California IOU Grid Capacity to Fully Serve Local Load with Distributed Solar+Storage Systems during Summer Peak/Net Peak Hours

Prepared for the Coalition for Community Solar Access

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Table of Contents

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Executive Summary

The Coalition for Community Solar Access (CCSA) contracted with Kevala, Inc. to estimate the amount and geographic concentration of large investor-owned utility (IOU) distribution-connected load in California that could be served by fully exporting front-of-the-meter distributed solar+storage resources, such as community solar+storage, or storage-only resources during summer peak and net peak demand hours without back-feeding onto the sub-transmission or transmission system.

Specifically, this study estimates the total load and corresponding number of 5-MW systems, each discharging at full capacity for 4 hours, that could be interconnected to the distribution grid and operated from 4 p.m. to 9 p.m. from June through September, with the discharged electricity being fully absorbed by local load behind each substation.

Methodology

For this study, Kevala drew on feeder-level results from the No-Action Unmanaged scenario from the U.S. Department of Energy's *Multi-State Transportation Electrification Impact Study* (TEIS). Hourly load for all feeders at or below 50 kV was aggregated to the feeders' corresponding substations, and the minimum load observed across the summer 4 p.m. to 9 p.m. period was defined to represent the maximum discharge each substation could absorb without needing to backfeed onto the higher voltage transmission or substransmission system. Kevala divided this minimum load/maximum discharge value for each substation by five and rounded down to the nearest whole number to determine the number of 5-MW systems each substation could host. Results were aggregated by IOU for Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) and across all three IOU territories.

Scope and Limitations

This is a technical potential assessment bounded by grid topology. It reflects what the distribution system could accommodate, not what could realistically be permitted, sited, financed, and built; land availability and other development constraints would reduce the market potential considerably. The analysis assumes systems operate under charge and discharge windows set through contractual guardrails to align output with grid need, and that substations redirect surplus generation across feeders on the same substation bus.

Findings

Table ES-1 summarizes Kevala's findings. Across the three large California IOUs, distribution substations could absorb an estimated 17,536 MW of full discharge from distributed front-of-the-meter systems during the summer peak and net peak hours in 2032, 32% of the

California Energy Commission's 2025 Integrated Energy Policy Report Mid-Case Planning Forecast for that year. Based on Kevala's substation load aggregation totals, this translates to approximately 3,112 5-MW systems serving 15,560 MW of local load, with an additional 1,976 MW that could be served with systems sized below 5 MW.

Table ES-1: Minimum load (MW) and total number of front-of-the-meter 5-MW capacity systems (Source: Kevala)

IOU	Total of Substation Non-Coincident Minimum Summer Load from 4-9 p.m. (MW)	Total Number of Front-of-the-Meter 5-MW Systems[1]
PG&E	6,560	1,129
SCE	9,188	1,657
SDG&E	1,788	326
Total	**17,536**	**3,112**

This hosting capacity is geographically dispersed across California, with large pockets of serviceable distribution load concentrated in the Central Valley, across both PG&E and SCE territory, as well as in the Bay Area, Los Angeles basin, and San Diego.

These results indicate that a substantial share of California's distribution-connected load could be met directly using locally sited front-of-the-meter resources throughout the full period of highest resource adequacy procurement costs (4 p.m. to 9 p.m. during the summer months). If these distributed front-of-the-meter systems were treated as load modifiers, they would effectively reduce demand during the hours that drive resource adequacy procurement and transmission investment, with corresponding benefits for all ratepayers.

[1] The total number of megawatts is less than the product of the number of systems multiplied by 5 MW as a result of rounding to the lowest whole number when determining the number of 5-MW systems each substation could accommodate.

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Introduction

The Coalition for Community Solar Access (CCSA) contracted with Kevala, Inc. (Kevala) to estimate the amount and geographic concentration of local load on California's investor-owned utility (IOU) distribution substations that could be served by fully exporting front-of-the-meter distributed solar+storage resources (such as community solar+storage) or storage-only resources.

