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Metrics for Developing Building Energy Efficiency Standards

2028 Energy Code Metrics Methodology and Results

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Energy+Environmental Economics

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IV. Acronym Definitions

Acronym	Definition
ACC	Avoided Cost Calculator
AS	Ancillary Services
CARB	California Air Resources Board
CBECC	California Building Energy Code Compliance
CDD	Cooling Degree Day
CEC	California Energy Commission
CPUC	California Public Utilities Commission
EPA	Environmental Protection Agency
EV	Electric Vehicle
GHG	Greenhouse Gas
HDD	Heating Degree Day
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
LOLP	Loss-of-Load Probabilities
LSC	Long-Term System Cost
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
PCT	Participant Cost TRest
RECC	Real Economic Carrying Charge
RPS	Renewable Portfolio Standard
SB	Senate Bill
TDV	Time Dependent Valuation
TMY	Typical Meteorological Year
TOU	Time of Use
TRC	Total Resource Cost
T&D	Transmission & Distribution
T&S	Transmission & Storage

I. Introduction and Context

Introduction

California's Building Energy Efficiency Standards include building energy efficiency requirements in the Energy Code (Title 24, Part 6) and voluntary building energy efficiency standards in CALGreen (Title 24, Part 11). Together these serve to reduce wasteful, uneconomic, inefficient, and unnecessary consumption of energy in the state. California Law requires the Building Energy Efficiency Standards be cost-effective. Moreover, cost-effectiveness must consider the value of energy when "…amortized over the economic life of the structure compared with historic practice". This means all measures are assessed over a period of analysis of 30 years, and that both the benefits and the costs are assessed incrementally – meaning in comparison to the latest adopted version of the Energy Code.

To evaluate the cost-effectiveness of energy efficiency measures, the Long-Term System Cost (LSC) metric is utilized. Additionally, a long-term, marginal hourly source energy metric is used to evaluate the source energy savings of energy efficiency measures, which correlates strongly with statewide marginal greenhouse gas (GHG) emissions. Updates to these metrics are based on updated weather data, which is described in the memo titled "Weather Data File Updates for the 2028 Energy Code," https://efiling.energy.ca.gov/GetDocument.aspx?tn=265692&DocumentContentId=102543.

This report documents the major changes in LSC factors and source energy factors from the 2025 to 2028 code cycle, and the associated changes in methodology to compute the 2028 metrics[1]. This report also presents a detailed look at the changing California electricity grid, and how these changes are creating a paradigm shift in what we should expect LSC factors and source energy factors to look like moving forward.

The forthcoming 2028 update to the LSC and source energy methodology will only apply to nonresidential building types. All results in this report reflect changes to nonresidential metrics only.

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[1] Wichert, RJ and Will Vicent. 2024. 2025 Energy Code Accounting Methodology Staff Report. California Energy Commission. Publication Number: CEC-400-2024-004

History and Principles of Metrics

Prior to 2005, the value of energy efficiency measure savings had been calculated based on a “flat” system average source energy. Since the 2025 code cycle, a cost-effectiveness metric, called Long-Term System Cost (LSC), has been used as the foundation of the Building Energy Efficiency Standards. LSC replaced the previous Time Dependent Valuation (TDV) metric and reports values as lifecycle net present value $/kWh and $/therm. LSC factors represent a long-run forecast of system costs that includes higher costs when the system is expected to be constrained.

In the 2022 code cycle, a long-run hourly source energy metric was introduced as a second performance metric to complement the LSC cost-effectiveness metric, and this will continue in the 2028 cycle. The hourly source energy metric for electricity reflects the marginal source energy of fossil fuels that are combusted as a result of building energy consumption either directly at the building site or caused to be consumed to meet the electrical demand of the building considering the long-term effects of changes in Commission-projected energy resource procurement to meet future energy demand. The hourly source energy helps ensure alignment with the state’s goal to reduce greenhouse gas emissions aggressively from the building sector, since it strongly correlates with statewide greenhouse gas emissions.

In the 2028 cycle, LSC will remain as the basis of cost-effectiveness calculations for proposed building designs. In addition to LSC, the Energy Code will continue to use both LSC and Source Energy for showing compliance with the performance standards.

