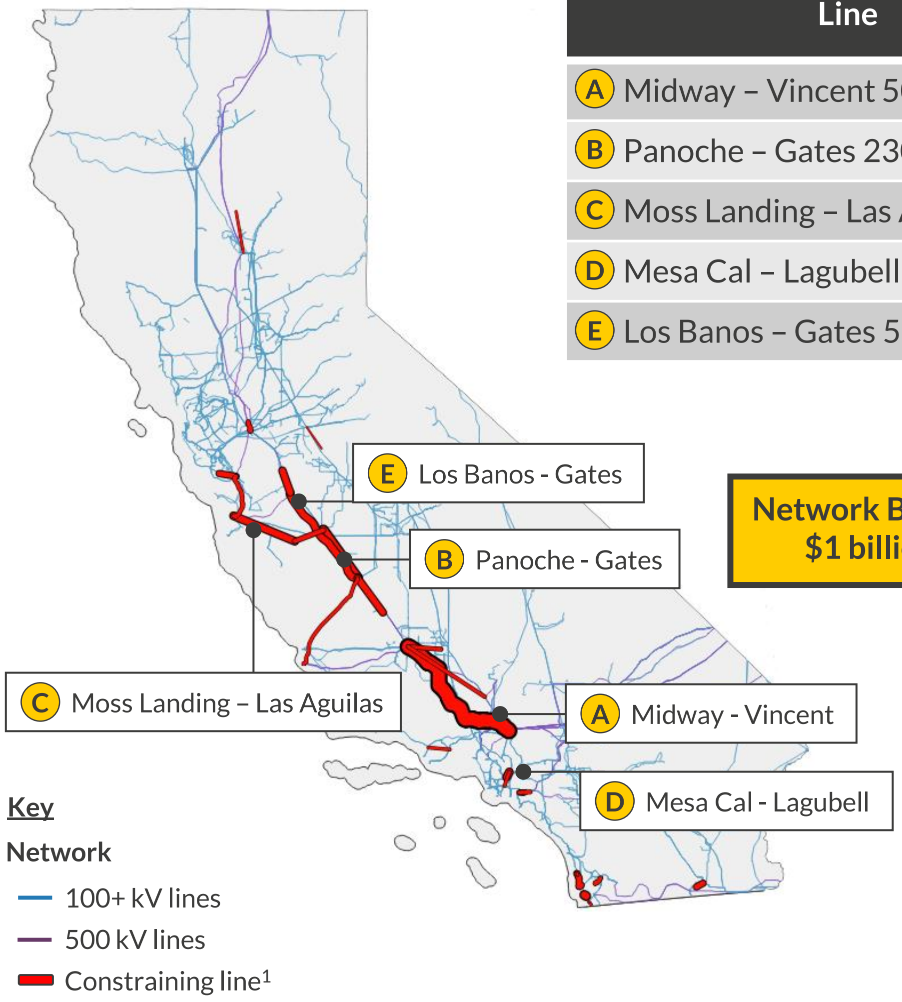
CAISO historical and forecasted transmission spending
billions $



- Accounting for the announced transmission projects having COD up to mid 2030s, the endogenous budget given to CAISO steadily increases starting in 2028
- The modelled budget is calculated as 15% of total forecasted transmission spending budget to represent the proportion of budget historically allocated to reconductoring projects specifically

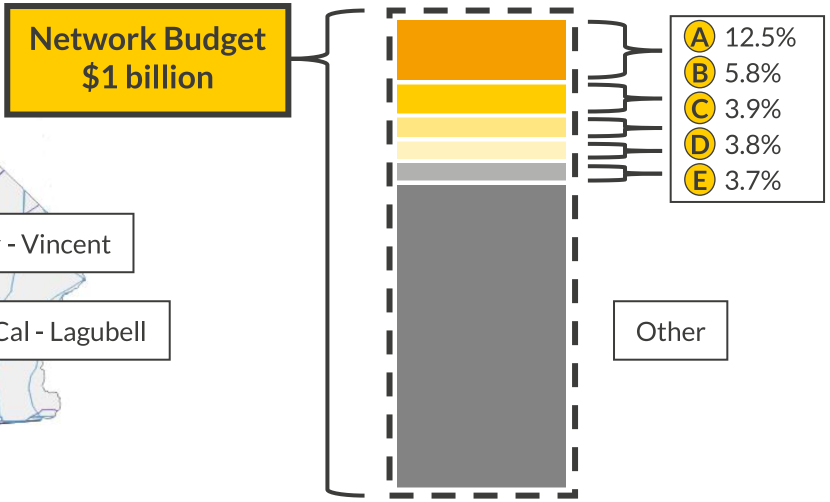
Using forecasted budgets and transmission upgrade cost assumptions, network model iteratively solves for most economic upgrades each year