Specifically, CCSA was interested in the total load and the number of front-of-the-meter solar+storage and storage-only systems (systems),[2] each with total power capacities of 5 MW that could be interconnected to the distribution grid and discharge at full capacity during the highest cost resource adequacy procurement w– the 4 p.m. to 9 p.m. peak/net peak period from June through September – without needing to backflow electricity up to the higher-voltage grid. CCSA was interested in these results for each of the three large California IOUs individually and in aggregate.[3]

This report provides an overview of the methodology and assumptions used as well as the study's results and key findings.

Data Overview

This study used results from the U.S. Department of Energy's (DOE's) *Multi-State Transportation Electrification Impact Study* (TEIS),[4] conducted by Kevala, the National Laboratory of the Rockies (formerly the National Renewable Energy Laboratory), and Lawrence Berkeley National Laboratory in 2024. The TEIS modeled base load, electric vehicle (EV), and solar photovoltaic (PV) profiles that relied on industry-validated tools developed by Kevala's partners at the national laboratories. Kevala's grid infrastructure models were synthesized directly from real distribution data, grounding the study in highly transparent, peer-reviewed data (see Appendix B for an overview of the TEIS).

Kevala used the TEIS results for the *California Load Management Standard Avoided Distribution Grid Upgrade Study* commissioned by GridLab,[5] and that dataset served as the basis for this study.

[2] While solar+storage systems are referenced throughout this document, all of the results apply to storage-only systems with the same power ratings that charge from the grid during non-peak hours.

[3] The three large California IOUs are Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).

[4] The TEIS included the examination of the cost implications of new distribution infrastructure from load growth and transportation electrification in five states, including California (see *Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles*, DOE/EE-2818, U.S. Department of Energy, March 2024).

[5] Kevala, Inc., *California Load Management Standard Avoided Distribution Grid Upgrade Study*, prepared for GridLab, August 2025.

Specifically, Kevala used the feeder loads from the TEIS's No Action-Unmanaged scenario[6] to determine feeder and substation peak load forecasts for 2032 (see Appendix C for more information on the forecasting methodology).

Key Assumptions

This study used the following assumptions:

- System batteries are able to fully charge from a combination of co-located solar and the grid during off-peak hours.
- The minimum load observed during the 4 p.m. to 9 p.m. peak/net peak hours from June through September is assumed to represent the maximum amount of discharge from systems that can meet local load without electricity backflowing to the higher voltage subtransmission or transmission system.
- Substations are configured to redirect backflow onto other feeders rather than up to the higher voltage subtransmission or transmission system (see Appendix A for a complete explanation of Kevala's aggregation and backflow assumptions).
- This analysis is limited to grid topology and provides an estimate of the technical potential of the amount of distribution-connected load that can be supplied by front-of-the-meter systems without back-feeding onto the transmission system. This analysis has not been filtered by other elements of the development process (land availability, etc), which would limit the market potential (i.e., this analysis is based on what the grid can accommodate, not what could actually get built).
- The number of 5-MW systems is calculated by dividing the minimum load at each substation by five and rounding to the lower whole number, which provides a conservative estimate of the number of systems that can be deployed (because in many instances smaller systems could be added to "fill in" the rounded value).

[6] The No Action-Unmanaged scenario from the TEIS did not account for future additional legislation to incentivize electric vehicle supply equipment adoptions and did not include any managed charging programs. It was one of several scenarios included in the TEIS.

Methodology

Kevala used a multi-step approach for its analysis, which is outlined in the following sections.

1. Determine Minimum Load During Discharging Period

Kevala filtered the TEIS dataset for the No Action-Unmanaged scenario to feeders at or below 50 kV in the IOU service territories. Next, Kevala aggregated the total hourly megawatt (MW) load for each of these feeders from 4 p.m. to 9 p.m. during the summer months (June through September) for 2032 to each IOU substation. Kevala then identified the minimum load at each substation across the full summer month peak/net peak period.