LSC and source energy metrics are designed to value energy efficiency measure savings differently depending on when savings occur, to better reflect the actual costs of energy and the intensity of source energy to consumers and to the utility system in that hour. This means that energy efficiency measures that perform better during times of high energy cost are valued more highly than measures that do not, and encourages building designers to design buildings that perform better during these periods.

Electric LSC factors represent the average present value of all electricity system costs, levelized across every hour over a 30-year analysis period. This analysis requires forecasting electricity demand from all sectors of the economy that will rely on the grid during this timeframe. It identifies projected growth in grid service needs and evaluates the future resources that must be added—on an hourly basis—to meet evolving demand at the lowest total cost.

In addition to the costs to develop new resources, LSCs incorporate all projected expenses necessary to maintain the electric grid's reliability and support other customer programs and services over the 30 years. The sum of these expenses represents the total revenue requirement, which is the amount of money that must be collected from electricity customers to cover all system costs. When averaged over all hours of the study period, these costs represent the forecasted average rates that customers will need to pay over the economic life of buildings subject to the Energy Code.

The hourly electric cost effectiveness factors are correlated with the statewide typical weather files used in building simulation tools[2]. The underlying renewable generation and wholesale electric grid operations modeled to develop the Energy Code metrics are aligned with the statewide typical weather files. This alignment is critical because, as the grid integrates more renewable resources, both electricity demand and renewable output influence grid operations, and by extension, the LSC and source energy values. Historically, the grid was most constrained during periods of peak electricity demand—typically hot summer afternoons. However, looking ahead as the state increases renewable generation on the way to 100% by 2045 under SB100, as well as energy storage, the most constrained periods will shift to periods when electricity demand is high and renewable generation is low. These conditions can arise during winter cold snaps with low solar and wind output, or on summer days when solar generation alone cannot meet demand and storage has not charged sufficiently, making demand reduction and flexible load especially valuable.

Table 1 lists all components of the electric LSC, while Table 2 lists all components of the gas LSC. Additional details on the principles of the LSC metrics, as well as answers to frequently asked questions, can be found in the Appendix. The total of all of the components determine the revenue requirements for the statewide utility systems that must be recovered through rates.

[2] Updated weather data is described in the memo titled "Weather Data File Updates for the 2028 Energy Code," https://efiling.energy.ca.gov/GetDocument.aspx?tn=265692&DocumentContentId=102543.

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.
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 (previously called GHG Adder)	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 (previously called Emission Abatement Cost)	The value of economic, environmental and social damage that result from greenhouse gas (GHG) emissions.
Revenue Recovery Adder (previously called Retail 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.

Table 2. Components of Gas LSC

Component	Description
Commodity Cost	The wholesale cost of natural gas.
T&S (previously T&D)	Transmission and storage system costs.
Cap-and-Trade Allowance	The cost of CARB's cap-and-trade emission allowances.
Clean Energy Cost (previously part of Commodity Cost)	The cost of blending in biogas or hydrogen, based on policy requirements.
Methane Leakage	The climate-related cost associated with methane emissions that escape during production, transmission, and use of natural gas.
GHG Emission Cost (previously called Emission Abatement Cost)	The value of economic, environmental and social damage that result from the greenhouse gas (GHG) emissions.
Revenue Recovery Adder (previously called Retail Adder)	These costs do not change when gas use changes. They include but are not limited to costs of maintaining existing infrastructure, customer service, metering, billing 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.

II. Updates to 2028 Metrics Inputs & Methodology

This section summarizes the key changes to the 2028 LSC methodology compared to the 2025 approach. The 2025 approach is summarized in the 2025 Energy Code Accounting Methodology Report.[3]

2028 Electric LSC Modeling Overview

While the Long-term System Cost (LSC) metric applies to electricity, propane, and gas, developing the electric LSC is particularly complex. The final output is an hourly stream of 30-year net present value (NPV) costs for a typical meteorological year that is representative of the weather over the economic life of buildings subject to the Energy Code, for each of California's diverse climate zones. These hourly values represent the combined, time-variant costs of supplying electricity to meet forecasted systemwide demand, that is updated for each code cycle. The development of electric LSC involves integrating hourly cost streams from each of the components and encompasses the following modeling steps:

+ **Capacity Expansion Modeling (RESOLVE):** To derive 30-year marginal costs for energy, capacity, and clean energy, a policy-compliant resource portfolio must first be developed to

[3] Report link: https://efiling.energy.ca.gov/GetDocument.aspx?tn=255318-1&DocumentContentId=91004

meet the forecasted loads over the 30-year period. E3 uses RESOLVE, its proprietary capacity expansion model, to determine an optimal generation mix for the period 2029 through 2058, starting with the existing grid resources. RESOLVE has also been used to define resource plans for load serving entities in the CPUC's Integrated Resources Planning (IRP) proceeding. The resource portfolio developed for the 2028 LSC is compliant with all policies in California, including SB100, the Renewable Portfolio Standard (RPS), and Mid-Term Reliability Procurement mandates.

+ **Production Cost Simulation (PLEXOS):** The operation of the resource portfolio developed in RESOLVE is then simulated in PLEXOS, a production cost model that represents optimized system dispatch under day-ahead market assumptions. PLEXOS is used to generate hourly values such as marginal energy prices and marginal generator heat rates.[4] These values provide the temporal shape for LSC and are adjusted to reflect cap-and-trade allowance costs and system losses. These values are also used in determining the electricity hourly source energy factors.
+ **Integrated Calculation of Capacity and Clean Energy Costs:** A key advancement in the 2028 cycle is the Integrated Calculation, which jointly derives marginal generation capacity and clean energy costs on an annual basis. This approach replaces the prior practice of calculating these costs separately, recognizing that the same portfolio of resources often contribute to both system reliability and decarbonization goals. A detailed explanation of this methodology is provided in the Appendix.
+ **Reliability Modeling (RECAP):** While annual capacity values are produced in the Integrated Calculation, the assignment of these values to specific hours is derived through E3's RECAP model. RECAP calculates hourly loss-of-load probabilities[5] (LOLP) using the assumed resource portfolio, load profiles, and resource availability. These LOLP-based hourly factors assign generation capacity costs to hours in which load reduction is valuable to help improve system reliability. The 2028 LSC has redefined critical peak hours in terms of LOLP, and the detailed methodology is discussed in the Refinement of Capacity Cost Allocation Factors section.
+ **Transmission & Distribution (T&D) Modeling:** T&D capacity costs are estimated in two parts: 1) Annual costs that are provided by the IOUs, and 2) hourly allocation that is developed through the following steps:

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[4] Marginal generator's heat rate measures how efficiently a generator converts fuel into electricity, expressed in British thermal units (Btu) per kilowatt-hour (kWh). The lower the heat rate, the greater the efficiency.

[5] Loss of Load Probability (LOLP) is a reliability metric in power systems that represents the likelihood that a system's available generation capacity will be insufficient to meet the demand from electric loads on the system.

    - Load shapes are constructed by combining forecasted building and other customer sector end uses (e.g., cooling, heating, EV) and subtracting customer-side solar generation.

- The resulting customer load is mapped to typical meteorological year (TMY) weather data by climate zone.
    - The 350 hours with the highest customer demand are selected as allocation hours for increases in T&D costs; all other hours are set to zero. This reflects the principle that distribution and transmission upgrades are driven by localized peak load conditions.

- **Retail Rate Modeling:** To complete the LSC calculation, the revenue recovery adder is calculated. This adder represents the costs that do not change when electricity load 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 includes all costs included in revenue requirements that will be required to be recovered through retail rates. Determining the revenue recovery adder requires forecasting future average retail rates. As such, E3 develops a 30-year retail rate forecast using projected utility revenue requirements and load forecasts. Including these costs ensures that the total LSC captures all costs that must be recovered in consumer electricity bills, while preserving the underlying time-dependent marginal price signals. The detailed methodology can be found in the Appendix.