Constraining CAISO lines, 2022



Line	System Congestion Cost	Cost to Upgrade Line ($/MW-km)
A Midway – Vincent 500kV	12.5 %	196
B Panoche – Gates 230kV	5.8 %	622
C Moss Landing – Las Aguilas 230kV	3.9 %	622
D Mesa Cal – Lagubell 230kV	3.8 %	622
E Los Banos – Gates 500kV	3.7 %	196

Aurora model iterates power flow solve through every year and isolates the transmission lines with greatest shadow price congestion rents. It then allocates a proportional amount of the regional budget toward reconductoring those most constraining lines before moving on to perform power-flow solve of the next year.



10 most constraining lines in each region are assigned amount of yearly budget proportional to shadow price congestion rent

Model uses assigned budget to reconductor those lines as possible for relevant voltage level and line length

Model solves for next year's dispatch and LMP with upgraded line MVA ratings

1) Line sizes scaled by magnitude of congestion rent.

Sources: Aurora Energy Research, CAISO

Power Flow model produces locational marginal prices across nodes, which reflect marginal costs of energy, congestion, and losses

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Components of locational pricing

Locational Marginal Price[1] = Marginal cost of energy + Marginal cost of congestion + Marginal cost of losses

Marginal cost of energy

- System-wide marginal cost of energy required to meet demand in a market interval
- In the Integrated Forward Market, CAISO Full Network Model solves to determine energy and ancillary awards simultaneously for a demand interval taking all bids and transmission constraints into accounts
- FNM solves to minimize overall system cost; MCE is the load weighted average of the marginal cost of generation that is required to serve each node
- Plants with subsidy payments (e.g. tax credits) or expensive ramping costs can bid in at negative prices, which can result in a negative MCE

Marginal cost of congestion

- Represents the difference between the marginal cost of generation that is capable of or required for serving a specific node and the system MCE
- Varies across the network as a result of transmission constraints
- Positive congestion costs represent import constraints and serve as an economic signal to generators to build in that location; energy injected there will receive the higher payment in return for alleviating the constraint
- Negative congestion costs represent export constraints and serve as an economic signal to generators not to build in that location; energy injected there will receive the lower payment as it exacerbates the constraint

Marginal cost of losses

- Transmission losses are factored into the true cost/value of providing energy to a particular location
- MCL is the MCE multiplied by the Marginal Loss Factor[1] (MLF) at a node, where the MLF is a derivative of the actual MW losses that occur when generation is increased at the node and an equivalent amount of demand is increased in the Reference Bus[2]
- Varies across the network
- Serves as an economic signal where generation at a node with positive MCL alleviates congestion and generation at a node with negative MCL exacerbates congestion