2. Determine Equivalent Storage System Hosting Capacity

For each substation, the minimum summer peak/net load was divided by five and rounded to the lowest whole number to determine the number of 5-MW systems that could be fully discharged to serve local load behind each substation without backflowing discharged energy onto the higher-voltage subtransmission or transmission system. For example, if a substation's minimum load during the 4 p.m. to 9 p.m. window was 12.8 MW, it was determined to support two 5-MW systems operating simultaneously. If the minimum load was 4.9 MW, the substation would not support a 5-MW system.

3. Generate and Aggregate Results

The final results were limited to substations owned by California's three large IOUs: PG&E, SCE, and SDG&E. Each substation was assigned to its corresponding IOU based on the utility operator recorded in the TEIS dataset. For each substation, Kevala quantified:

- Minimum summer evening load (MW)
- Equivalent number of 5-MW systems that could be accommodated

The number of systems were then aggregated by IOU.

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Results and Key Findings

Table 1 shows the total substation non-coincident[7] minimum summer load during the 4 p.m. to 9 p.m. period and the total number of 5-MW co-located front-of-the-meter solar+storage or storage-only systems that could be accommodated based on the minimum load at each substation for each IOU. The table also shows the relationship of these results to the 2025 California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) Mid-Case Planning Forecast for 2032.[8]

Table 1: Minimum load (MW) and total number of front-of-the-meter 5-MW capacity systems (Source: Kevala)

IOU	Total of Substation Non-Coincident Minimum Summer Load from 4-9 p.m. (MW)	2025 CEC IEPR Mid-Case Planning Forecast for 2032 (MW)	Percentage of 2025 CEC IEPR Mid-Case Planning Forecast for 2032	Total Number of Front-of-the-Meter 5-MW Systems[9]
PG&E	6,560	25,000	26%	1,129
SCE	9,188	25,200	37%	1,657
SDG&E	1,788	4,600	39%	326
Total	**17,536**	**54,800**	**32%**	**3,112**

The analysis indicates substantial local load could be met by front-of-the-meter distributed solar+storage systems across the California IOU substations:

- SCE exhibited the largest amount of estimated local load, with a total non-coincident minimum summer peak/net peak load of 9,188 MW, corresponding to approximately 1,657 5-MW systems.
- PG&E followed with 6,560 MW of non-coincident minimum summer peak/net peak load, which would support an estimated 1,129 5-MW systems.
- SDG&E contributed an additional 1,788 MW of minimum peak/net peak load, equivalent to approximately 326 5-MW systems.

[7] As used in this report, "non-coincident" refers to the aggregated minimum load at each substation during the summer 4 p.m. to 9 p.m. period being non-coincident across substations. The minimum load is coincident across the individual feeder loads at each substation but non-coincident across all substations.
[8] California Energy Demand (CED) 2025 Forecast, as presented in the CEC, "2025 IEPR Forecast- Updated Results," DAWG Meeting, January 5, 2026.
[9] The total number of megawatts is less than the product of the number of systems multiplied by 5 MW as a result of rounding to the lowest whole number when determining the number of 5-MW systems each substation could accommodate.

