Code Switch: Energizing Efficient Buildings for a Renewable Future

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ABSTRACT

California's building energy code evaluates efficiency measures based on their Long-Term System Cost (LSC), a metric that captures the present value of 30-year costs to the statewide energy system. The LSC reflects not just how much energy a building uses, but when that energy is consumed relative to periods of grid stress. As California has integrated increasing shares of solar and wind generation, grid stress has shifted from periods of peak gross load—historically driven by temperature—to periods of high net load, when demand remains elevated but renewable output has dropped. This transition has meaningfully changed which building measures deliver the greatest system value, elevating the importance of measures that reduce loads during evening and overnight hours over those that primarily target summer afternoon peaks.

This paper examines how LSC factors are evolving in response to future grid dynamics, using the 2028 California Building Energy Efficiency Standards as a case study. We find that critical hours are increasingly concentrated in winter months, when prolonged periods of low renewable output leave the grid with limited ability to replenish storage reserves. This pattern runs counter to building design practice still oriented around summer peak cooling loads. Expanding battery storage is flattening the LSC curve, converting the few extreme-cost hours that once drove measure selection into a broader band of moderately elevated costs. Together, these findings suggest that designing buildings for tomorrow's grid requires revisiting assumptions embedded in today's practice.

Introduction

California's Building Energy Efficiency Standards set minimum performance requirements for new construction and major renovations across the state, encompassing both mandatory energy efficiency requirements under the Energy Code (Title 24, Part 6) and voluntary standards under CALGreen (Title 24, Part 11). Together, these standards serve to reduce wasteful and unnecessary energy consumption while ensuring that buildings are designed to perform efficiently over their full operating lifetimes. California law requires that all changes to the Energy Code be cost-effective, and that cost-effectiveness be evaluated by amortizing the value of energy savings over the economic life of the structure. (CEC 2025a) In practice, this means that every proposed measure is assessed over a 30-year period of analysis and evaluated incrementally against the latest adopted code. This evaluation captures the full lifecycle value of reduced energy consumption relative to current baseline practice.

To operationalize this requirement, the California Energy Commission (CEC) relies on the Long-Term System Cost (LSC) metrics for gas, electric and propane usage. A secondary metric, long-term marginal source energy, is developed to evaluate the energy and emission impacts of building measures. Both metrics are updated each code cycle to reflect evolving grid conditions, demand forecasts, and, for the 2028 code cycle, a new set of weather data files that incorporate projected climate impacts on building loads and system performance.

This paper examines how the electric LSC factors underlying the 2028 California Building Energy Efficiency Standards reflect the fundamental transformation of the electric grid. Over the 30-year horizon that the LSC methodology is designed to capture, California's electricity system will be reshaped by several major drivers: 1) significant build-out of renewable generation and energy storage required to meet the state's SB 100 clean electricity mandate and reliability targets, 2) widespread electrification of buildings and vehicles, and 3) escalating electric and gas retail rates. The sections that follow show how these forces are shifting which hours carry the greatest system value, why critical hours (i.e., hours when load reduction can help mitigate loss-of-load risks and provide reliability value) are migrating from summer afternoons toward winter evenings and overnight periods, and what this means for the building measures best positioned to deliver cost-effective performance across a building's full useful life. Taken together, these findings underscore a tension in contemporary code development: the buildings being designed and permitted today will operate primarily on a grid that looks very different from the one that shaped current practice.

All results shown below are for non-residential buildings. Due to Assembly Bill 130 enacted in June 2025, the 2028 updates to LSC and source energy methodology apply only to non-residential buildings. Residential buildings will continue to be evaluated using the 2025 cycle metrics.

Methodology

Electric Long-Term System Cost

The LSC is the cost-effectiveness metric at the foundation of the California Building Energy Efficiency Standards. This paper focuses on electric LSC, which reports values as lifecycle net present value dollars per kWh of electricity. LSC factors are designed to value energy savings differently depending on when they occur, reflecting the actual cost of supplying energy to the grid in each hour. Measures that perform better during periods of high system stress are valued more highly than those that do not, creating an incentive for building designers to optimize performance precisely when system costs are greatest.

Electric LSC factors represent the average present value of all electricity system costs, levelized across every hour of a 30-year analysis period. These costs span two broad categories: marginal cost components and revenue recovery adders. Marginal costs vary by hour and reflect the time-dependent cost of supplying electricity. Revenue recovery adders capture costs that must be recovered through retail rates but are not fully captured by marginal pricing signals alone. The final electric LSC output is an hourly stream of 30-year net present value costs for a representative meteorological year, differentiated across California's 16 climate zones. Table 1 describes all components of electric LSC.

Table 1. Components of Electric LSC

Component	Description
Generation Energy	Estimate of hourly marginal wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery.

Component	Description
Generation Capacity	The marginal cost of procuring generation capacity resources to meet resource adequacy requirements.
Cap-and-Trade Allowance	Cost of CARB's cap-and-trade emission allowances. This component is embedded in the marginal energy cost in the 2028 LSC.
Clean Energy Cost	The costs of procuring additional renewable resources to offset emissions from increased loads, in order to meet legislated electricity sector emissions intensity targets.
Ancillary Services	The marginal cost of providing system operations and reserves for electricity grid reliability.
System Losses	The costs associated with additional electricity generation to cover system losses.
T&D Capacity	The costs of expanding transmission and distribution capacity to meet customer peak loads.
GHG Emission Cost	The value of economic, environmental and social damage that result from greenhouse gas (GHG) emissions.
Revenue Recovery Adder	These costs do not change when electricity consumption changes. They include but are not limited to costs of maintaining existing infrastructure, customer service, metering, billing, wildfire mitigation, and other non-variable charges. These are spread over all hours to ensure the total LSC matches forecasted revenues that need to be recovered through retail rates.

Development of Electric LSC Factors

The development process of 2028 electric LSC begins with a demand forecast that projects electricity consumption from all sectors of the economy over the 30-year analysis horizon. E3 then uses RESOLVE, a proprietary capacity expansion model, to identify the least-cost, policy-compliant resource portfolio needed to meet forecasted loads from 2029 through 2058. The RESOLVE portfolio is required to satisfy all applicable California mandates, including SB 100, the Renewable Portfolio Standard, and mid-term reliability procurement requirements.

