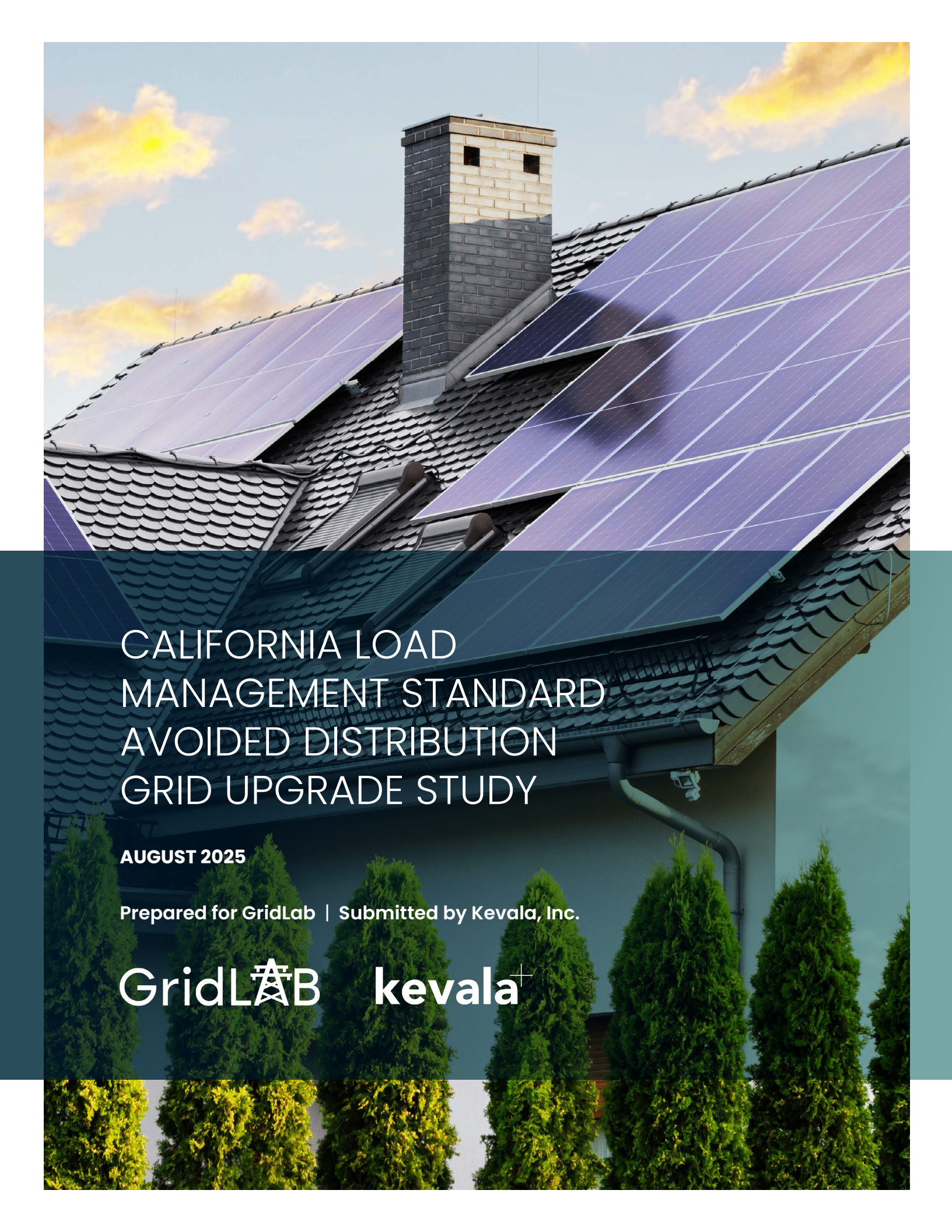




CALIFORNIA LOAD MANAGEMENT STANDARD AVOIDED DISTRIBUTION GRID UPGRADE STUDY

AUGUST 2025

Prepared for GridLab | Submitted by Kevala, Inc.

GridLAB **kevala**⁺

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■ Acronyms

BTM	Behind-the-Meter
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DER	Distributed energy resource
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EIS	Electrification Impacts Study
ELR	Economic load reach
EV	Electric vehicle
EVSE	Electric vehicle supply equipment
GW	Gigawatt
IEPR	Integrated Energy Policy Report
kV	Kilovolt
kVa	Kilovolt-ampere

kW	Kilowatt
kWh	Kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LMS	Load Management Standard
MCOS	Marginal cost of service
MW	Megawatt
NREL	National Renewable Energy Laboratory
NWA	Non-wires alternatives
OH	Overhead
ROE	Return on equity
RRQ	Revenue requirement
TEIS	Transportation Electrification Impact Study
UG	Underground
U.S.	United States



■ Executive Summary

GridLab contracted with Kevala, Inc. (Kevala) to develop an estimate of the potential avoided cost benefits of achieving California's Load Management Standard (LMS) goal to double the amount of load shift from 3.5 GW to 7 GW by 2030. The study analyzed different peak load reduction scenarios leveraging previous work conducted for the U.S. Department of Energy's *Multi-State Transportation Electrification Impact Study*.

For this study, Kevala estimated total avoided distribution system upgrade costs and the marginal cost of service (MCOS) resulting from achieving the LMS goal under a Base Case and three scenarios:

- **Pro Rata:** Reducing load by 3.5 GW across all assets in the state proportionally to their forecasted non-coincident peak loads.
- **High to Low:** Reducing the load on the most highly overloaded assets, removing its need for an upgrade, and then working down the successive overloaded assets from highest to lowest until the full 3.5 GW goal was exhausted.
- **Low to High:** Reducing the load on the least overloaded assets to the point that it no longer required an upgrade, then working up the successively overloaded assets from lowest to highest until the full 3.5 GW goal was exhausted.

Depending on the scenario, **LMS allocation reduced estimated distribution capital costs from \$3.2 to \$11.9 billion**, which equates to reductions of \$3.7 to \$13.7 billion in total present value costs to customers.

The distribution of load savings across feeders, substation transformers, and substations reduces the number of asset overloads for all LMS scenarios as compared to the Base Case, and there are **notable capital cost savings from the LMS peak reductions regardless of the strategies used to achieve the goal and the urbanization category of the load reductions**. The Low to High scenario in which the LMS peak load reduction was allocated to assets starting with the lowest overloads and moving up to highest yielded the highest reduction in costs. The reason for this is two-fold:

- More feeders were mitigated.
- More urban feeders were addressed (on a percentage basis) relative to other urbanization categories, which provided greater cost savings because urban assets have higher unit upgrade costs per megawatt of capacity.

This outcome suggests that load reduction efforts may be beneficial if they target a range of assets that are forecasted to be not extremely overloaded and for which load allocation is costly versus just upgrading those overloaded assets—especially if the targeted range of assets focuses on load reductions on urban versus suburban or rural assets.

Benefits quantified by the MCOS approach did not vary as greatly as with the avoided cost approach. However, MCOS analysis and results offer important insights into the relationship between capacity and capital costs, such as how the proportion of urban versus suburban/rural assets that require upgrades after allocating the LMS targeted peak reductions will affect the remaining cost of service.

A direct avoided cost method based on individual asset cost savings resulting in more significant differences in benefits than an MCOS analysis emphasizes the need for both types of analyses to obtain a complete picture of benefits from efforts to reduce peak loads in general and the LMS in particular. Additionally, the difference in costs based on urbanization category versus not considering an asset's physical location is important because, though MCOS vary slightly in this comparison, the location is important to optimize the value of LMS peak reductions.

■ Introduction

GridLab engaged Kevala, Inc. (Kevala) to provide an estimate of the potential avoided cost benefits of achieving California's Load Management Standard (LMS). In 2022, the California Energy Commission (CEC) adopted new load management standards¹ to promote demand flexibility and help integrate renewable energy resources. These standards require large electricity providers to offer retail rates that change at least hourly, reflecting real-time grid costs and greenhouse gas emissions. This incentivizes customers to shift their electricity usage to times when power is cheaper and cleaner, such as when solar energy is abundant.