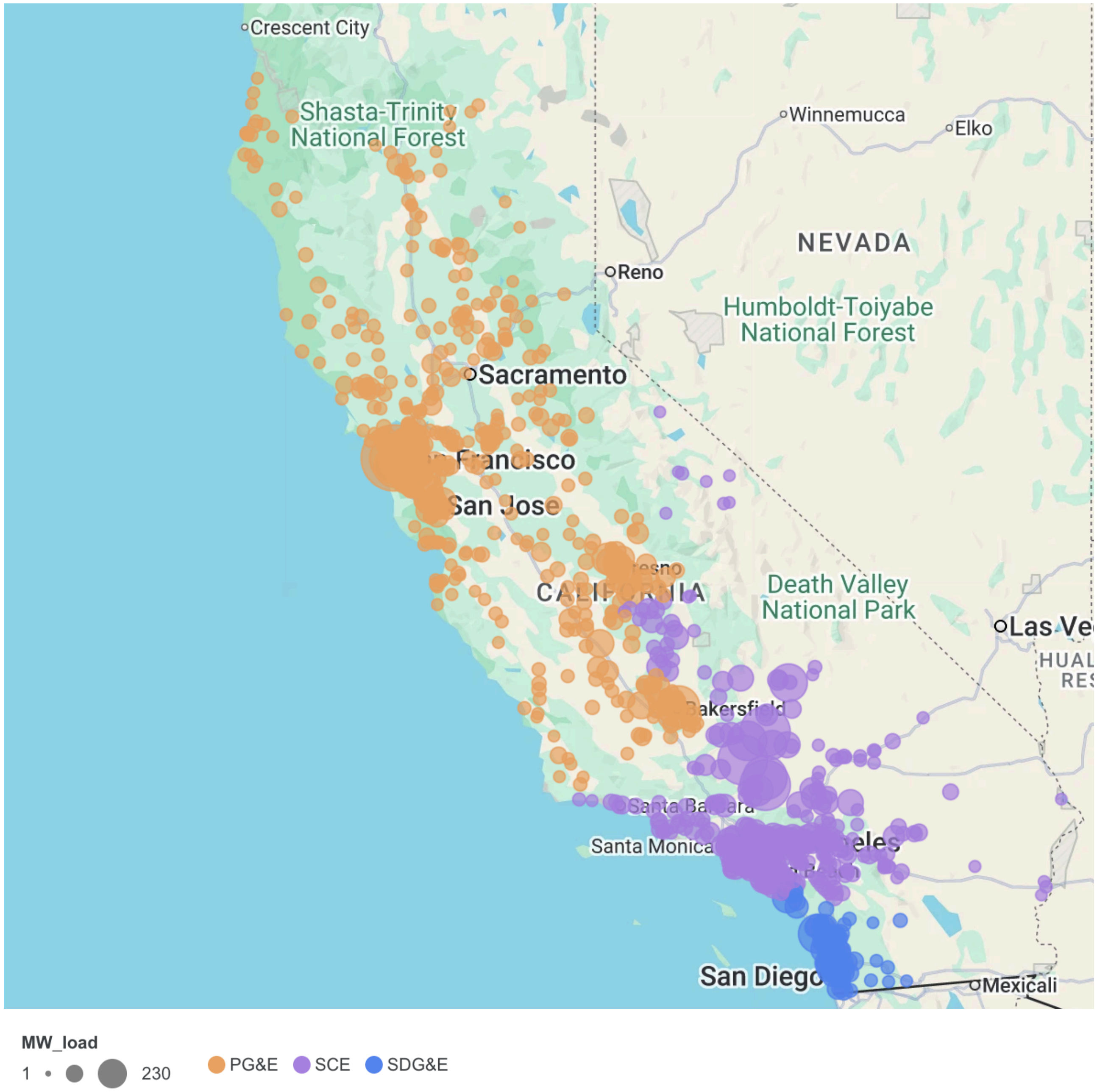
Collectively, the three IOUs could serve approximately 17,536 MW of local load, which could accommodate 3,112 5-MW front-of-the-meter solar+storage or storage only systems.[10] It is important to note that the total number of megawatts for the 5-MW systems is less than the product of the number of systems multiplied by 5 MW as a result of rounding to the lowest whole number when determining the number of 5-MW systems each substation could accommodate. This means that 15,560 MW of local load could be fully met with 5-MW systems during the summer net peak demand period, and that an additional 1,976 MW could be served with systems sized below 5 MW.

These results indicate that a substantial share of California's distribution-connected load could be met directly using locally sited front-of-the-meter resources throughout the full period of highest resource adequacy procurement costs (4 p.m. to 9 p.m. during the summer months). If these distributed front-of-the-meter systems were treated as load modifiers, they would effectively reduce demand during the hours that drive resource adequacy procurement and transmission investment, with corresponding benefits for all ratepayers.

Figure 1 provides a heat map of substations across the three large California IOUs. Each substation was plotted using its latitude and longitude coordinates. The color identifies the corresponding IOU and whether the substation could accommodate a 5-MW system; the size of the bubble is based on the substation's load. As the figure shows, the distribution substations that could support these front-of-the-meter systems is geographically dispersed across California, with large pockets of serviceable distribution load concentrated in the Central Valley across both PG&E and SCE territory, as well as in the Bay Area, Los Angeles basin, and San Diego. Appendix D provides a version of the heat map that identifies both substations that do and do not have sufficient minimum load from 4 p.m. to 9 p.m. in the summer months to accommodate the full discharge from at least one 5-MW system.