The operation of this resource portfolio is then simulated in PLEXOS, a production cost model that represents optimized system dispatch under day-ahead market assumptions. PLEXOS generates hourly marginal energy prices and marginal generator heat rates, which provide the temporal shape for the LSC energy component. A key advancement in the 2028 cycle is the Integrated Calculation, which jointly derives marginal generation capacity and clean energy costs. This approach better reflects the reality that a portfolio of resources often contributes to both system reliability and decarbonization goals.

Hourly loss-of-load probabilities from E3's RECAP reliability model are used to assign generation capacity costs to the specific hours where load reductions carry the greatest system value, referred to as critical hours. T&D costs are allocated separately, using customer-level load forecasts to identify the peak load conditions that drive network investment. Finally, a retail rate forecast derived from projected utility revenue requirements is used to compute the revenue recovery adder, ensuring that the total LSC captures all costs that consumers will ultimately bear through rates.

LSC Factors as a Window into California's Future Grid

LSCs Reflect a 30-Year Policy Horizon

The LSCs are grounded in long-term policy and economic drivers that shape how California's energy system will evolve over the 30-year lifetime of a building constructed today. While some of these changes are not yet visible in current grid conditions, the LSCs capture their present value, ensuring that building designs are evaluated against the grid they will actually operate on, not the grid of today.

A foundational policy driver is SB 100, which mandates that California's electricity come entirely from clean sources by 2045 (California Senate Bill 100 2018). California has already made remarkable progress toward this goal, with more than 60% of electricity now generated from fossil-free sources (CEC 2025b). Meeting the remaining gap will require substantial additional deployment of renewable generation and energy storage, fundamentally reshaping when and how electricity is available on the grid. A policy-compliant resource portfolio was developed as part of the LSC modeling. Figure 1 illustrates the scale of solar and storage integration anticipated over the LSC horizon.

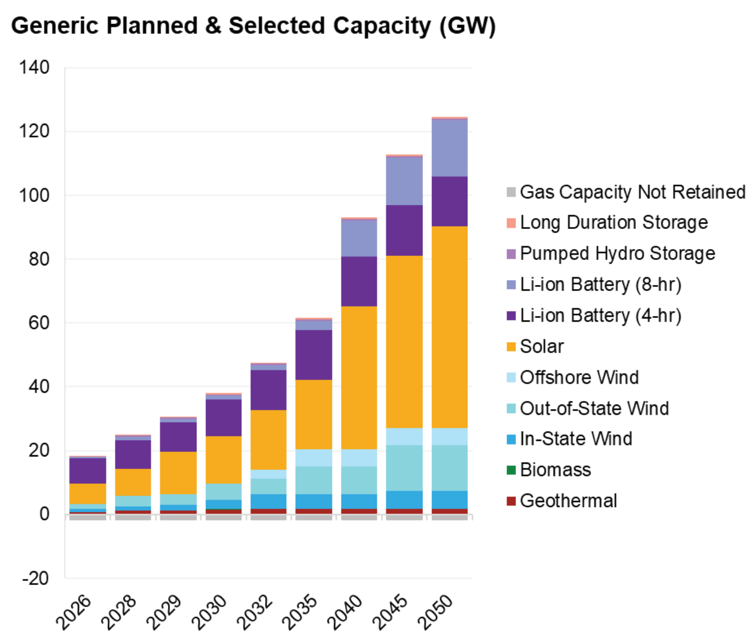

Figure 1. Selected resource portfolios as the basis for 2028 LSC capacity expansion model. Source: CEC 2025a.

Building and vehicle electrification will further transform both the electric and gas systems. This demand scenario behind 2028 LSCs is aligned with policy at the time of LSC development. As more homes and businesses switch from gas to electric appliances, natural gas throughput declines significantly, putting upward pressure on gas retail rates as fixed pipeline costs are recovered from a shrinking customer base. At the same time, widespread adoption of electric space heating will drive significant increases in winter electricity loads. On the transportation side, vehicle electrification will dramatically increase total electricity consumption, with EVs forecast to account for roughly one third of all electricity sales by 2050, as shown in Figure 2.

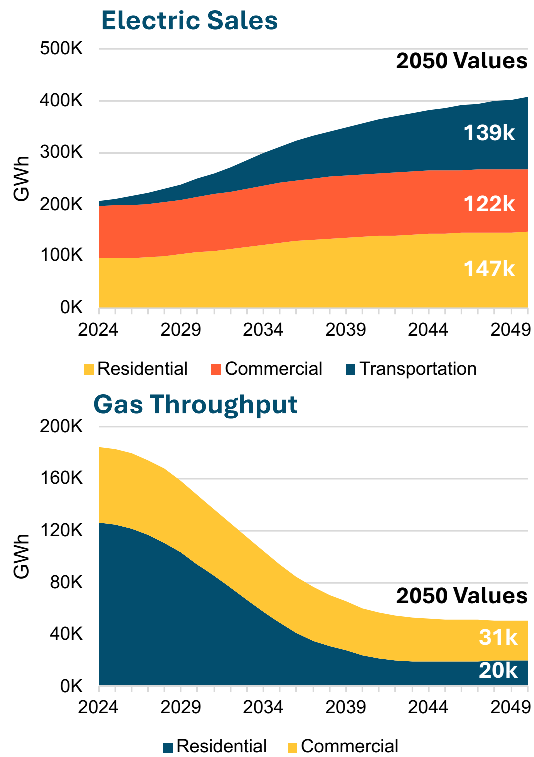

Figure 2. Forecasted electric sales and gas throughput in 2028 LSC. Source: CEC 2025a.

Finally, climate change will alter the conditions under which buildings operate throughout their lifetimes. LSC modeling is based on a Typical Meteorological Year (TMY) that represents average weather conditions. For the 2028 code cycle, a new set of TMY datasets were developed to reflect the impact of future climate. Figure 3 compares the TMY with future weather to a TMY with historical weather, for the month of July. On average, California can expect hotter summers and milder winters.