Aligned with previous work completed for GridLab,² this study focuses on estimating the benefits of the LMS by leveraging the U.S. Department of Energy's (DOE's) *Multi-State Transportation Electrification Impact Study* (TEIS),³ conducted by Kevala, National Renewable Energy Laboratory (NREL), and Lawrence Berkeley National Laboratory (LBNL) in early 2024. The TEIS included examining the cost implications of new distribution infrastructure from load growth and transportation electrification in California.

Study Overview

Kevala estimated the benefits of LMS using two different analytic approaches:

- **Avoided cost analysis:** Estimated total avoided distribution costs when achieving the CEC LMS goal to double the amount of load shift from 3.5 GW to 7 GW by 2030 using different peak load reduction strategies. This analysis focused on comparing the costs to mitigate additional grid capacity needs from load growth under a Base Case scenario and three LMS scenarios.
- **Marginal cost of service (MCOS) analysis:** Developed locational marginal costs based on the incremental capital needs and capacity additions under the same four scenarios (Base Case and three LMS scenarios).

Both approaches used the peak load forecasts from the TEIS's No Action-Unmanaged scenario (the Base Case for this study), which aligns with electric vehicle (EV) and electric vehicle supply

1 The CEC developed the Load Management Standard and the 3.5 GW goal to comply with the requirements in Senate Bill 846 (Dodd, 2022): https://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB846

2 The Brattle Group, *California's Virtual Power Plant Potential: How Five Consumer Technologies Could Improve the State's Energy Affordability*, prepared for GridLab, April 2024.

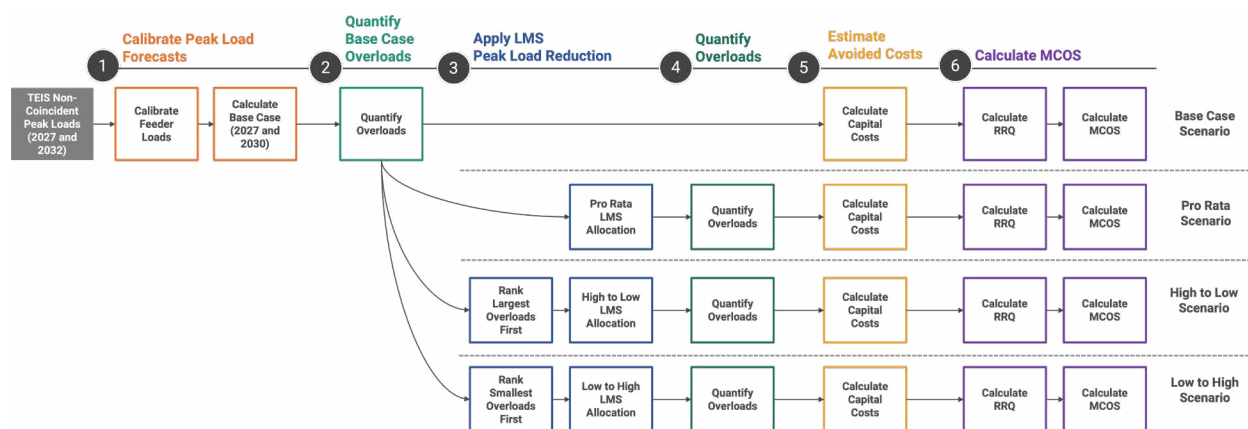
3 NREL, LBNL, Kevala, and U.S. DOE, *Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles*, DOE/EE-2818, U.S. Department of Energy, March 2024.

equipment (EVSE) adoption levels⁴ based on expected U.S. policy. This scenario did not include managed charging for EVs and did not predict any additional legislation to incentivize EV adoptions.

Methodology Overview

To estimate the avoided costs and MCOS, Kevala followed several steps, as outlined in Figure 1.

FIGURE 1. Study approach overview (Source: Kevala)



1. Develop Peak Load Forecasts

This study used the peak loads for each existing asset (excluding the option to transfer loads) and the estimated rated capacities of these existing assets from the TEIS (see Appendix A for a summary of the TEIS). Kevala calibrated the feeder loads from the TEIS’s No Action–Unmanaged scenario and then calculated feeder, substation transformer, and substation forecasts for 2027 and 2030. These forecasts served as the Base Case for this study (see Appendix B for more detail).

2. Quantify Base Load Overloads

Kevala determined capacity overloads for the Base Case for each of the study’s forecast years, 2027 and 2030. A feeder overload was marked when a feeder’s forecasted net load exceeded an adjusted capacity target, set at 80% capacity utilization. To rectify the overload, a new feeder was constructed on the same substation as the overloaded feeder. If a substation transformer also overloaded, a new transformer was built at the substation of the overloaded transformer. If a substation was overloaded, a new substation was built with no assumptions related to the specific location of that substation.

⁴ Kevala’s adoption methodology incorporates EV adoption by class as well as the charging preferences and charging behavior of EVSE.

3. Apply LMS Peak Load Reductions

Kevala determined the LMS targets for 2027 and 2030 by equally distributing 3.5 GW of load reductions from 2025 to 2030. This resulted in 20% of the incremental goal allocated to each year.

After determining capacity overloads for the Base Case, Kevala applied LMS peak load reductions under three scenarios:

- 1. Pro Rata:** The LMS target was equitably allocated across feeders on a pro rata basis based on the peak of each asset (non-coincident peak) and the sum of the non-coincident peaks (contribution to non-coincident peak).
- 2. High to Low:** The LMS target was allocated to relieve feeder capacity needs by assigning LMS peak reductions equal to the capacity overload (i.e., feeder capacity needs were offset). The LMS target was allocated by first ranking feeder overloads from highest to lowest based on the amount capacity was exceeded and then crediting LMS reductions feeder by feeder, in rank order, until the total 3.5 GW LMS goal was met.
- 3. Low to High:** Like the High to Low scenario, the LMS target was allocated to relieve feeder capacity needs by assigning LMS peak reductions equal to the capacity overload (i.e., feeder capacity needs were offset). The LMS target was allocated by first ranking feeder overloads from lowest to highest⁵ and then crediting LMS reductions feeder by feeder, in rank order, until the total LMS goal was met.

4. Quantify Overloads

For each of the three LMS-impacted scenarios, Kevala calculated new overload counts. The High to Low and Low to High scenarios had feeder overloads completely mitigated via the LMS allocation being applied, reducing total overload counts.

5. Estimate Avoided Costs

As noted previously, Kevala estimated LMS benefits in two ways. The first, the avoided cost analysis, compared the total costs of mitigations from the Base Case against each of the three LMS scenarios. This required estimating the total costs for each scenario as determined by the number of new assets needed to eliminate overloads and then taking the difference in those total costs to quantify the benefits. Appendix C details Kevala's avoided cost methodology.

6. Calculate MCOS

Kevala calculated MCOS for each scenario by dividing levelized revenue requirements (RRQ) by the added capacity of new assets. This levelized RRQ was derived by multiplying annual upgrade capital costs by the carrying cost⁶ of the asset. This RRQ represents the amount

⁵ Feeders without overloads were not allocated any LMS peak reduction.

⁶ This study estimated investor-owned utility carrying costs, which are the incremental costs of borrowing to fund the capital need and accounts for return on investment, interest costs, rate of return, depreciation, and taxes.

needed to annually cover upgrade costs for the life of the asset benefit. The capital cost of added capacity of new feeders was based on the number of feeders multiplied by each new feeder's unit cost.

This MCOS value was then applied to the kilowatt-hour (kWh) savings from the LMS target in a given year and extrapolated to a lifetime value, achieving the benefits for 50 years. Appendix D details Kevala's MCOS methodology.

Study Assumptions

This study focuses on the financial benefits of a successful LMS strategy. It does not discuss the design of the various peak load reduction strategies that may be used to meet the LMS goal or the costs of programs needed to achieve the LMS goal. Specifically, this study is designed to calculate total technical potential of avoided distribution grid upgrade costs if the LMS goal is achieved in 2030, and the impact on distribution feeders, substation transformers, and substations under various peak load reduction allocation scenarios.