[10] Preliminary feeder-level analysis that did not account for redirected backflow across feeders on the same substation produced results of 9 GW-15 GW of peak/net peak load that could be served by these systems for a range of different discharge assumptions. These preliminary results were provided by CCSA in a CEC workshop on demand flexibility and opportunities/challenges for front-of-the-meter distributed energy resources in California held on July 15, 2026.

Figure 1: Heat map of substations by IOU and substation load (Source: Kevala)



Appendix A. Substation Aggregation and Backflow

Distribution substations typically serve multiple radial feeders connected to a common medium-voltage bus on the transformer's secondary side. Because these feeders are electrically tied at the bus, power flows along all available network paths based on voltage differentials and relative impedance rather than remaining confined to a single circuit. Consequently, when distributed energy resource (DER) generation on a feeder exceeds its local load, the resulting voltage rise drives excess power back to the bus. There, power follows toward and along the paths of lowest impedance, naturally supplying local demand on adjacent feeders before any remaining surplus flows upstream through the transformer to the higher-voltage system. Net export to the upstream transmission network occurs only when aggregate generation across all bus-connected feeders exceeds their combined load and losses.[11] Accordingly, this study evaluated conditions at substations and downstream feeders under the assumption that systems are contractually required to charge and discharge during time windows set to prevent net power export upstream to the primary side of the substation and onto the transmission or subtransmission grid.

Importantly, reverse flow at an individual feeder head is distinct from substation-level net export. Feeder-level reverse flow occurs whenever a circuit's generation (including discharge from storage systems) exceeds its own load, which frequently happens while the substation as a whole remains a net importer. Under the assumption of no net upstream export, thermal overloading at the substation transformer is avoided. However, heavy reverse current on an individual circuit can still approach or exceed the thermal capacity of conductors. Feeder reverse flow and DER fault contributions also introduce complex protection and voltage-regulation challenges. Legacy equipment, including reclosers, voltage regulators, and load tap changers, can require replacement or reconfiguration. Additionally, protection schemes may require upgrades for short-circuit and ground fault overvoltage mitigation.

Because California has been experiencing and interconnecting high levels of distributed generation for over two decades, some portions of the state's distribution grid have already been upgraded with these protections. When this is not the case, and feeder or substation upgrades are required to accommodate feeder-level reverse flow across a substation's feeder head bus, these upgrades are identified through the Wholesale Distribution Access Tariff/Wholesale Distribution Tariff or Rule 21 interconnection studies and funded directly by project developers under current IOU tariffs.