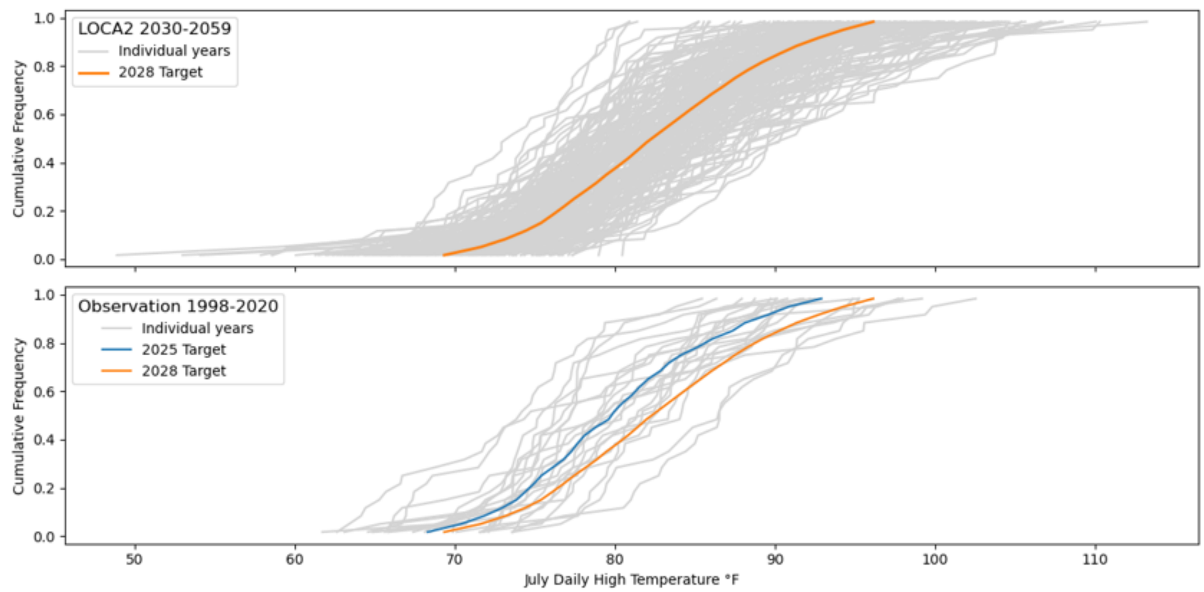

Figure 3. Temperature occurrence frequency in July for 2025 code cycle (2025 target) which was based on historical weather and for 2028 code cycle (2028 target) which is based on future weather. Source: CEC 2025c.

Because LSC factors are built on a 30-year forecast of system costs, they capture grid conditions that have not yet fully materialized but will define the operating environment for buildings permitted today. The sections that follow examine the key ways California's grid is changing and what those changes mean for which building measures deliver the greatest cost-effective performance over a building's lifetime. Table 2 summarizes these shifts and their implications before each is examined in detail.

Table 2. Paradigm Shifts in California's Future Grid and Implications for Building Measure Cost-Effectiveness

Grid Paradigm Shift	Measures That Benefit the Grid Today	Measures That Benefit the Grid in the Future
Rising retail rates	Only the least expensive efficiency measures clear the cost-effectiveness threshold	Expensive shell and HVAC improvements that save significant energy particularly during high-cost hours could deliver returns that justify their first costs
From gross load to net load as the driver of grid stress	Measures that reduce cooling load during hot summer days, when temperature-driven demand peaks	Measures that reduce demand during evening hours when solar output drops and net load is elevated
From summer to winter as the season of critical hours	Measures that reduce summer cooling loads, particularly in hotter inland climate zones	Measures that reduce winter heating loads and overnight demand during renewable drought periods, particularly all-electric shell improvements

Grid Paradigm Shift	Measures That Benefit the Grid Today	Measures That Benefit the Grid in the Future
LSC curve flattening with high storage penetration	Measures that save energy a few hours a year	Measures with broad savings across many hours; load shifting that moves demand into solar-abundant midday windows when storage is charging

Forecasted Electric and Gas Retail Rates Continue to Increase

California has some of the highest retail electricity rates in the country, and those rates are projected to continue rising above inflation for the foreseeable future. The primary drivers of California's high and rising electric rates include wildfire-related costs, rooftop solar program cost shifts, and increased investment in distribution infrastructure (CPUC 2025). Wildfire-related costs alone have grown from a negligible share of IOU rates prior to 2019 to between 7% and 13% of average non-CARE bills today. Beyond wildfire costs, distribution system costs excluding wildfire have risen at an annual average rate of approximately 11% since 2019 (CPUC 2025). Additionally, growth in net metered behind-the-meter solar has been associated with higher retail prices for the broader customer base, as fixed grid costs are shifted onto non-participating customers when solar adopters reduce their volumetric contributions to system cost recovery.

The LSCs reflect forecasted revenue requirements and electric sales, and project that electric rates will continue to rise above inflation into the future. Forecasted revenue requirements represent the total amount a utility must collect from customers to cover all prudently incurred costs over the planning horizon. Forecasted electric sales reflect significant building and vehicle electrification consistent with California's decarbonization goals.

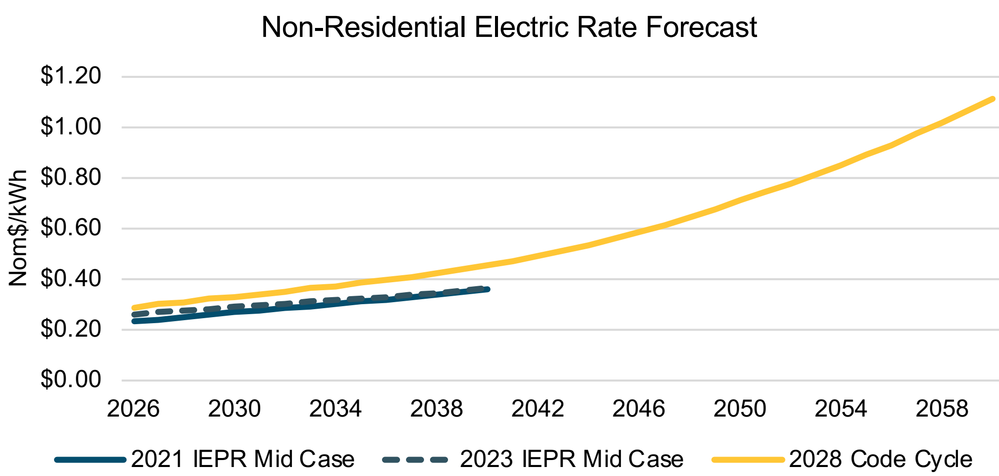

Figure 4. Non-residential electric rate forecast. Source: CEC 2025a.