The study assumes additional capacity is needed on distribution grid assets when utilization exceeds 80%. This includes an incremental 5% buffer for the potential of load transfers among assets and incorporates the logic many utilities use (targeting capacity increases at 75% utilization). The study does not estimate load transfers outside of the 5% buffer nor does it calculate the costs of upgrading or replacing service transformers.

While the TEIS included service transformers, this study did not include them because it does not include the locational consideration of the adoption of the peak reductions. The TEIS was based on a bottom-up forecast assuming adoption and behavior at a parcel level. This study does not develop a similar level of adoption granularity for the peak reductions. To achieve a similar level of granularity as the TEIS, the LMS peak reductions would have to be applied to a parcel and then aggregated up to the feeder. Because this study does not forecast what specific measures will be implemented to achieve the LMS goal, parcel-level peak reduction that would result in avoided service transformer upgrade costs was not in the scope of this study and therefore service transformers and their associated cost savings were excluded.

The study's cost estimates are exclusively based on new capacity rather than lifecycle replacement costs. While it is true lifecycle replacements by 2030 may occur and may lower the costs of new capacity, this study does not take the age of existing assets into consideration when identifying overloads.

This study assumes load growth consistent with the U.S. Energy Information Administration's (EIA's) forecast of load growth, as outlined in the TEIS. The EIA forecast does not include significant load growth from building electrification or new data center load. It also does not include load reductions from photovoltaic systems.

■ Results

This study compared the number of assets overloaded in each scenario, the corresponding capital costs to mitigate overloads with and without LMS peak reductions applied, and then translated those capital costs into MCOS. All LMS scenarios were compared against the Base Case as a control.

Overloads

Table 1 shows total overload counts by asset type for all four scenarios. Substation and substation transformer overload counts were fairly consistent across the three LMS peak reduction scenarios. **Feeder overloads were the most significant mitigated asset.** Applying the LMS peak reduction in the Low to High scenario decreased the overloaded feeder count by over half compared to the other LMS scenarios.

TABLE 1. Total counts of overloads by asset type for the Base Case and each LMS scenario, 2027 and 2030
(Source: Kevala)

2027

ASSET	BASE CASE	PRO RATA	HIGH TO LOW	LOW TO HIGH
Feeder	1,416	1,263	1,284	356
Substation Transformer	439	408	426	411
Substation	80	85	80	80
Total	1,935	1,756	1,790	847

2030

ASSET	BASE CASE	PRO RATA	HIGH TO LOW	LOW TO HIGH
Feeder	2,294	1,938	2,081	633
Substation Transformer	507	459	468	442
Substation	109	106	107	103
Total	2,910	2,503	2,656	1,178

Figure 2 shows the total count of overloaded assets with the associated total capital costs overlaid on top. Both charts are shown on the same y-axis scale for comparison between the study years, 2027 and 2030.

FIGURE 2. Count of overloaded assets by type and total capital costs of upgraded assets, 2027 and 2030
(Source: Kevala)

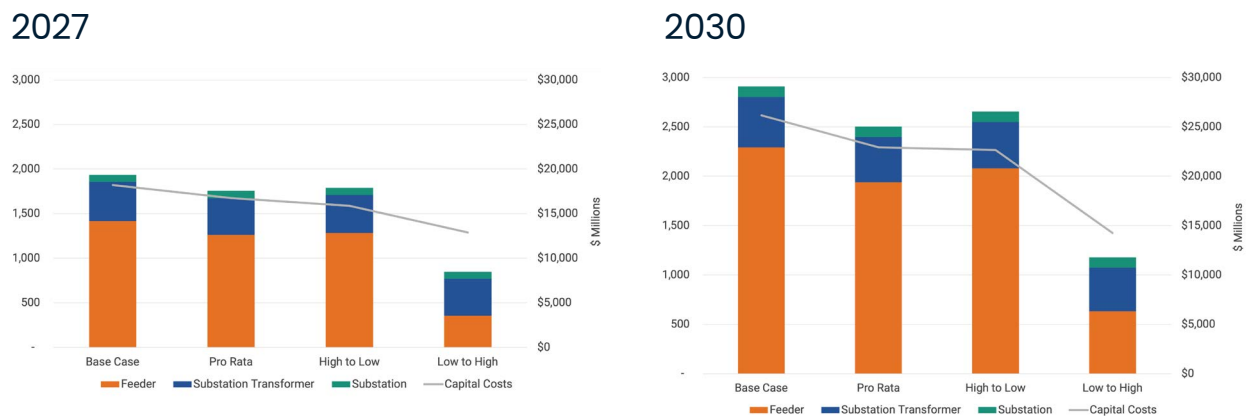


Figure 3 shows the difference in overloaded assets and corresponding costs in the LMS scenarios as compared to the Base Case. Negative values indicate a reduction in overloads or costs. In all scenarios, the total capital costs are reduced when any amount of peak reduction is applied.

FIGURE 3. Count of overloaded assets by type and total capital costs of upgraded assets, 2027 and 2030
(Source: Kevala)



Figure 4 and Table 2 show the total count of overloaded feeders by urbanization category. **Feeders in urban areas have higher overload counts than both suburban and rural, and also have higher mitigation costs.**

FIGURE 4. Count of overloaded feeders by urbanization category, 2027 and 2030 (Source: Kevala)

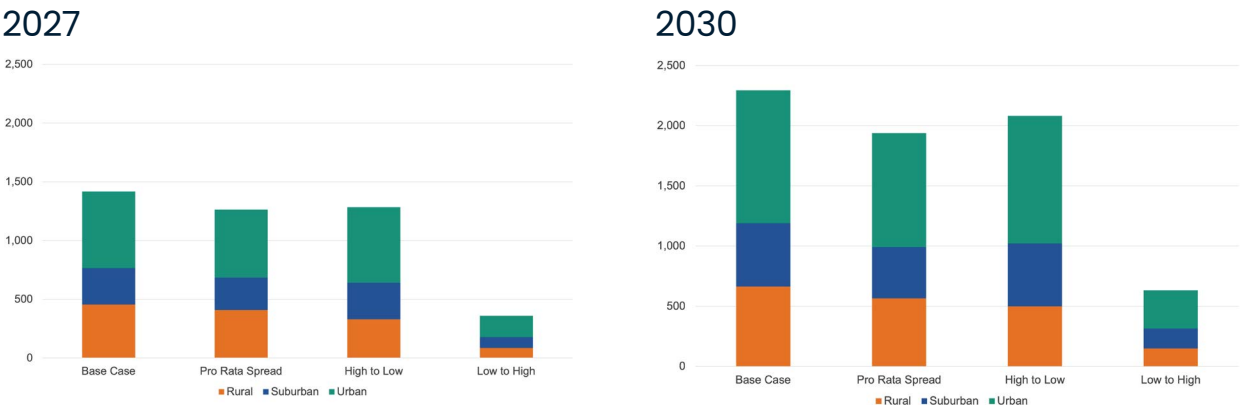


TABLE 2. Number of overloaded feeders by urbanization category for the Base Case and each LMS scenario, 2027 and 2030 (Source: Kevala)

2027							
URBANIZATION CATEGORY	BASE CASE	PRO RATA	DELTA	HIGH TO LOW	DELTA	LOW TO HIGH	DELTA
Rural	454	408	-46	329	-125	86	-368
Suburban	312	276	-36	311	-1	88	-224
Urban	650	579	-71	644	-6	179	-468
Total	1,416	1,263	-153	1,284	-132	356	-1,060

2030							
URBANIZATION CATEGORY	BASE CASE	PRO RATA	DELTA	HIGH TO LOW	DELTA	LOW TO HIGH	DELTA
Rural	663	566	-97	499	-164	149	-514
Suburban	526	425	-101	523	-3	165	-361
Urban	1,105	947	-158	1,059	-46	319	-786
Total	2,294	1,938	-356	2,081	-213	633	-1,661

Table 3 shows the number of assets still overloaded after LMS peak load reductions were applied. In the Pro Rata scenario, all assets received a portion of load reduction, though the amount applied may not have fully alleviated an asset’s overload.