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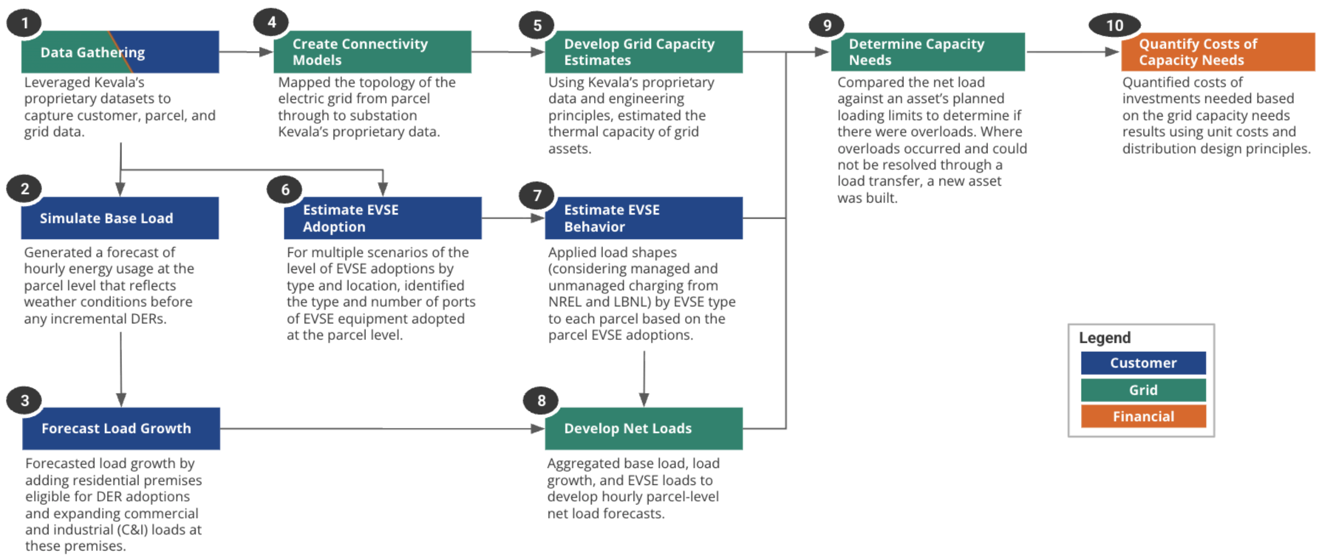
[11] In substations employing a split-bus architecture, feeders on opposite sides of an open bus tie are not electrically connected under normal operating conditions, and the load available to absorb excess generation is limited to circuits on the same bus section. Site-specific conditions of this kind are identified and addressed through the interconnection study process.

Appendix B. TEIS Summary

This study used results from the *Multi-State Transportation Electrification Impact Study* (TEIS)[12] conducted by the National Laboratory of the Rockies (NLR),[13] Lawrence Berkeley National Laboratory (Berkeley Lab), Kevala, and the U.S. Department of Energy (DOE) in 2024. Kevala calibrated the results of the TEIS to inputs specific to the *California Load Management Standard Avoided Distribution Grid Upgrade Study* commissioned by GridLab[14] as well as this study.

Figure B-1 shows an overview of the TEIS methodology, which also included a capacity needs and cost analysis (steps 9 and 10) that was not applicable to this study.

Figure B-1: Overview of the TEIS methodology (Source: Kevala)



The TEIS used Kevala's proprietary data to generate a grid connectivity model for five states:

- California
- Illinois
- Pennsylvania
- New York
- Oklahoma

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[12] NLR, Berkeley Lab, Kevala, Inc., and U.S. Department of Energy, *Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles*, DOE/EE-2818, U.S. Department of Energy, March 2024.
[13] Formerly the National Renewable Energy Laboratory (NREL).
[14] Kevala, Inc., *California Load Management Standard Avoided Distribution Grid Upgrade Study*, prepared for GridLab, August 2025.

For each state, Kevala developed a base load forecast, at the parcel level, using NLR's ResStock[15] and ComStock[16] granular modeling of the country's residential and commercial building stock. Kevala then implemented its electric vehicle (EV) adoption methodology to assign EV supply equipment (EVSE) port installations to individual parcels. A corresponding EVSE load shape for that particular EVSE port type was also assigned to the parcel to reflect the load impacts of the adoption.

For those parcels eligible and selected for EVSE adoption, a load shape of the EVSE port type was applied to the parcel's forecasted load to reflect its adoption of the EVSE and the impact on load. These parcel loads were then aggregated up from parcel to service transformer to feeder to substation.

Kevala evaluated aggregated loads to identify loads exceeding the design capacity of the connectivity model. When excess load was identified, a new asset would be constructed with a state-specific cost based on a set of previous assumptions.

Study Scenarios

For the initial study, four scenarios were run in each of the five states:

- **No Action-Unmanaged:** This scenario did not account for future additional legislation to incentivize EVSE adoptions and did not include any managed charging programs.
- **No Action-Managed:** This scenario did not account for future additional legislation to incentivize EVSE adoptions, but did include managed charging.
- **Action-Unmanaged:** This scenario accounted for future legislation impacts on EVSE adoptions, but did not include managed charging.
- **Action-Managed:** This scenario accounted for future legislation impacts on EVSE adoptions and managed charging.