On the gas side, while retail rates in California are moderate today, they face significant upward pressure over the 30-year LSC horizon. As more homes and businesses electrify, gas throughput declines while the fixed costs of maintaining the gas distribution system remain largely unchanged. These fixed costs must then be recovered from a shrinking base of remaining customers, creating the well-documented risk of a utility "death spiral" in which rising rates accelerate further departures from the gas system, driving rates higher still. Low-income households and renters, who face greater barriers to adopting electric alternatives, are especially exposed to this dynamic. This pressure is further compounded by the fact that California's combined gas utility revenue requirements have already been rising steadily, driven by infrastructure replacement costs for aging and leak-prone pipelines that must be addressed for safety reasons.

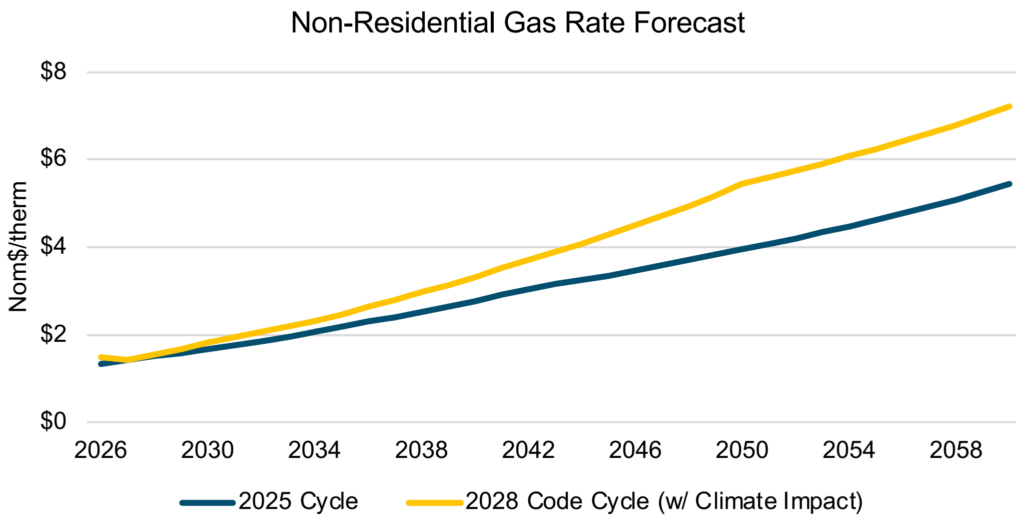

Figure 5. Non-residential gas rate forecast. Source: CEC 2025a.

The combined trajectory of high and rising electric rates and escalating gas rates has important implications for the cost-effectiveness of building measures. Higher rates translate directly into higher lifecycle bill savings for any measure that reduces energy consumption, expanding the universe of measures that clear the cost-effectiveness threshold. Measures with higher upfront costs, such as building shell improvements or high-efficiency HVAC equipment, may become more cost-effective under a high-rate trajectory, as the same stream of energy savings is worth considerably more in present value terms. Because the LSCs are grounded in lifecycle system cost savings rather than first-year bill savings or simple payback, this dynamic is fully captured in the cost-effectiveness framework. As the following sections show, the value of those savings depends not only on their magnitude but increasingly on their timing and that timing is shifting as California's grid evolves.

LSCs Are More Correlated to Net Load than Temperature

Traditionally, generation-related costs were highest when total system demand, often referred to as "gross load," was at its peak. This reflected the paradigm that the grid is the most constrained when the customer load is the highest, which is heavily depends on temperature. In the traditional electric system, the vast majority of generating resources were thermal powered by fossil fuels, and could be considered "firm," meaning they were able to produce power at full capacity at any time for sustained periods, barring maintenance or forced outage. Because most resources were available at any given time, the periods of highest reliability risk coincided with periods of peak load, when demand could approach or exceed the aggregate capability of all generating resources. As a result, the cost of electricity and grid reliability risk were largely determined by when high temperatures drove cooling loads and total customer demand to its highest levels (Figure 6).

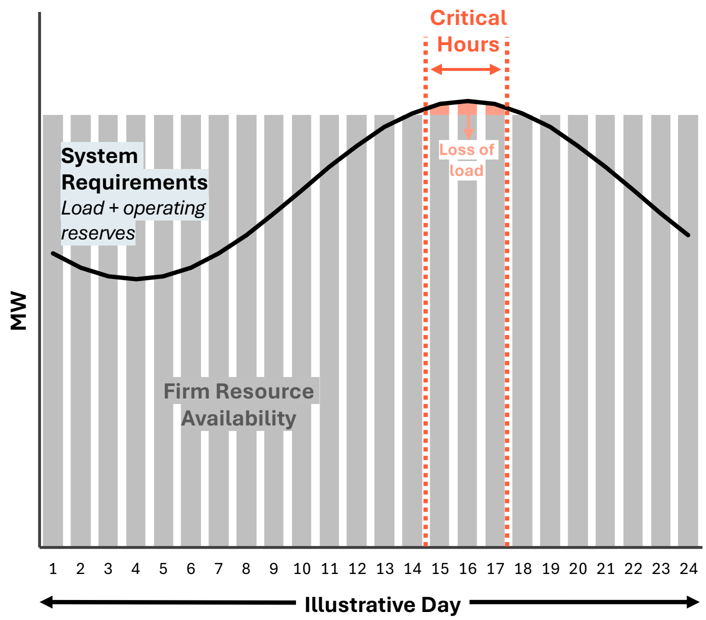

Figure 6. Illustrative figure to show that in traditional power systems, critical hours almost always coincided with highest demands. Source: E3 2025.