The High to Low and Low to High scenarios resulted in some feeders receiving no allocation of peak load reductions because the higher ranked feeders exhausted the 3.5 GW goal before overloads were mitigated on all feeders. In the High to Low scenario, allocating the LMS peak reductions starting with the feeders with the highest capacity overload resulted in the lowest quantity of overloaded feeders mitigated. Conversely, the Low to High scenario resulted in the greatest number of feeder overloads mitigated.

The Low to High scenario avoided overloads in approximately 1,000 more feeders than the Base Case and approximately 900 more feeders than the Pro Rata or High to Low scenarios. The next most efficient peak load reduction scenario (Pro Rata) reduced more overloads than the High to Low scenario and the Base Case. Reducing the load on more feeders with smaller overloads (as in the Low to High scenario) resulted in significant reductions in total overload counts comparatively.

TABLE 3. Number of feeders receiving LMS allocation compared to overloaded asset count *(Source: Kevala)*

2027

2027	Base Case		Pro Rata		High to Low		Low to High	
Asset	Assets Overloaded	Assets Receiving LMS Allocation	Assets Still Overloaded	Assets Receiving LMS Allocation	Assets Still Overloaded	Assets Receiving LMS Allocation	Assets Still Overloaded	
Feeder	1,416	8,836	1,263	124	1,284	1,260	356	
Substation	80	2,134	85	727	80	727	80	

2030

2000	Base Case		Pro Rata		High to Low		Low to High	
Asset	Assets Overloaded	Assets Receiving LMS Allocation	Assets Still Overloaded	Assets Receiving LMS Allocation	Assets Still Overloaded	Assets Receiving LMS Allocation	Assets Still Overloaded	
Feeder	2,294	8,836	1,938	151	2,081	1,657	633	
Substation	109	2,134	106	864	107	864	103	

Avoided Distribution Costs from Overloads

Reducing the total number of asset overloads directly correlates to reductions in the capital costs calculated for mitigation. **Using LMS peak reductions to reduce smaller overloads on more feeders is far more cost-effective than reducing the load on a smaller number of feeders with the most extreme overloads.** Because the cost of new assets is the same for a feeder with a large overload as one with a small overload, the more feeders mitigated, the higher the cost savings.

Table 4 shows total capital costs and the reduction (delta) in total capital costs compared to the Base Case for all three LMS scenarios, broken out by asset type. Depending on the scenario, LMS allocation reduced estimated distribution capital costs from \$3.2 to \$11.9 billion in 2030. Taking into account the carrying costs associated with these capital expenditures, the total present value⁷ to customers ranges from \$3.7 to \$13.7 billion.

The Low to High scenario, with the fewest overloads after LMS peak reductions, had the lowest total capital costs in both years. The Pro Rata and High to Low scenarios had similar capital costs and were much closer to the capital costs for the Base Case.

TABLE 4. Capital cost and comparison against the Base Case (\$ millions) by LMS scenario and asset type, 2027 and 2030 (Source: Kevala)

2027

ASSET TYPE	BASE CASE	PRO RATA	DELTA	HIGH TO LOW	DELTA	LOW TO HIGH	DELTA
Feeder	\$10,846.3	\$9,951.8	\$(894.4)	\$4,020.8	\$(1,641.4)	\$4,020.8	\$(6,825.5)
Substation Transformer	\$4,394.7	\$4,123.8	\$(270.8)	\$4,155.0	\$(239.7)	\$4,155.0	\$(239.7)
Substation	\$2,969.0	\$2,658.0	\$(311.0)	\$2,510.0	\$(459.0)	\$2,510.0	\$(459.0)
Total	\$18,209.9	\$16,733.7	\$(1,476.3)	\$15,869.8	\$(2,340.1)	\$10,685.8	\$(7,524.2)
Present Value		\$1,701.7		\$2,697.3		\$6,145.6	

2030

ASSET TYPE	BASE CASE	PRO RATA	DELTA	HIGH TO LOW	DELTA	LOW TO HIGH	DELTA
Feeder	\$16,686.1	\$14,507.1	\$(2,179.0)	\$14,160.2	\$(2,525.9)	\$6,135.1	\$(627.7)
Substation Transformer	\$5,136.9	\$4,692.3	\$(444.6)	\$4,802.6	\$(334.3)	\$4,509.2	\$(627.7)
Substation	\$4,355.0	\$3,736.0	\$(619.0)	\$3,701.0	\$(654.0)	\$3,611.0	\$(744.0)
Total	\$26,178.0	\$22,935.4	\$(3,242.6)	\$22,663.7	\$(3,514.3)	\$14,255.3	\$(11,922.7)
Present Value		\$3,737.7		\$4,050.8		\$13,743.1	

Figure 5 depicts the changes in capital required for each scenario. The charts use the same y-axis scale for comparison. The most impactful capital cost contribution comes, again, from building feeders. The Low to High scenario significantly reduces the number of feeder builds and the capital cost contribution. The capital costs for substations and substation transformers are relatively steady across the Base Case and the three LMS scenarios.

⁷ Present value is calculated by discounting the future value, in this case the value in 2027 or 2030, by the estimated rate of return that the money could earn if invested.

FIGURE 5. Capital costs (\$ millions) for the Base Case and each LMS scenario by asset type, 2027 and 2030



Marginal Cost of Service

Table 5 provides the annual MCOS of capacity added for the Base Case and each scenario, comparing the cost per kilowatt (kW) of the LMS scenarios against the Base Case. The MCOS per kW is lowest for the Low to High scenario because the costs are significantly lower relative to the capacity reduction. This stems from the reduced number of overloads identified after the LMS peak reductions were applied.

TABLE 5. MCOS (\$/kW) for the Base Case and each LMS scenario by asset type, 2027 and 2030

(Source: Kevala)

2027							
ASSET	BASE CASE	PRO RATA	DELTA	HIGH TO LOW	DELTA	LOW TO HIGH	DELTA
Feeder	\$33.03	\$33.44	\$0.41	\$32.40	\$(0.64)	\$35.25	\$2.21
Substation Transformer	\$13.38	\$13.86	\$0.47	\$14.62	\$1.24	\$11.48	\$(1.90)
Substation	\$9.04	\$9.04	\$(0.11)	\$8.93	\$(0.21)	\$6.93	\$(2.11)
Total	\$55.46	\$56.23	\$0.77	\$55.85	\$0.39	\$53.66	\$(1.80)
Capacity Added (MW)	29,170	26,440	-2,730	25,242	-3,928	10,134	-19,036

2030							
ASSET	BASE CASE	PRO RATA	DELTA	HIGH TO LOW	DELTA	LOW TO HIGH	DELTA
Feeder	\$32.86	\$33.65	\$0.80	\$39.12	\$6.26	\$24.99	\$(15.91)
Substation Transformer	\$10.12	\$10.89	\$0.77	\$13.27	\$3.15	\$18.37	\$2.34
Substation	\$8.58	\$8.67	\$0.09	\$10.23	\$1.65	\$14.71	\$1.40
Total	\$51.55	\$53.21	\$1.66	\$62.62	\$11.07	\$58.07	\$(12.17)
Capacity Added (MW)	45,114	38,296	-6,818	32,156	-12,958	21,811	-23,303

The Low to High scenario had the lowest total MCOS in 2027 and second highest in 2030, which is consistent with the avoided costs results. It is worth noting the High to Low scenario feeder MCOS is higher than in the Low to High scenario. This is driven by a significant number of the feeders needed to mitigate overloads in high-cost areas (i.e., urban) coupled with the limited amount of capacity added (10 GW in 2027 and 22 GW in 2030) in the Low to High scenario as compared to the High to Low scenario (25 GW in 2027 and 32 GW in 2030). A higher capital cost is allocated across a larger amount of capacity added in the High to Low scenario, resulting in a reduced feeder MCOS.