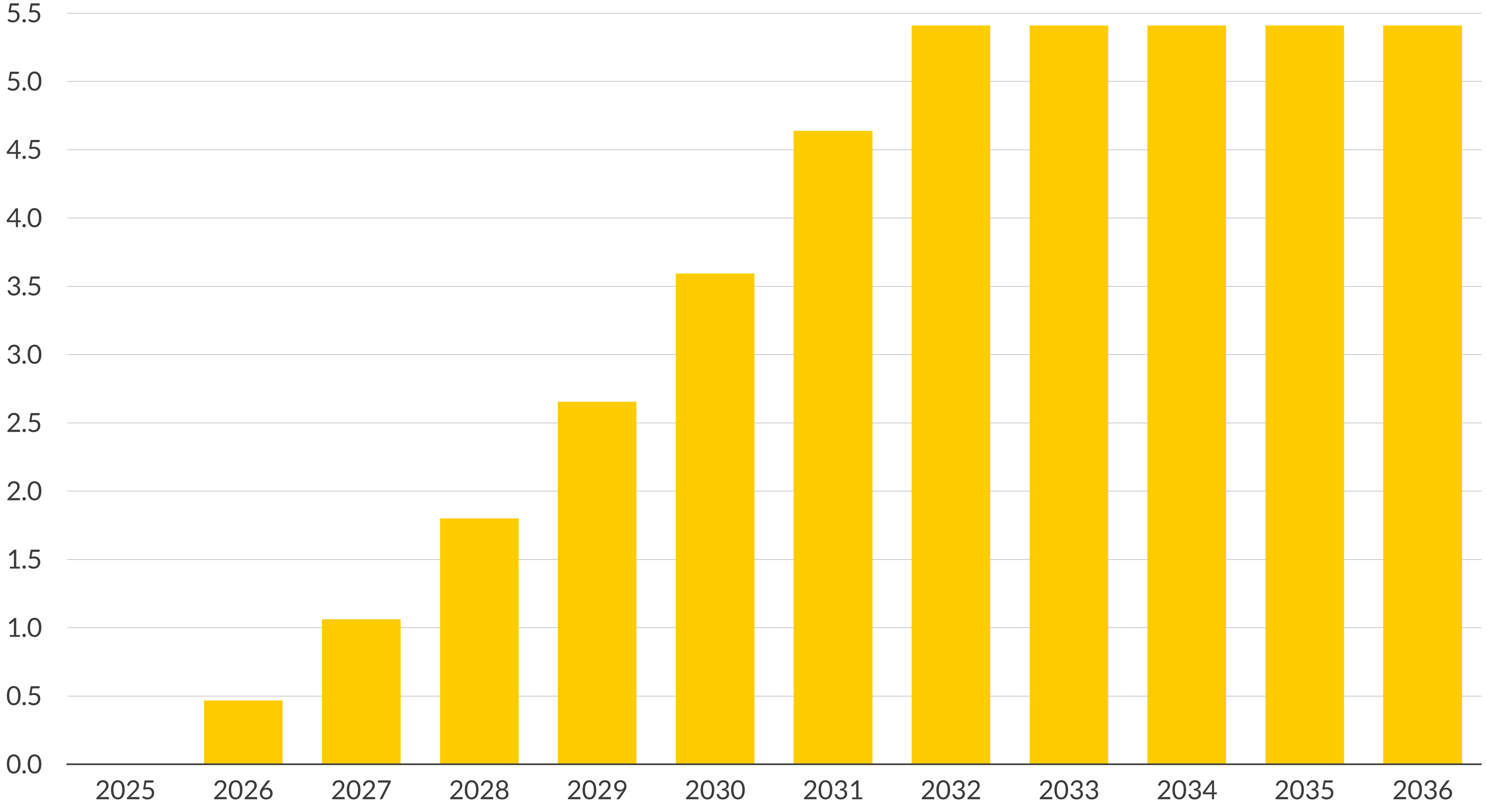
1) The MLF is determined as part of the AC power flow solution during each Trading Hour in the DAM and each 15-minute interval in the RTM. 2) CAISO uses a distributed Reference Bus including all demand PNodes within the system.

Sources: Aurora Energy Research, CAISO

Agenda

In the High Community Solar and Storage (CSS) Scenario, CSS buildout is modelled at a rate of ~1GW/year

Cumulative community-scale project capacity
GW



- Community Solar and Storage buildout is modelled as occurring at a rate of ~1GW/year
- Rate is based on rate of community-scale project adoption in New York after the passage of the Value of Distributed Energy Resources (VDER) program

CSS projects are primarily sited in areas that utilities have forecasted to have relatively high load