As California has incorporated increasing shares of wind, solar, and other variable renewable generation, a fundamental shift has emerged. The time of day when gross load is highest no longer necessarily places the greatest pressure on the electric grid. Instead, the most critical periods are those when load remains elevated but renewable generation has dropped, leaving the grid with less clean capacity to meet demand. This concept is captured by "net load," defined as total customer demand minus variable renewable generation, which has become the more meaningful indicator of grid stress in a high-renewables system, as illustrated in Figure 7.

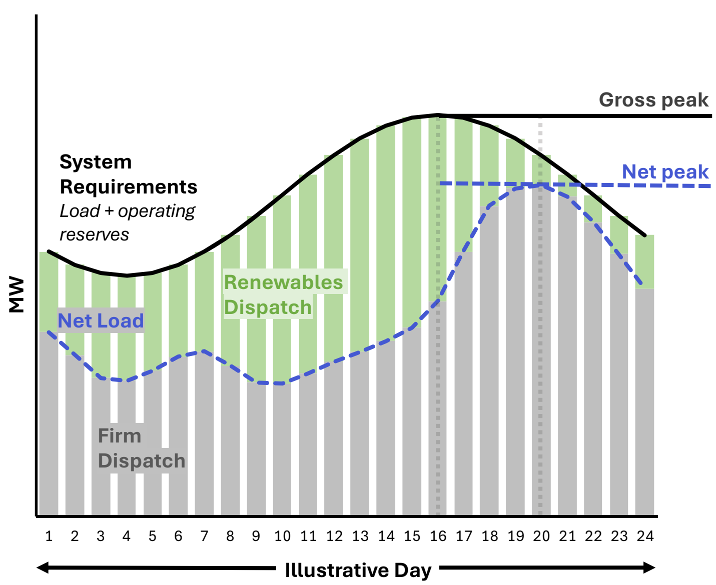

Figure 7. Illustrative figure to show that in a system with high renewable penetration, critical hours occur around net peaks rather than gross peaks. Source: E3 2025.

A clear illustration of this shift occurred in September 2022, when the California Independent System Operator (CAISO) issued a Flex Alert to request energy conservations from all customers between 4:00 pm and 9:00 pm. While the gross load peaked around 4:55 pm, the Governor's Office of Emergency Services issued an emergency alert at 5:45 pm, asking residents to conserve power until 9 pm (Brown 2022). This was the time when load was still high but solar output had dropped to near zero. Similar patterns can be observed in the rolling outages in August 2020 and near miss events in September 2024. Together, these events mark a fundamental transition in California's grid risk profile: the period of greatest reliability risk is no longer defined by when load is highest, but by when the grid's capacity to serve that load is most constrained, typically after sundown and increasingly later in the cooling season as the solar day shortens.

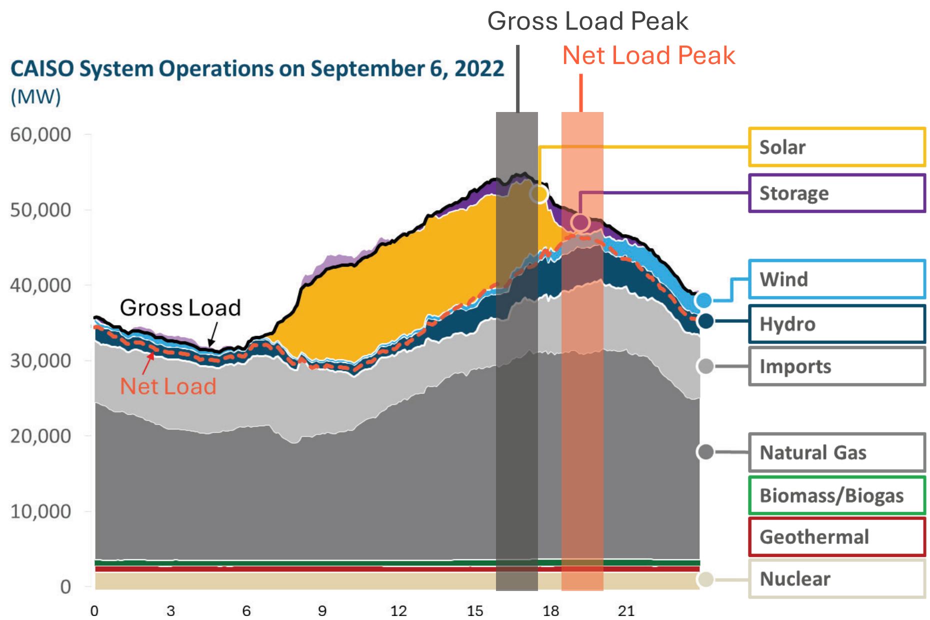

Figure 8. CAISO system operations on September 6, 2022. Source: CEC 2025a.

The 2028 LSC factors reflect this transition directly. As shown in Figure 9, energy-related marginal costs are now more strongly correlated with net load than with heating or cooling degree days. The figure shows CZ9 as an example but similar patterns can be observed in other climate zones. One important nuance is that transmission and distribution (T&D) costs follow a different pattern.