MCOS results are driven by multiple factors, including assets, added capacity, and the urbanization category of the assets. This means the urbanization category of a new asset, and therefore its unit cost, will impact its MCOS. In other words, if fewer urban feeder overloads are mitigated, the capital cost will be lower overall, but the MCOS will be higher due to the reduced capacity added. For example, the Low to High scenario has fewer overall assets added, though a higher proportion of them are categorized as urban, so the feeder MCOS in that scenario is higher than the others.

The Low to High scenario incurs \$10.7 million in total capital costs in 2027 with 10 GW new capacity added. This results in roughly \$1 million per new GW added to the system (see Table 6). Comparatively, the High to Low scenario incurs \$15.9 million in total capital costs in the same year but with double the capacity added, 25 GW, where each MW added costs \$0.63 million, half the result of the Low to High scenario. This highlights the importance of understanding the MCOS, which represents the relationship between capacity and capital costs.

TABLE 6. Capital costs (\$ millions) per MW added for the Base Case and each LMS scenario, 2027 and 2030
(Source: Kevala)

2027

	BASE CASE	PRO RATA	HIGH TO LOW	LOW TO HIGH
Total Capital Costs (\$M)	\$18,209.9	\$16,733.7	\$15,869.8	\$10,685.8
Capacity Added (MW)	29,170	26,440	25,242	10,134
\$ Millions / MW	\$0.62	\$0.63	\$0.63	\$1.05

2030

	BASE CASE	PRO RATA	HIGH TO LOW	LOW TO HIGH
Total Capital Costs (\$M)	\$26,178.0	\$22,935.4	\$22,663.7	\$14,255.3
Capacity Added (MW)	45,114	38,296	32,156	21,811
\$ Millions / MW	\$0.58	\$0.60	\$0.70	\$0.65

Comparison to Other Studies

In addition to the TEIS, Kevala conducted an Electrification Impacts Study (EIS) for the California Public Utilities Commission (CPUC).⁸ Kevala compared the cost results of this study with those studies to determine why there are differences. Table 7 shows this comparison for 2030, a common year across all studies. The results shown are all for substations, substation transformers, and feeders; they do not include service transformers, as were broken out in the other studies. The results for the TEIS and this study were adjusted down 20% to account for the TEIS including all of California, while the CPUC EIS was only for the three major investor-owned utilities.

TABLE 7. Comparison of results to previous studies (*Source: Kevala*)

STUDY	SCENARIO	2030	2032
TEIS	No Action-Unmanaged		\$16.2 billion
CPUC EIS	Base Case 2021 IEPR	\$13.5 billion	
	High Transportation Electrification + Existing BTM Tariffs	\$16 billion	
GridLab Study	Base Case	\$17.4 billion	
	Base Case (100% Utilization Hurdle)	\$11.6 billion	

The results from the Base Case of this study are the highest of all the studies, primarily due to the change in assumption of the trigger for asset overloads. Specifically, the CPUC EIS and TEIS assumed overloads triggered new builds only when utilization exceeded 100% while this study assumed triggering at 80% utilization. To confirm the higher results from the Base Case were based primarily on the assumption that planning would be done based on an 80% utilization rather than 100% utilization, Kevala ran the same analysis for the Base Case using 100% utilization to more closely match the methodology used in the CPUC EIS and TEIS studies (see the last row of Table 7).

The difference between the TEIS and this study was influenced by including (TEIS) or excluding (this study) load transfers. Kevala also reviewed the High Transportation Electrification + Existing BTM Tariffs scenario from the CPUC EIS because the IEPR assumptions assumed very conservative EV adoptions compared to the TEIS No-Action-Unmanaged scenario.

⁸ Kevala, Inc., *Electrification Impacts Study Part I: 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.



■ Conclusions and Recommendations

This study highlights the importance and impact of a targeted application of load savings and the importance of feeder-level forecasting versus system-level savings. The distribution of load savings across feeders, substation transformers, and substations reduces the number of asset overloads in the LMS scenarios as compared to the Base Case, and there are **notable savings from the LMS peak reductions regardless of the strategies used to achieve the goal and the urbanization category of the load reductions.**

Key findings include:

- The cost savings from the Pro Rata scenario were \$3.2 billion of total capital costs in 2030 compared to the Base Case.
- The Low to High scenario reduced capital costs by \$11.9 billion in 2030 compared to the Base Case.
- The total savings to customers (in present value dollars) by reducing capital costs through LMS allocation was estimated to be between \$3.7 and \$13.7 billion.
- The Pro Rata scenario and High to Low scenario produced similar cost reductions.
- The Low to High scenario yielded the highest reduction in costs because more feeder overloads were mitigated.
- The number of feeders impacted by the Low to High scenario addressed more urban feeders (on a percentage basis) relative to other urbanization categories, which accounted for more cost savings because urban assets had higher unit costs per MW of capacity.

- Benefits quantified by MCOS approach did not vary as greatly as with the avoided cost approach. This is because MCOS were computed based on the cost per kW of savings, which only varied from one scenario to another based on urbanization category.

The method in which the LMS is allocated among assets (Pro Rata, High to Low, or Low to High) can have a significant impact on total capital costs and MCOS. Specifically, **targeted allocation of LMS to reduce the highest number of overloaded feeders results in the greatest cost savings.**

An asset's urbanization category (i.e., urban, suburban, or rural) also impacts the costs. Specifically, urban feeders cost 25%–50% more per linear foot than rural and suburban feeders (depending on the voltage), and underground feeders are more than five times the cost of aboveground feeders. Interestingly, the average length of feeders in urban areas is greater than the average length of rural and suburban feeders. All together, feeders in urban areas cost more to build than rural ones. For this reason, it may be beneficial to target LMS peak reductions in urban areas.

A direct avoided cost method based on individual asset cost savings resulting in more significant differences in benefits than an MCOS analysis emphasizes the need for both types of analyses to obtain a complete picture of benefits from efforts to reduce peak loads in general and the LMS in particular. Also, the difference in costs based on urbanization category versus not considering an asset's physical location is important because, though the MCOS vary slightly in this comparison, the location is important to optimize the value of LMS peak reductions. It also highlights how tools such as the Avoided Cost Calculator, which effectively takes system-level marginal costs to compare peak load reductions, does not provide a complete picture of how to maximize the potential benefits of peak load reduction efforts.

While this study provides insight on how the allocation of LMS peak reductions impacts costs and overloaded assets, these quantifications are based on certain assumptions. Future studies using this approach could:

- **Evaluate program designs for LMS application** by taking the cost savings and applying them to current programs based on if a program tackles a specific coincident peak time. This analysis may provide additional insight into whether programs are run at their most efficient times or if there is a correlation between when the distribution costs are at their highest and the established programs.
- **Calculate overloads using a different capacity threshold.**
 - The 80% capacity threshold was chosen based on Kevala's understanding of how typical planners evaluate a system. Increasing or decreasing this threshold will shift the overloads relatively.
 - The capacity threshold may also differ between substations, substation transformers, and feeders.