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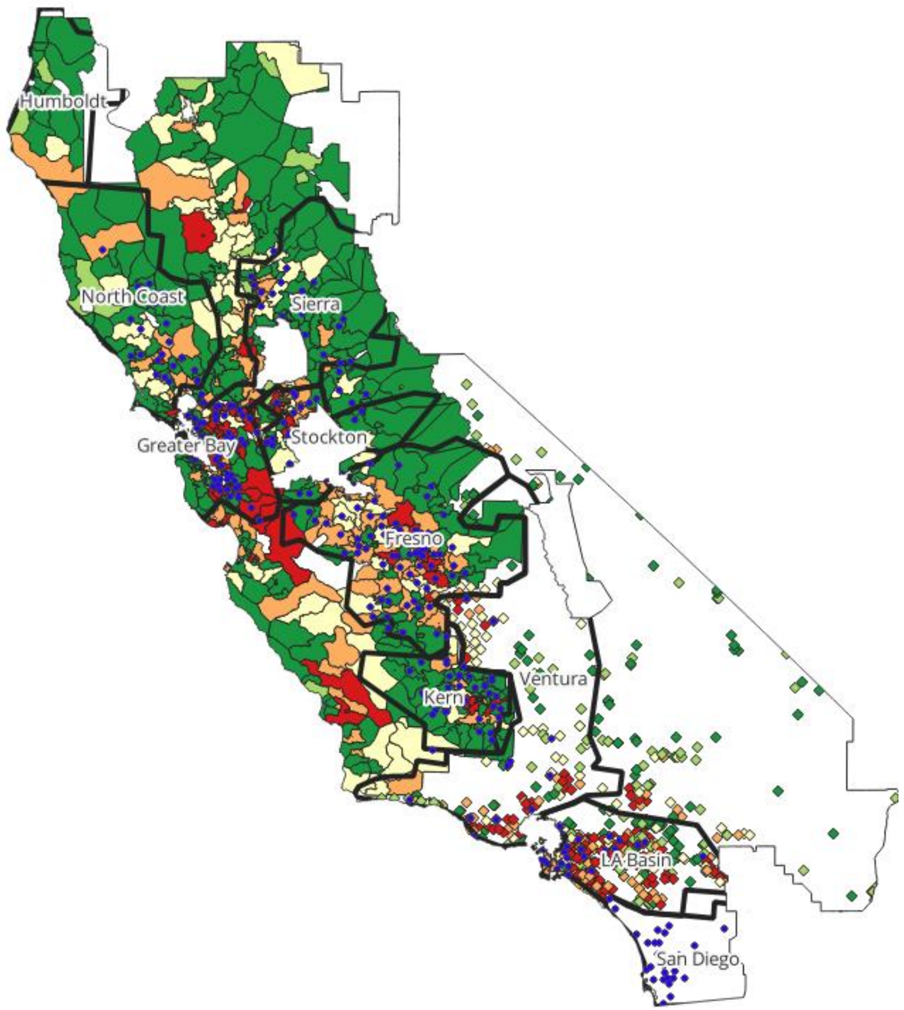
Mapping of community-scale projects in High CSS Case and utility-published substation load forecasts



- SCE and PGE forecasted load data comes from Integration Capacity Analysis (ICA) maps, which help identify areas where the grid can support additional DERs without requiring significant infrastructure upgrades
- Community Solar and Storage projects are cited in LRA's, primarily in areas that utilities have forecasted as having relatively high load

CSS prioritizes dispatch between 5-9pm and the battery component only charges from the solar asset

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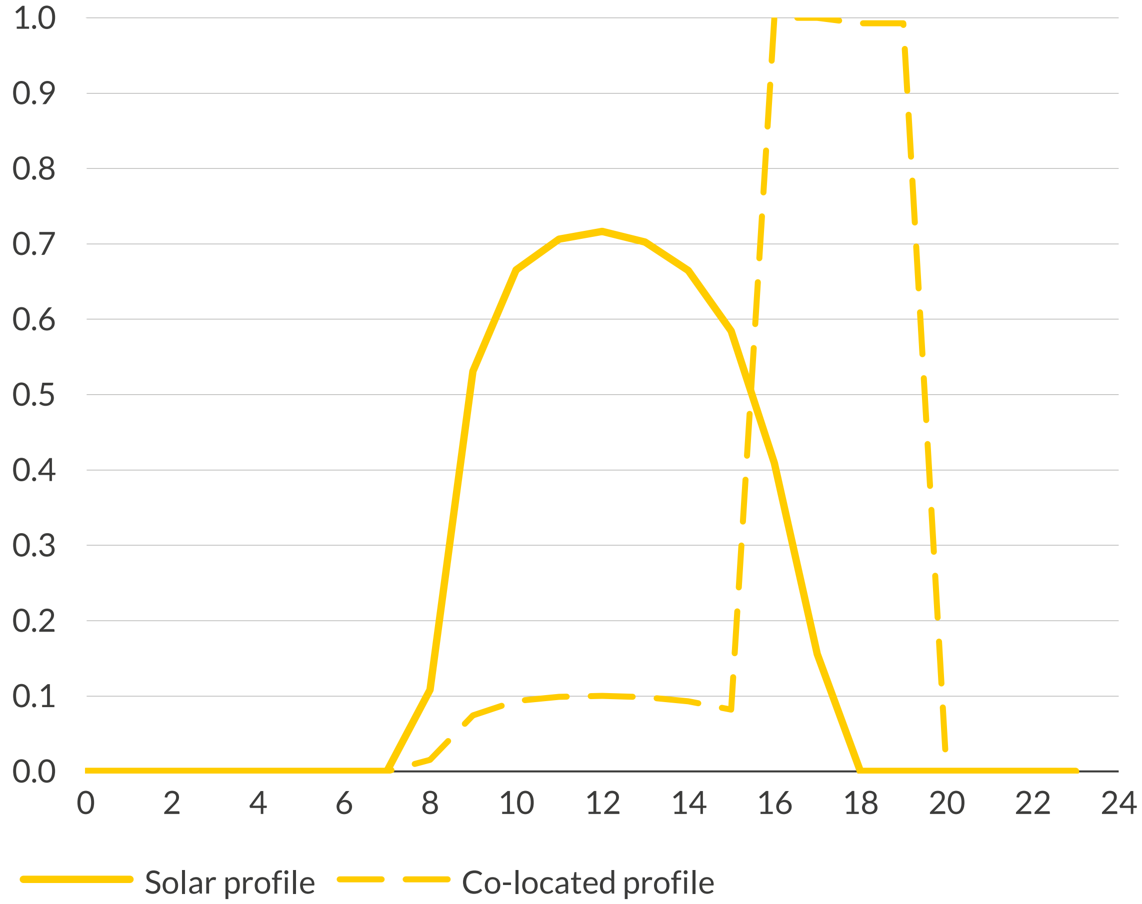
Principles for CSS dispatch