Comparison to Other California Studies

The TEIS forecast was calibrated to the U.S. Energy Information Administration's (EIA's) 2021 forecast for California. After removing data center load,[17] the EIA's load forecast for 2032 was more than 10% lower than the 2025 (adopted 1/2026) California Energy Commission (CEC)

[15] NLR, ResStock: https://resstock.nlr.gov/
[16] NLR, ComStock: https://comstock.nlr.gov/
[17] Data center load is expected to largely be interconnected at the transmission and subtransmission level and is therefore not expected to add a significant amount of load to the <50 kV distribution feeders and associated substations included in this study's analysis.

Integrated Energy Policy Report forecast (approximately 280 TWh for EIA vs. approximately 325 TWh for CEC's Mid-Case),[18] largely because building electrification was not included in the EIA forecast.

Additionally, the TEIS dataset addressed feedback from the California IOUs regarding some of the EV load shapes and charging windows used in the Electrification Impacts Study (EIS) that Kevala conducted for the California Public Utilities Commission (CPUC)[19] by using NLR- and Berkeley Lab-developed EV load shapes and charging windows.

[18] California Energy Demand (CED) 2025 Forecast, as presented in the CEC, "2025 IEPR Forecast- Updated Results," DAWG Meeting, January 5, 2026.

[19] Kevala, Inc., *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates*, prepared for the California Public Utilities Commission, Energy Division for Proceeding R.21-06-017 (Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future), May 9, 2023

Appendix C. Forecast Methodology Details

Kevala used the non-coincident peak load for each existing asset (excluding the option to transfer load) and the estimated rated capacities of these existing assets from the *Multi-State Transportation Electrification Impact Study* (TEIS).[20] Kevala calibrated the feeder loads from the TEIS's No Action-Unmanaged scenario and then calculated feeder and substation forecasts for 2027 and 2032. These forecasts served as the Base Case for the *California Load Management Standard Avoided Distribution Grid Upgrade Study* commissioned by GridLab[21] and the forecasts for this study, which were aggregated up to the substation level.

Feeder Load Forecasts

Starting with a 2023 base load forecast, the TEIS developed load forecasts for all California feeders for 2027 and 2032. For this study, feeder loads were estimated using the TEIS's No Action-Unmanaged scenario for 2032.

Demand Calibration

Due to the use of simulated loads in the TEIS, multiple feeders experienced significant loads in the forecast years that were well over the maximum capacity of the feeder. These high load forecasts resulted in large capacity additions in a single year. For this study, Kevala reviewed the 2027 forecast and amended it for any feeders with more than 30 MW of load. This calibration was done to account for the TEIS's mapping from a parcel level to a feeder, not considering that a parcel's load may not be on a distribution asset. The 30 MW threshold was used because loads greater than 30 MW would normally be considered on a subtransmission or transmission asset. This calibration lowered the total loads on the feeders in 2027.

For this calibration, Kevala first capped the peak demand at 30 MW, then took the ratio of the capped demand divided by the original peak demand (i.e., a calibration factor), and applied the ratio to all the loads for 2027. The last step was to add the distributed energy resource (DER) load for each hour to the capped demand to get the capped net load for 2027. For 2032, Kevala added the difference in demand from 2027 to 2032, multiplied by the calibration factor, and added 2032 DERs. Finally, Kevala aggregated the calibrated TEIS feeder hourly loads to generate hourly substation loads. Kevala also used the TEIS estimates of substation capacity.

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[20] NLR, Berkeley Lab, Kevala, Inc., and U.S. Department of Energy, *Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles*, DOE/EE-2818, U.S. Department of Energy, March 2024.

[21] Kevala, Inc., *California Load Management Standard Avoided Distribution Grid Upgrade Study*, prepared for GridLab, August 2025.

Appendix D. Heat Map Depicting All Substations

The following heat map identifies the California IOU substations, both those that do and do not have sufficient minimum load from 4 p.m. to 9 p.m. in the summer months to accommodate the full discharge from a 5-MW system. Darker colors are associated with substations that have sufficient minimum load.

Figure D-1: Heat map of substations with and without sufficient minimum load (Source: Kevala)