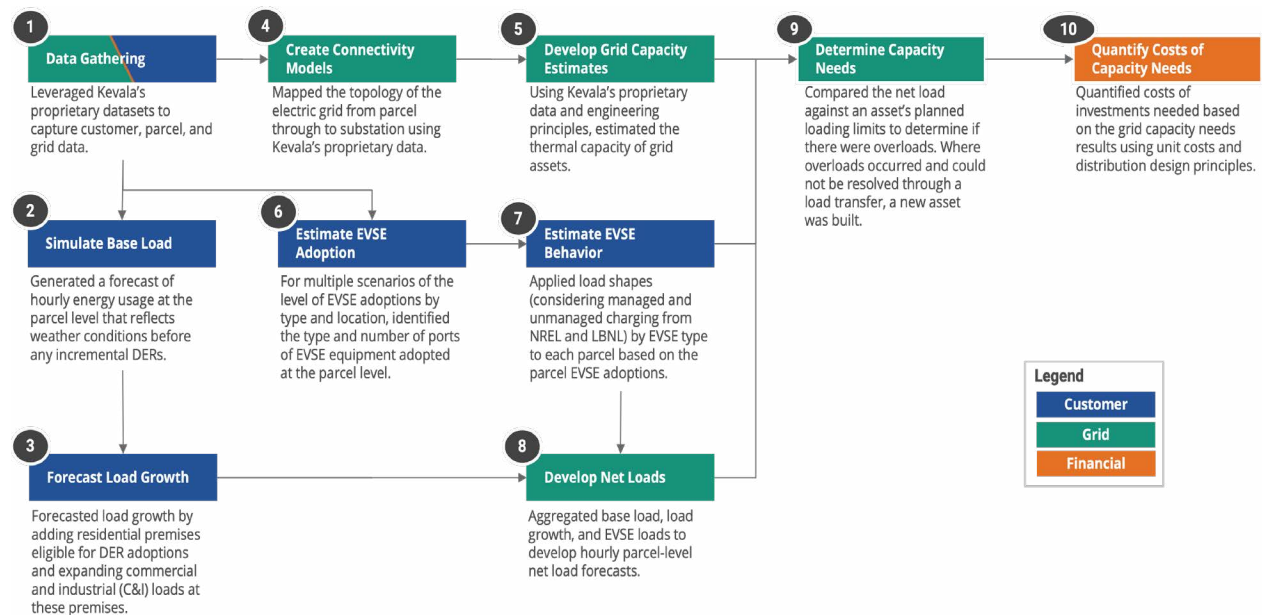
- **Develop hourly MCOS that can be compared to the marginal costs in the Avoided Cost Calculator** and show the distribution of possible outcomes against a range of distributed energy resource (DER)/non-wires alternative (NWA) options (an hourly load shape of the NWA option would be needed in this scenario).
 - This study was conducted on feeder non-coincident peak times. If the study was prepared in such a way to develop 8760 datasets for each year, the MCOS for each scenario could be calculated at the hourly level.
 - This hourly load shape for each asset would allow the analysis against any DERs adopted on the feeder, shifting its peak value depending on the DER. This hourly load shape could also be applied to evaluate the impact and effectiveness of NWA options.
- **Develop geospatial visualization of the overloads and capacity amounts to identify hot spots.** Based on the findings that the asset's urbanization category impacts the resulting MCOS, mapping feeders or substations with high overloads may lead to the identification of a high risk area. These assets could be targeted or ranked higher to receive larger allocations of the LMS peak reductions sooner to alleviate these overloads.

Appendix A

TEIS Summary

This study utilized a subset of results from the Multi-State Transportation Electrification Impact Study (TEIS),⁹ which were then calibrated to inputs specific to this study. Figure A-1 shows an overview of the TEIS methodology.

FIGURE A-1. Overview of the TEIS methodology (Source: Kevala)



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

- California
- Illinois
- Pennsylvania
- New York
- Oklahoma

⁹ NREL, 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.

For each state, Kevala developed a baseload forecast, at the parcel level, using the National Renewable Energy Laboratory's (NREL's) ResStock¹⁰ and ComStock¹¹ 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 the initial study, four scenarios were run in each of the five states for 2027 and 2032:

- **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.

In addition, Kevala ran capacity-aware managed charging scenarios for each state for 2027 and 2032:¹²

- **No Action-Capacity Aware Managed:** This scenario included managed charging to minimize daily peak demand on a feeder without any future legislative impacts to EVSE adoptions.
- **Action-Capacity Aware Managed:** This scenario included managed charging to minimize daily peak demand on a feeder and future legislative impacts to EVSE adoptions.

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.

¹⁰ NREL, ResStock: <https://resstock.nrel.gov/>

¹¹ NREL, ComStock: <https://comstock.nrel.gov/>

¹² Kevala developed and implemented the capacity-aware managed charging model as an extension to the original scope of the TEIS. The model criteria and results are detailed in Appendix E of the [TEIS report](#).

Appendix B

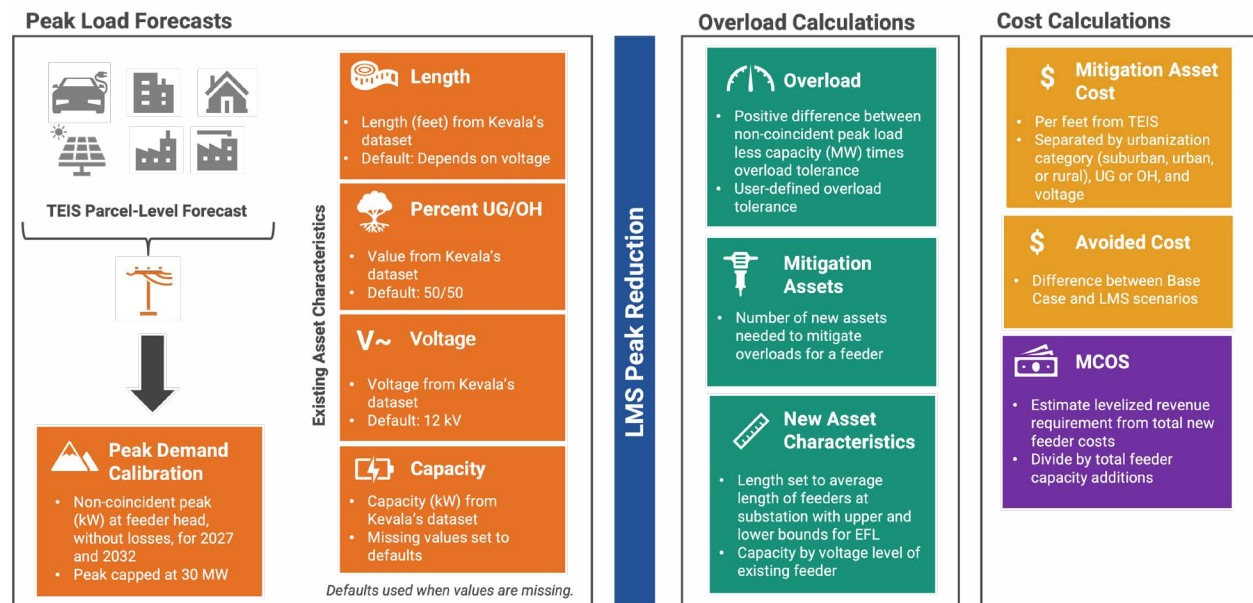
Overload and Cost Estimation Methodology

While the Transportation Electrification Impact Study (TEIS) estimated costs, Kevala did not use these costs because they were influenced by assumed load transfers and calculated overloads when assets were at 100% utilization. For this study, Kevala used the non-coincident peak load for each existing asset (excluding the option to transfer load), estimated rated capacities of these existing assets, and calculated the costs per overload using the unit costs from the TEIS.

Feeder Overloads and Costs

Figure B-1 outlines the approach to estimating feeder overloads and the related cost to mitigate the overloads. This is a subset of the complete study flow shown in Figure 1. Further detail on the Load Management Standard (LMS) scenarios and peak load application to calculate avoided costs is included in Appendix C. The marginal cost of service (MCOS) methodology is discussed in Appendix D.

FIGURE B-1. Overview of feeder overload determination and cost calculation approach (Source: Kevala)



Peak Load Forecasts

Starting with a 2023 base load forecast, the TEIS developed non-coincident peak load forecasts for all California feeders for 2027 and 2032, but the study did not have an explicit forecast for the 2030 LMS target year. Consequently, Kevala used a linear interpolation between the 2027 and 2032 loads to develop a 2030 forecast, and developed non-coincident peak load forecasts for 2027 and 2030 for each feeder. For this study, the non-coincident peak load of a feeder was estimated for 2027 and 2030 using the TEIS's No Action-Unmanaged scenario from the TEIS.