- Battery cannot charge from the grid
- Battery charges less than total solar generation
- The storage configuration is AC coupled, the battery is 4-hour duration, and the ratio is 1.34kW DC PV: 1kW AC PV: 1kW AC BESS
- Battery has 85% round-trip efficiency (IRP assumption)
- Battery storage is modeled with a 90% discharge range (IRP assumption)
- Battery storage has a 5% expected forced outage rate (IRP assumption), which is applied as a uniform haircut to battery dispatch
- Battery dispatches as much as possible during peak evening hours 5-9 pm
- If solar produces during peak evening hours, it will dispatch to grid rather than charge battery
- Solar and battery can simultaneously dispatch to the grid, as long as they don't exceed POI limit (5MW)
- Fixed charging profile - assuming a daily price shape that's fixed

Example intraday day solar vs co-located Community Solar and Storage dispatch profile

MWh/MW



In Scenario 3, High CSS + Low Transmission, $1.1B worth of planned TPP upgrades are not modeled

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Transmission upgrades not modeled in High CSS + Low Transmission case[1]

Project Name	COD	Estimated cost ($M)	Initial capacity (MW)	Capacity after line upgrade (MW)
Vista-Etiwanda 230 kV 1 Line Upgrade	2034	16	797	988
San Bernardino-Vista 230 kV 1 Line Upgrade	2028	19	988	1287
San Bernardino-Etiwanda 230 kV 1 Line Upgrade	2031	74	988	1287
Borden-Storey 230 kV 1 and 2 Line Reconductoring	2029	55	564	1129
Upgrade TL13820 Sycamore-Chicarita 138 kV	2032	70	204	250
Rio Oso - W. Sacramento Reconductoring	2030	127	83	124
Antelope-Whirlwind Line Upgrade	2034	6	2598	3429
Christie-Sobrante 115 kV Line Reconductor	2028	13	91	1228
Herndon-Bullard 115 kV Reconductoring Project	2026	9	125	188
Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	2026	0.5	140	210
North Dublin -Vineyard 230 kV Reconductoring	2035	287	353	706
Pardee-Sylmar 230 kV Line Rating Increase Project	2026	23	1195	1792
Re-conductor 23.63 mi Dos Amigos PP-Panoche #3 230 kV Line with 795 ACSS	2026	51	295	591
Re-conductor 6.25 mi Borden-Gregg #1 230 kV Line with 1113 ACSS	2026	52	295	591
Re-conductor 6.25 mi Borden-Gregg #2 230 kV Line with 1113 ACSS	2026	52	268	537
Imperial Valley – North of Songs 500kV line	2034	300	0	3000

1) Transmission upgrades not modeled are chosen from approved projects in CAISO's transmission planning process, which are high cost and involve line reconductoring or capacity increases on primarily 115-230kV lines.

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