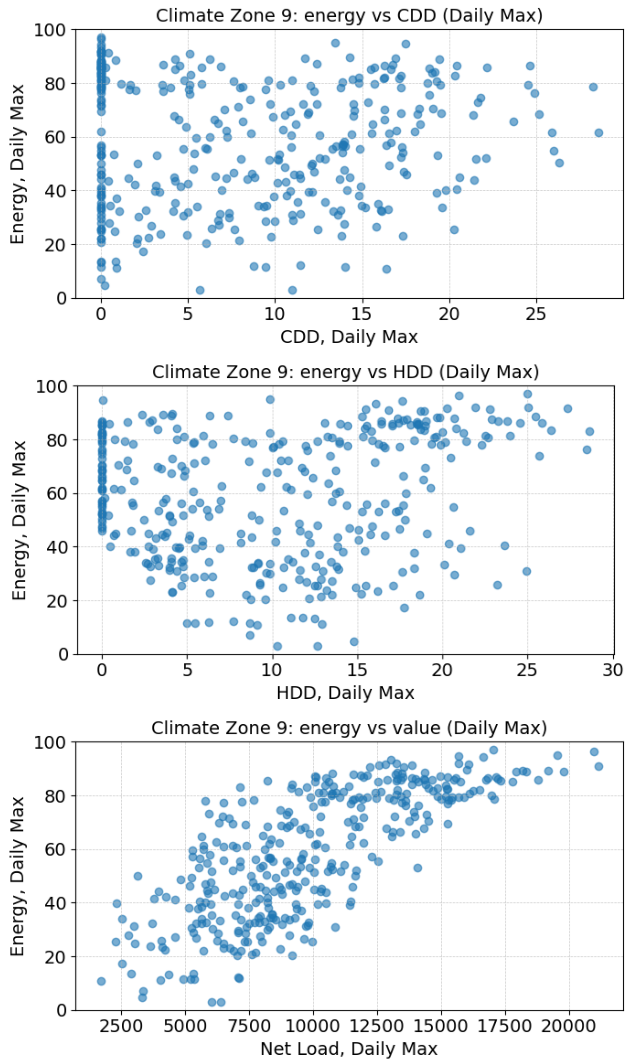

Figure 9. Correlation between marginal energy prices and Cooling Degree Days, Heating Degree Days and Net Load for 2028 LSC. Source: CEC 2025a.

Taken together, these dynamics mean that measures that reduce or shift load during net peak hours, particularly during evening and overnight periods, will become more important, while the premium on summer afternoon peak reduction is moderated, though not eliminated. Load reduction during solar-abundant midday hours similarly loses relative value as increasing renewable generation suppresses marginal costs during those periods. Rooftop solar, once among the most consistently valuable distributed energy resources, becomes less valuable on its own in this context, as its output peaks precisely when the grid needs it least. Pairing solar with battery storage that cycles daily restores much of that value by allowing buildings to capture midday generation and discharge it during the evening net peak when system costs are highest.

Broadly, technologies and design strategies that enable buildings to reduce their draw on the grid after sundown are well-positioned under this framework. This includes high-performance envelopes with significant thermal mass, pre-conditioning strategies enabled by smart controls, and flexible end uses such as water heating and space conditioning that can shift consumption without compromising occupant comfort. Smart EV charging that avoids evening hours and takes advantage of low-cost midday solar similarly aligns well with the evolving LSC signal, as does distributed battery storage that can be dispatched in response to time-varying grid costs.

Because T&D infrastructure has fixed physical capacity that does not respond to changes in the generation mix, the hours when T&D costs are highest remain correlated with total system demand rather than net load. Building measures capable of reducing gross peak demand, such as efficient cooling systems and envelope improvements that limit summer heat gain, therefore still retain meaningful value for avoided T&D investment.

Critical hours shift from summer to winter

California's electric grid has historically experienced the greatest stress and highest LSCs during the summer months. This was largely due to the major electricity demand from air conditioning during hot weather. As mentioned in the previous section, currently grid constrained periods have moved from summer gross peaks to summer net peaks. As the grid shifts toward an even higher share of renewable electricity to meet the state's SB100 goals, and with a future that includes high electrification of buildings and vehicles, the pattern of grid stress periods will continue to increasingly occur during winter months.

Winter poses a distinct reliability challenge due to prolonged periods of low renewable output during which limited generation prevents storage from fully recharging. These renewable droughts, which may last for days, leave the system with few options to meet demand, representing the periods of greatest grid stress. As illustrated in Figure 10, while solar generation meets or exceeds system demand for most weeks of the year, a winter week under cold weather conditions can expose repeated episodes where solar output significantly reduces and storage is exhausted. These are the periods when reducing building loads is most valuable, as every kilowatt-hour avoided displaces generation from the most expensive and carbon-intensive resources on the grid.