Peak 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 2023.

Existing Asset Characteristics

Kevala used the TEIS values for key feeder characteristics—length, urbanization category, percent underground (UG) and overhead (OH), voltage, and capacity (kW)—to represent the existing capacity of the grid. Any missing feeder characteristic data was backfilled using the following default values:

- Feeder length (feet):
 - 2,091.7 if voltage was between 0 kV and 8 kV
 - 6,114.2 if voltage was between 9 kV and 18 kV
 - 11,423.9 if voltage was between 19 kV and 27 kV
 - 15,607.3 if voltage was above 27 kV
- Underground (UG) percentage: 50%
- Feeder voltage: 12 kV
- Capacity: 30 MW
- Urbanization category: Suburban

Overload Calculations

When identifying overloads, Kevala used the non-coincident peak for a feeder and subtracted 80% of the capacity (overload tolerance). When this value was positive, the non-coincident feeder peak exceeded the adjusted capacity and an overload on the feeder was marked.

Kevala summed the count of mitigation assets needed by feeder. In some cases, an overload needed more than a single new feeder to eliminate the overload.

Kevala estimated the new asset characteristics for a new feeder at a substation based on the existing feeders on the substation. The maximum voltage of any new feeder on a substation was set as the voltage of the typical feeder, and the capacity was then set based on the voltage (see Table B-1). Kevala estimated the length of the new feeder by taking the average length of all feeders on the substation and then taking the lower of the average length and two times the economic load reach (ELR) to establish the new feeder’s voltage. Using this calculated voltage, the capacity was estimated as the greater of the average of the substation’s feeder length and 20% of the ELR.

TABLE B-1. New feeder capacity based on voltage (*Source: Kevala*)

VOLTAGE (KVA)	CAPACITY (KW)
≥13	16
≤24	24
≤34	30

Overloads were first calculated for the Base Case. As described in Appendix C and shown in Figure 1, based on the LMS allocation, Kevala applied capacity reductions to the peak loads and then recalculated the number of overloads. Base Case overloads were only calculated once.

Cost Calculations: Mitigation Asset Cost

The final step was calculating the unit costs of the new feeder. All new feeders on a substation were calculated to have the same physical characteristics and therefore the same cost. The individual asset characteristics of the new feeder described above impacted the total unit cost.

The feeder’s cost was determined by its urbanization category as the price of overhead and underground lines vary. The exact percentage of overhead and underground lines was based on all the feeders on the substation. The cost per foot of line varied based on its voltage and whether it was overhead or underground. These individual costs were included in the cost of the new asset (see Table B-2).

TABLE B-2. Feeder cost by urbanization category, line type, and voltage (Source: Kevala)

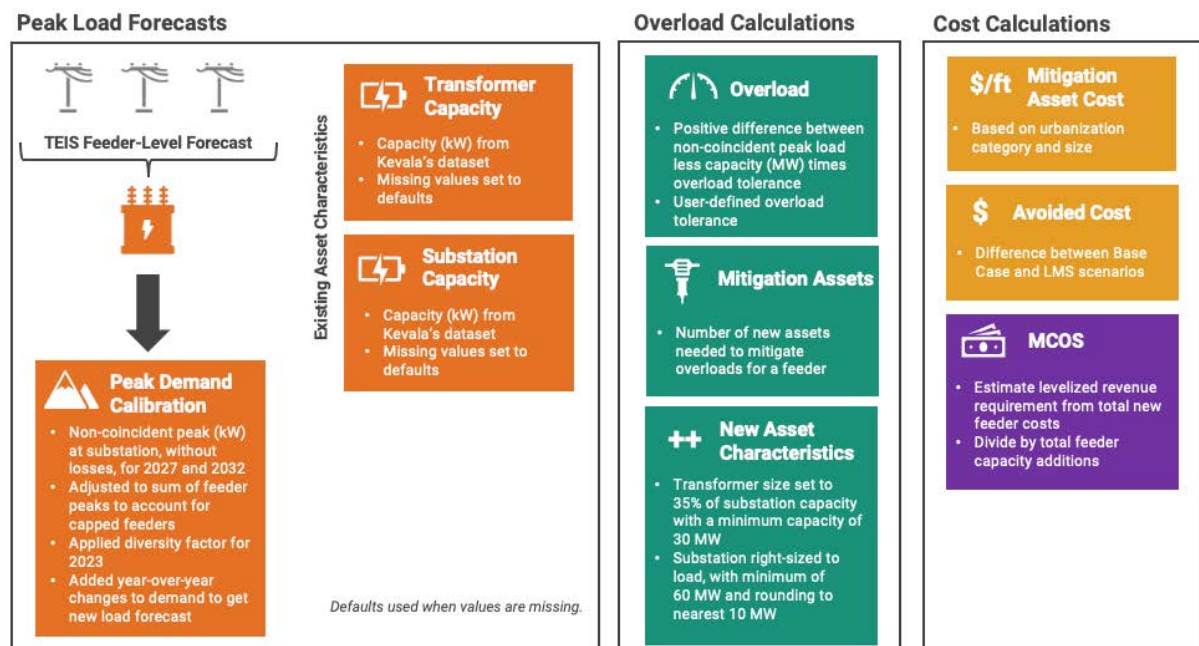
URBANIZATION CATEGORY	LINE TYPE	VOLTAGE <25 KVA (\$/FT.)	VOLTAGE ≥25 KVA (\$/FT.)
Rural	OH	\$100.00	\$250.00
	UG	\$558.27	\$1,395.68
Urban	OH	\$156.00	\$312.50
	UG	\$872.3	\$1,744.61
Suburban	OH	\$100.00	\$250.00
	UG	\$558.27	\$1,395.68

The analysis looked at each study year individually. That is, the costs in 2030 are total capital costs for that year and do not include any potential overload mitigations coming online before 2027.

Substation Equipment Overloads and Costs

Substation transformer and substation overloads were also examined as part of this study. Figure B-2 outlines the approach used to estimate overloads and the related cost to mitigate these overloads for substation assets. This is a subset of the complete study flow shown in Figure 1. Further detail on the LMS scenarios and peak load application to calculate avoided costs is included in Appendix C. The MCOS methodology is discussed in Appendix D.

FIGURE B-2. Overview of substation asset overload and cost calculation approach (Source: Kevala)



Peak Load Forecasts

Kevala aggregated the peak demand (non-coincident peak) for all feeders on a substation. The substation peaks from the TEIS study were compared to these aggregated feeder peak values on the substation to determine an average diversity factor. This factor was applied to each cumulative peak for each substation to account for possible discrepancies between the sum of non-coincident feeder peaks and the TEIS substation peak.

Existing Asset Characteristics

Kevala used the TEIS estimates of substation transformer and substation size to represent the existing substation capacity, in the same way as feeders. If a substation or substation transformer did not have values associated with it, default values were used.

Overload Calculations

Kevala examined if a new substation transformer or substation was needed based on the aggregated feeder non-coincident peaks on the asset. Substation overloads were calculated based on the physical capacity of the substation at the same tolerance limit as feeders (80% capacity).

- If a substation transformer was overloaded, a new substation transformer was added and the size (MW) was set to 30 MW if the substation was less than 100 MW; otherwise the new substation transformer was sized to be 35% of the existing substation capacity.
- If the loads still exceeded these limits (greater than 30% of the substation size or 30 MW), a new substation was built. The size of the new substation defaulted to the maximum of 60 MW or the total level of capacity needed to meet the load.

Cost Calculations: Mitigation Asset Cost

The final step was to estimate the costs based on the TEIS unit costs (see Table B-3 and Table B-4). Substation transformer costs were based on the substation size and whether it was greater than 30 MW capacity. Substation transformers did not have different costs based on urbanization categorization like feeders and substations.

TABLE B-3. New substation transformer costs (\$ millions) based on 30 MW or higher calculated capacity
(Source: Kevala)

ASSET	30 MW	OVER 100 MW, 35% OF EXISTING CAPACITY
Transformer	\$10	\$0.3

Table B-4 shows the cost for a new substation based on its urbanization category (suburban, urban, or rural) and calculated capacity to mitigate an overload. The cost increased incrementally for every 10 MW over 60 MW; this incremental value is shown in the second column.