Figure 1. Modeling Framework of 2028 Electric LSC

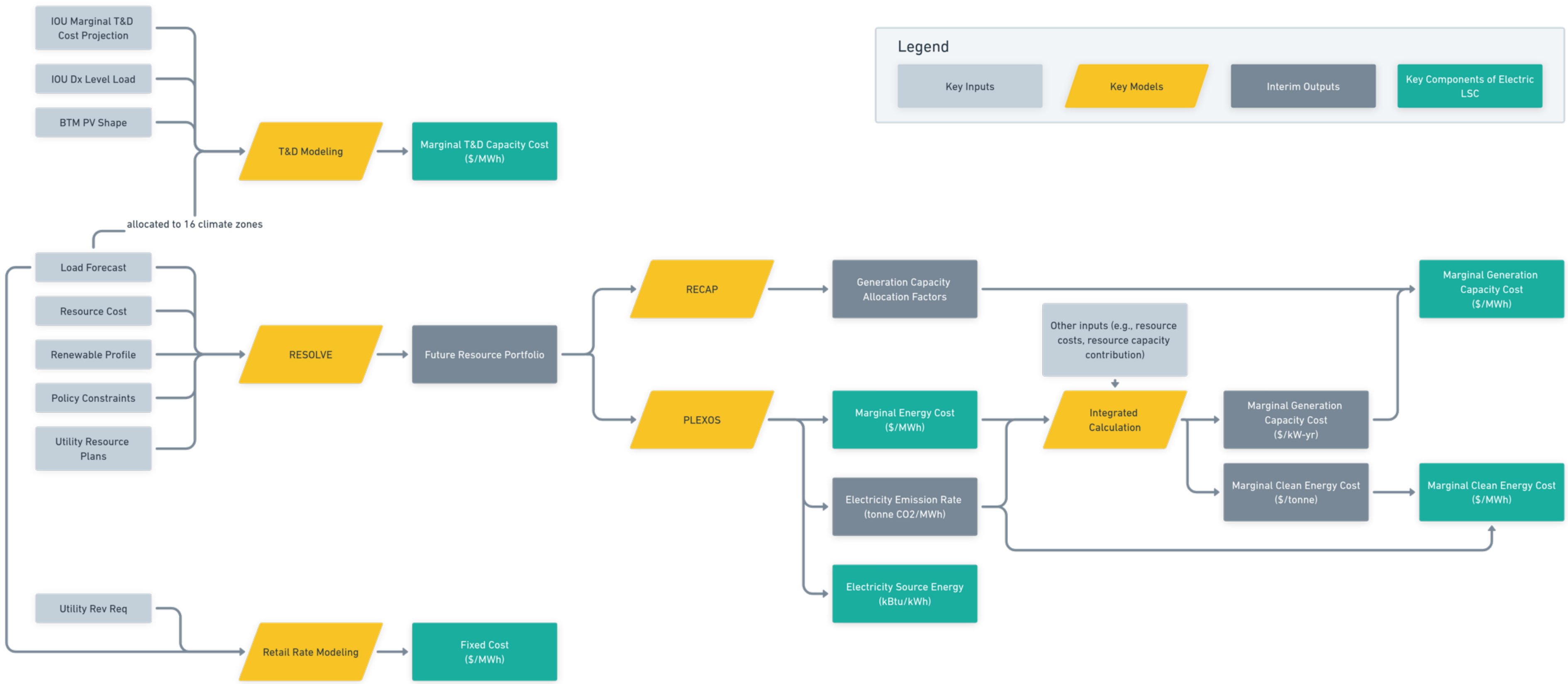


Table 3. Summary of Methodology for 2028 Electric LSC Components

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	PLEXOS Production Simulation results for years 2029, 2035, 2045 and 2050	PLEXOS Production Simulation Results
Generation Capacity	Integrated Calculation	Critical hours from RECAP
Clean Energy Costs	Integrated Calculation	Marginal emission rates from PLEXOS Production Simulation results
Ancillary Services	Scales with the value of energy	Directly linked with energy shape
T&D Capacity	Survey of investor-owned utility transmission and distribution deferral values from recent general rate cases	Hourly allocation factors calculated using hourly customer load forecast
Cap and Trade Emissions	2023 IEPR Final GHG Allowance Price Projections, floor	Embedded in energy prices and reflect emissions costs of the corresponding marginal fuel
GHG Emission Costs	EPA's 2023 report on the Social Cost of Greenhouse Gases	Constant allocation factor, does not vary by hour
Revenue Recovery Adder	Retail rate modeling	70% constant allocation factor, 30% time-dependent allocation

Key Methodology Changes

The 2028 LSC incorporates several methodological updates, including:

- Updated demand forecast data and load shapes
- Refinement of capacity cost allocation factors
- Updated utility circuit-level load data
- Incorporation of future climate conditions
- Updated retail rate forecasts
- Integrated calculation of capacity and clean energy costs
- Updated sources for GHG emissions costs

The updated demand forecast data and refined capacity cost allocation factors are described below, while the remaining methodological changes are detailed in the Appendix.