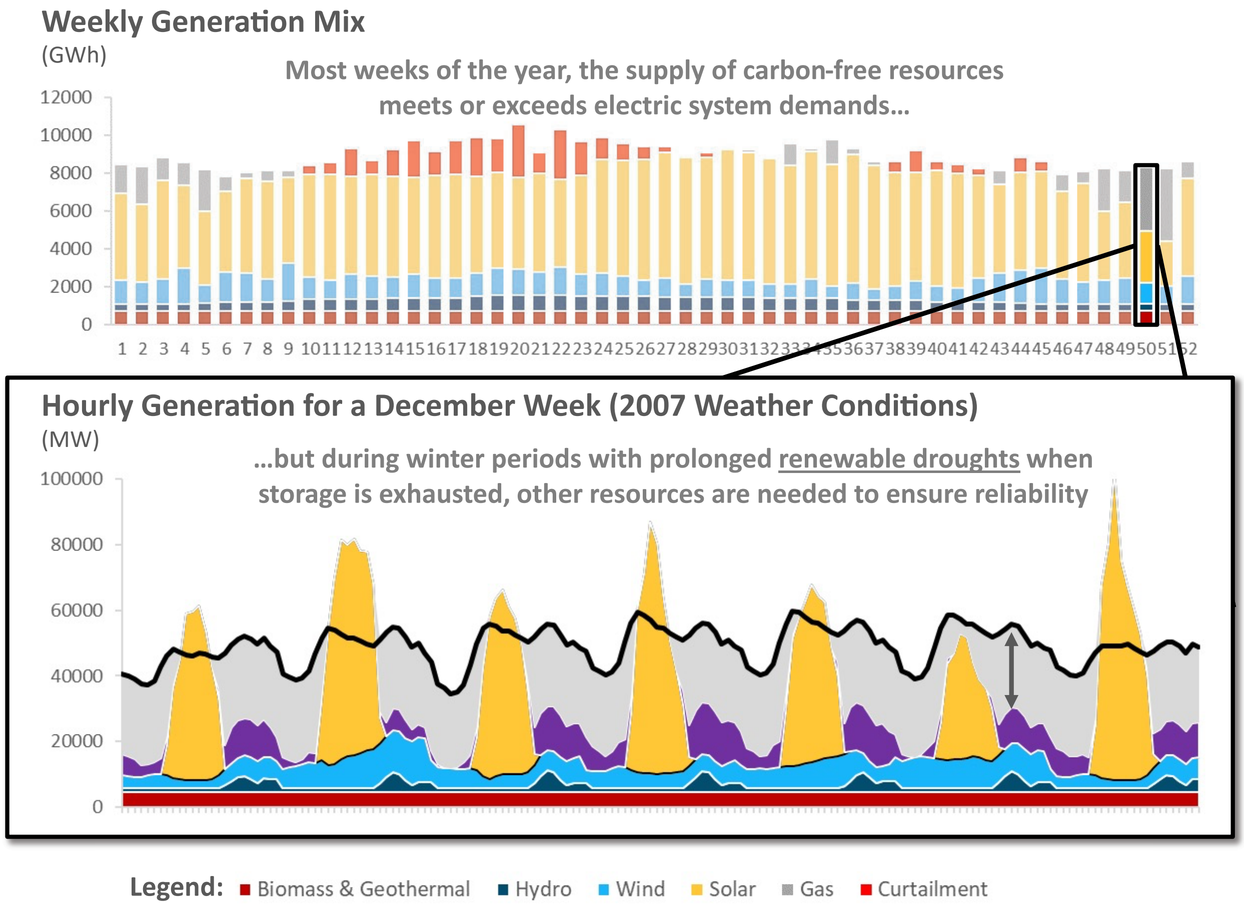

Figure 10. Simulated system operations show that winter weeks are time when solar generation is much lower and therefore the system needs other resources. Source: E3.

As shown in Figure 11, the distribution of critical hours, which mark the hours load reduction is the most valuable to help reduce loss-of-load events (i.e., grid outages), will mainly concentrate in the winter by 2045. While the highest single-day loads in California still typically occur in the summer, the 30-year average LSC data reveals a growing number of high-cost hours in the winter. This shift reflects the growing difficulty and cost of serving load under conditions of low renewable generation and high electricity demand.

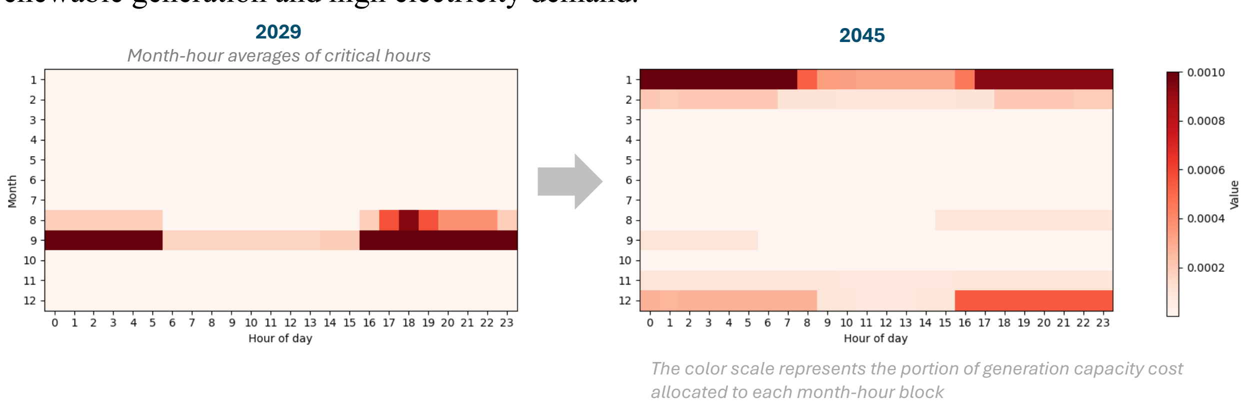

Figure 11. Month-hour averages of critical hours in 2028 LSC. Source: CEC 2025a.

This transition of high-cost hours to winter runs counter to current building design practice, which remains focused on reducing peak cooling loads in summer. This misalignment highlights a tension: the measures that optimize a building's performance for today's grid conditions are not necessarily those that will deliver the greatest value under future grid conditions. The measures best suited to address these emerging winter critical hours are those that reduce heating needs across many consecutive hours, including overnight. These include:

- **Improved envelope performance** (air-tightness and insulation), to reduce the rate at which buildings lose heat.
- **Increased thermal mass**, to help buildings retain heat and coast through nighttime hours without active heating.
- **High solar heat gain glazing paired with exterior shading**, which allows passive solar gains to offset heating loads in winter while blocking unwanted solar heat gain in summer—a reversal of the low solar heat gain approach that has historically been preferred in California.

LSCs are Getting Flatter with Higher Storage Penetration

California has deployed more than 15GW of energy storage (CEC 2025d). These batteries cycle daily, shifting surplus midday renewable generation to the evening hours and serving resource adequacy needs during the net peak. As shown in Figure 12, battery dispatch during CAISO peak days was nearly zero in 2020 but jumped to 8.7 GW by 2025. Energy storage acts as a flexible resource, charging when electricity is abundant and discharging during periods of higher demand. As more storage is integrated into the grid, it smooths sharp demand peaks and reduces the need for expensive, high-marginal-cost generation during critical hours.

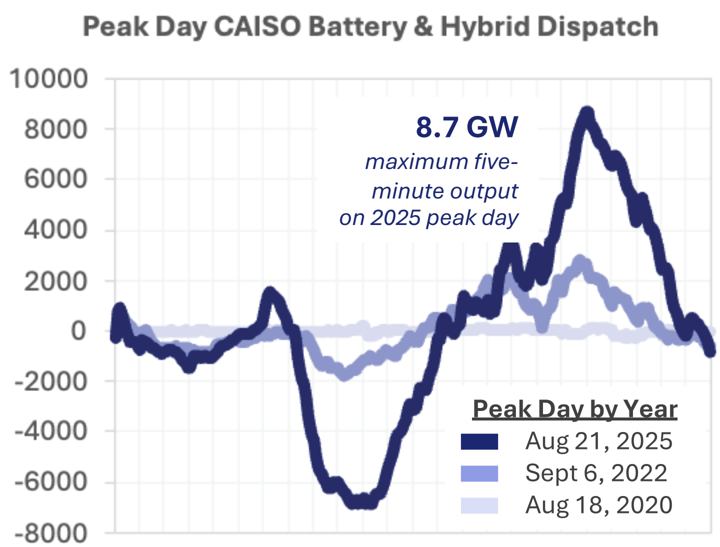

Figure 12. CAISO Battery dispatch on peek days in 2020, 2022 and 2025. Source: E3.