TABLE B-4. New substation cost by urbanization category and calculated capacity (\$ millions) *(Source: Kevala)*

URBANIZATION CATEGORY	60 MW	INCREMENTAL INCREASE (PER 10 MW OVER 60 MW)
Rural	\$20	\$0.3
Suburban	\$30	\$0.4
Urban	\$60	\$0.5

■ Appendix C

Total Avoided Cost Methodology

Starting with the year 2023, Kevala incrementally distributed 2 GW of the Load Management Standard (LMS) goal across each year up to 2027. The goal allocation for 2030 was estimated as the same incremental increase (0.5 GW/year) from 2027 to 2030. This allowed the 2027 allocation to persist through 2030, resulting in only incremental LMS being allocated in 2030.

Overloads and capacity additions were calculated as described in Appendix B after the load was allocated across the feeders based on the three LMS scenarios. Note that any new capacity added in 2027 as a result of building a new asset was not considered in the total system capacity in 2030. In other words, if a new feeder was built in 2027, thereby doubling the capacity of the initial feeder, the doubled capacity was not considered when calculating overloads in 2030—only the initial capacity of the original feeder.

Kevala then calculated avoided costs (i.e., capital costs) based on the resulting overloads and compared the results against the other scenarios.

Load Allocation Scenarios

The load allocation scenarios described focus on application to feeders. Kevala analyzed substations and substation transformers using the same approach as described for feeders for all three scenarios.

Pro Rata

The Pro Rata scenario allocated LMS peak reductions (3.5 GW) across each feeder in the system based on the feeder's non-coincident peak in proportion to the sum of all feeders' non-coincident peaks. Kevala calculated each feeder's non-coincident peak load in 2027 and ranked it against the other non-coincident feeder peaks. This percentage was then multiplied by the amount of load to be allocated across the system by 2027 (2.0 GW) such that each feeder peak decreased the applicable amount.

Kevala used the resulting LMS-adjusted peak loads to determine the number of new feeder, substation transformer, and substation builds as a result of overloads. Costs for these new builds were calculated based on their size and urbanization category.

Non-coincident peaks for each feeder were calculated for 2030. Kevala reduced these peak values by the same peak load reduction allocated to that feeder in 2027, resulting in a new LMS-adjusted non-coincident feeder peak that incorporated the reduction of peak load by LMS allocation in 2027. This adjusted peak was used to calculate the ratio of the LMS-adjusted feeder peak to the sum of LMS-adjusted feeder peaks and the resulting ratio multiplied by the total 2030 LMS goal. The amount of 2030 LMS reduction for that peak was applied to the LMS-adjusted peak for each feeder as the 2030 feeder peak.

Kevala then used this new adjusted peak value to calculate feeder overloads. Any capacity added in 2027 was not included in the capacity total used in the calculation of overloads for 2030.

High to Low

This scenario allocated the LMS target across feeders with the highest recorded overload first until the capacity allocation amount was reached. To do this, Kevala ranked overloaded feeders based on the extent of the overload total—that is, feeders with the highest load over their capacity were ranked higher than smaller overloads (feeders with minimal load over their capacity threshold).

Using this ranking, the LMS target was allocated to the feeders at an amount necessary to avoid an overload, starting with the feeder with the highest overload total and therefore the highest priority rank. Feeder overloads were fully reduced (LMS applied to the full amount of the overload) in their ranked order until the LMS goal was reached. The last feeder receiving any amount of peak reduction may only receive an incremental alleviation of its overload as the LMS reduction was applied until the LMS goal was achieved.

Low to High

This scenario is similar to the High to Low scenario described previously, with the ranking order reversed (i.e., applying LMS reduction such that an overload is mitigated to the feeder with the lowest amount of feeder overload).

Calculating Avoided Costs

Avoided costs were defined as yearly capital costs multiplied by the LMS load reductions for that feeder. This estimate represents the value of the capacity needed and is comparable against the LMS scenarios. For the avoided costs of substations and substation transformers, the sum of all substation and substation transformer costs were computed for each scenario.

For 2027 calculations, the marginal cost was multiplied by the LMS allocation amount. For 2030, the marginal cost of 2027 and 2030 were summed and then multiplied by the sum of the capacity savings in 2027 and 2030. This compounds the savings from the two years into a single value.

Inputs and Assumptions

Each of the three LMS scenarios assumed the following:

- Load allocations started in 2023.
- The entirety of the 3.5 GW savings is achieved by 2030.
- Capacity additions added in 2027 as a result of overloads were not considered in the capacity calculation of overloads in 2030.
- LMS peak reductions were applied until the full LMS amount was completely depleted. The last eligible feeder in the High to Low and Low to High scenarios may only receive an incremental overload reduction (set to the balance of the LMS).

■ Appendix D

Marginal Cost of Service Methodology

The capital cost of added capacity of new feeders was based on the number of feeders added as well as the length and voltage of those feeders. Kevala calculated marginal costs of service (MCOS) by dividing the levelized revenue requirements found for each scenario, including the Base Case, by the added capacity of new assets.

Calculating MCOS

Kevala transformed the capital costs calculated using the avoided distribution cost approach (see Appendix C) into annual MCOS for the Base Case and each Load Management Standard (LMS) scenario. These costs represent the total dollars used as the annual revenue requirement (RRQ) for 2027 and 2030.

Levelized RRQ were derived by multiplying annual upgrade capital costs by the carrying cost of the asset. This RRQ represents the amount needed to annually cover upgrade costs for the life of the asset benefit.

Kevala first calculated returns on the assets using the following formula:

$$R = ROE \times \left(\frac{1}{(1 - Taxes)} \right) \times EquityRatio + Int \times DebtRatio$$

Where the variables are defined as:

- Return on equity (ROE): 10.00%
- Corporate tax rate (combined state and federal): 20.00%
- Capital structure:
 - Equity ratio: 50.00%
 - Debt ratio: 50.00%
 - Cost of debt (int): 5.00%

R resulted in 8.750% and was used to calculate the carrying costs¹³ of feeders and substations using the following formula, where R is the calculated return and L is the lifetime of an asset:

$$CC^a = \frac{R \times (1 + R)^L}{(1 + R)^L - 1}$$

Carrying costs (CC^a) for feeders and substations was 8.88%. This value was multiplied against the upgrade costs for the Base Case and after the LMS peak load reduction was applied to the load, resulting in levelized RRQ.

MCOS were calculated by dividing the levelized RRQ by the capacity added in the year:

$$RRQ_y^a = \left(\frac{Capital_y^a}{Capacity\ Added_y^a} \right) \times CC^a$$

Where the variables are defined as:

- RRQ_y^a is the annual marginal cost per kW of capital dollars.
- $Capital_y^a$ is the total upgrade costs in a year (2027 or 2030).
- $Capacity\ Added_y^a$ is the total capacity added to the system in a year (y) through new asset builds.
- CC^a is the calculated carrying cost of 8.88%.

The MCOS were summed and compared by year for the Base Case and the three LMS scenarios.

Inputs and Assumptions

The following assumptions were made while developing this MCOS study:

- The costs for new assets differed from the TEIS cost estimates based on updated assumptions from the original report (see Appendix B).
- Both feeder and substation asset lifetime was estimated at 50 years.
- For substation transformers and substations, the levelized RRQ of the capital costs was divided by the total feeder capacity added. This is based on the assumption that the individual feeders overloading are causing upstream overloads in substations and substation transformers and those capital costs should be attributed to all customers on the substation.

¹³ Carrying costs are the incremental costs of borrowing to fund the capital need and accounts for return on investment, interest costs, rate of return, depreciation, and taxes. This study estimated investor-owned utility carrying costs, understanding that the 20% of avoided upgrades that occur in publicly owned utility territory will have lower carrying costs.



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