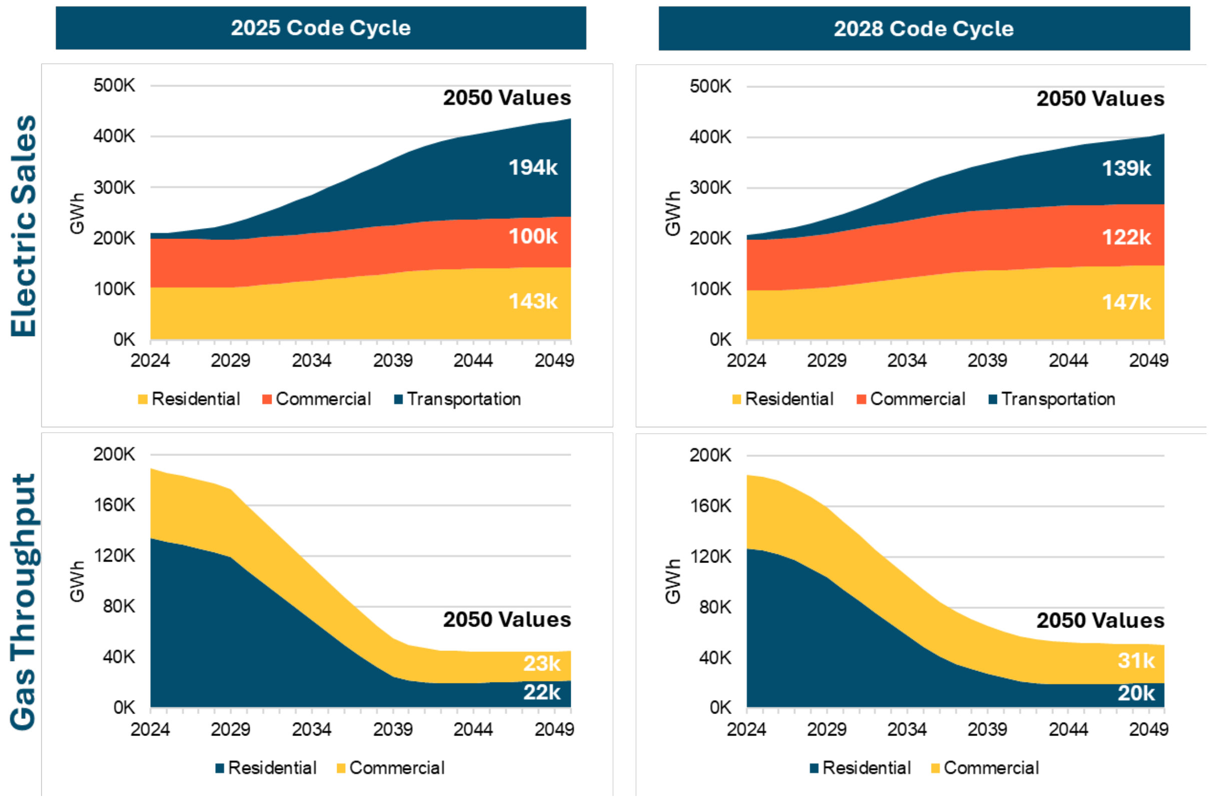
Updated Demand Forecast Data & Assumptions

Each code cycle, the process of developing LSC factors begins with selecting a demand scenario that includes specific strategies to achieve economy-wide decarbonization, which dictate sectoral emissions budgets and policy landscape. The selected demand scenario is intended to represent a realistic future scenario aligned with existing and anticipated future policy. This, in turn, determines building electrification load, EV load, decarbonized gas, and renewable generation procurement for the LSC modeling.