LSC metrics reflect a similar evolution across recent code cycles. As shown in Figure 13, compared to the 2022 code cycle, the highest LSC values in the 2025 cycle are meaningfully lower, reflecting the fact that a grid with large amounts of flexible storage will experience fewer hours of extreme cost because storage can be dispatched at virtually any hour in response to grid conditions.

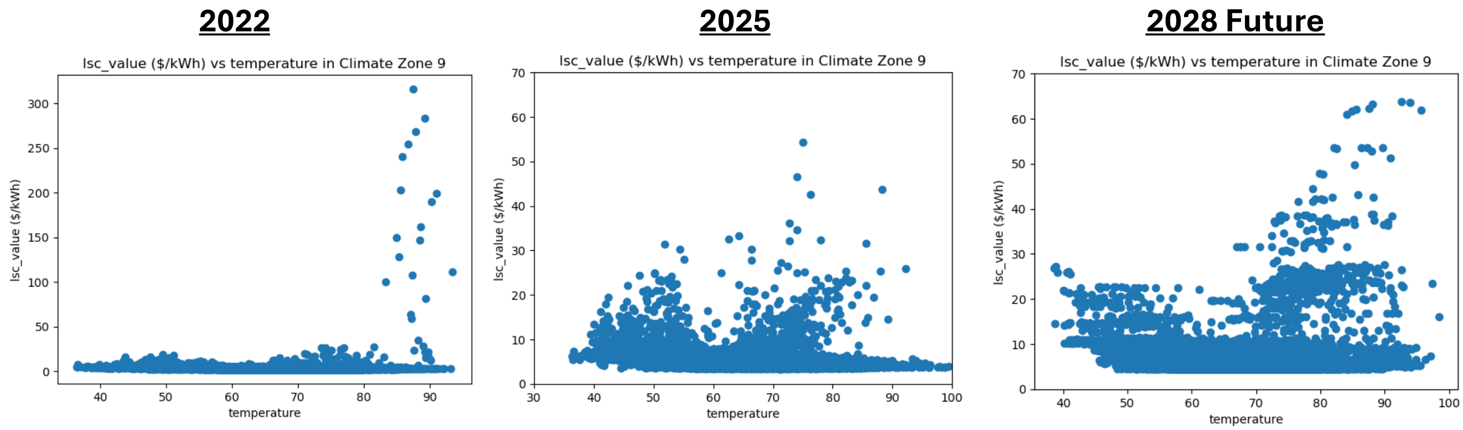

Figure 13. Hourly LSCs vs temperature for 2022, 2025 and 2028 code cycles. Note that the y-axis scale is different between the 2022 cycle and the other two cycles. Source: CEC 2025a.

The flattening of the LSC curve represents a fundamental shift in how building measures should be evaluated. Under earlier code cycles, cost-effectiveness was heavily influenced by performance during a relatively small number of extreme hours, which mostly occurred in summer afternoon peaks when marginal costs spiked sharply above the baseline. In that paradigm, measures capable of shedding load during those few critical hours carried outsized value, while performance during the remaining hours mattered less. A new paradigm emerges with high storage penetration: there are now many hours of moderately elevated system cost rather than a few hours of very high cost. The practical implication is that measures delivering consistent, daily load shifting become more valuable relative to those optimized for occasional demand response during extreme events.

As the grid becomes increasingly saturated with solar and storage, the measures that deliver greater value are those that can shift load from nighttime into daytime hours on a regular basis. Envelope improvements and thermal mass remain valuable in this context, passively reducing heating loads during winter days. Complementing these passive strategies, heat pump water heaters with demand flexibility can be programmed to charge during midday solar surplus hours, reducing grid draws during evening and overnight periods. Similarly, pre-cooling and pre-heating strategies enabled by smart thermostats allow buildings to use low-cost daytime electricity to condition spaces in advance, reducing demand during evening hours when storage resources are most stretched. Smart EV charging that avoids evening hours and captures midday solar follows the same logic, as does battery storage that can be dispatched in response to time-varying costs throughout the day.

Conclusions

This paper examined four shifts: rising retail rates, the transition from gross to net load as the driver of grid stress, the migration of critical hours toward winter, and the flattening of the LSC curve with growing storage penetration. These shifts are mutually reinforcing features of the same underlying transformation. A grid increasingly dominated by solar and storage is one where the marginal value of energy is low at midday and elevated in the evening and overnight, where winter renewable droughts impose the most severe reliability constraints, and where the cost of serving load is recovered through rates that will continue to climb as gas customers exit and electric infrastructure investment accelerates. The LSC methodology is designed to capture this compounding complexity, translating a 30-year trajectory of grid and rate evolution into the hourly cost signals that determine which building measures are worth building to.

The practical implication for code development is that the buildings permitted under the 2028 standards will spend most of their useful lives on a grid that looks substantially different from today's. Measures that deliver reliable load reduction across many hours, particularly during winter evenings and overnight periods, are better positioned under this framework than those optimized for a few summer afternoon peaks. High-performance envelopes and thermal mass, which reduce heating loads passively and continuously, gain value both from the seasonal shift in critical hours and from the flattening of the LSC curve that rewards consistent performance over peak-hour shedding. Heat pump water heaters with demand flexibility, smart HVAC controls capable of pre-conditioning, and storage-paired solar all align well with a cost structure that increasingly favors load shifted into the solar-abundant midday window. California's code development process has long required that buildings be evaluated against the grid they will actually operate on, not the grid of today. The 2028 LSC factors reflect the rigor of that commitment and the urgency of getting the design assumptions right.

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AI Disclosure

AI-assisted tools used: Claude
Used for: brainstorming, draft editing, citation and figures formatting
Extent: light editing / drafting sections
Human review: The authors reviewed and verified all content, calculations, and citations.