For the 2025 code cycle, the CEC chose a demand scenario from the 2021 CEC Demand Scenarios Project named the “High Electrification Policy Compliance” scenario. This demand scenario was aligned with current policy at the time, including SB100, and included relatively high economy-wide electrification, particularly in the transportation sector.

For the 2028 code cycle, a number of different demand scenarios were evaluated from publicly available scenario analysis, including the 2023 CEC Demand Scenarios Project, CARB Scoping Plan, and Integrated Energy Policy Report (IEPR). Ultimately, the CEC chose a hybrid scenario from the 2023 Demand Scenarios Project. The 2028 LSC factors use the building demand forecast from the “Reference” scenario and the transportation demand forecast from the “Policy Compliance” scenario. This hybrid demand scenario is aligned with current and proposed policy, including SB100, Advanced Clean Cars II, and CARB’s Zero Emission Appliance Standard. Compared to the demand scenario selected for the 2025 code cycle, the building demand forecast looks relatively similar. However, the transportation demand forecast has decreased, as a result of updates by the IEPR team to the EV adoption forecast.

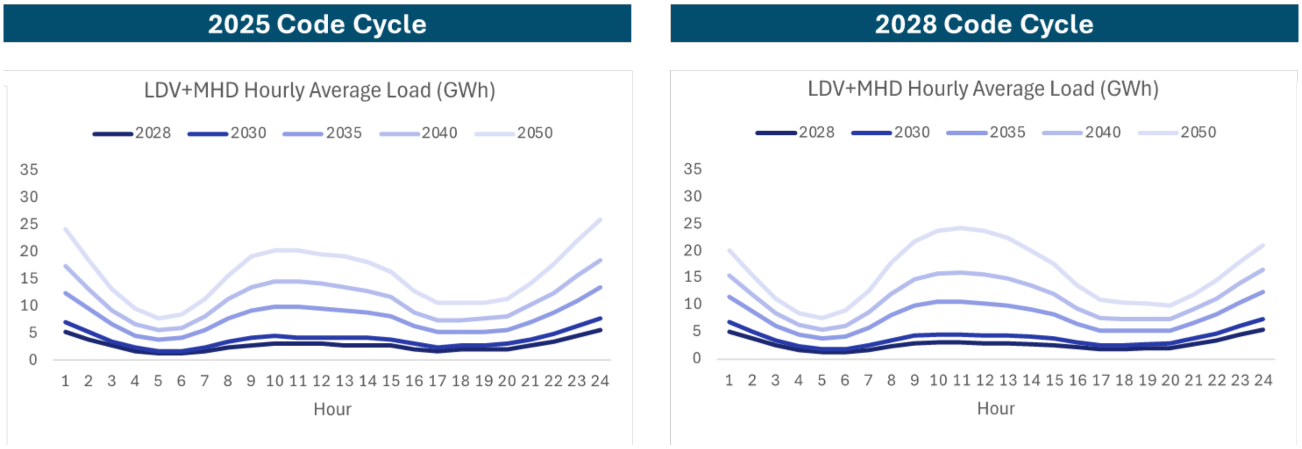
Figure 2. Electric Sales & Gas Throughput for Selected Demand Scenarios for 2025 and 2028 Code Cycles



In addition to a new demand forecast, the CEC also chose a new EV load shape for the 2028 code cycle. In the 2025 code cycle, EV load shapes from the 2021 IEPR were utilized. However, because these shapes were developed using today's time-of-use (TOU) rates, they include significant EV charging load during nighttime hours, when current TOU rates are lowest. Paired with high transportation load expected from the demand forecast, the modeling showed that in later years, the grid demand was going to peak in the middle of the night. While this reflects the best publicly available data at the time, the CEC does not expect that this EV load shape accurately reflects charging patterns with future TOU rates.

For the 2028 code cycle, resolution of this issue was a priority for the CEC. Instead of using charging shapes that just reflect today's TOU rates, a hybrid charging shape was developed in collaboration with the 2023 CEC Demand Scenarios project team that reflects 30% of EVs charging based on marginal costs by 2050, and the remaining portion of EVs charging based on today's TOU rates. The final EV shape has been adopted as the Policy Scenario with Managed Charging Sensitivity as part of the CEC Energy Assessment Division Demand Scenario Project.

Figure 3. EV Charging Shapes for 2025 and 2028 Code Cycles

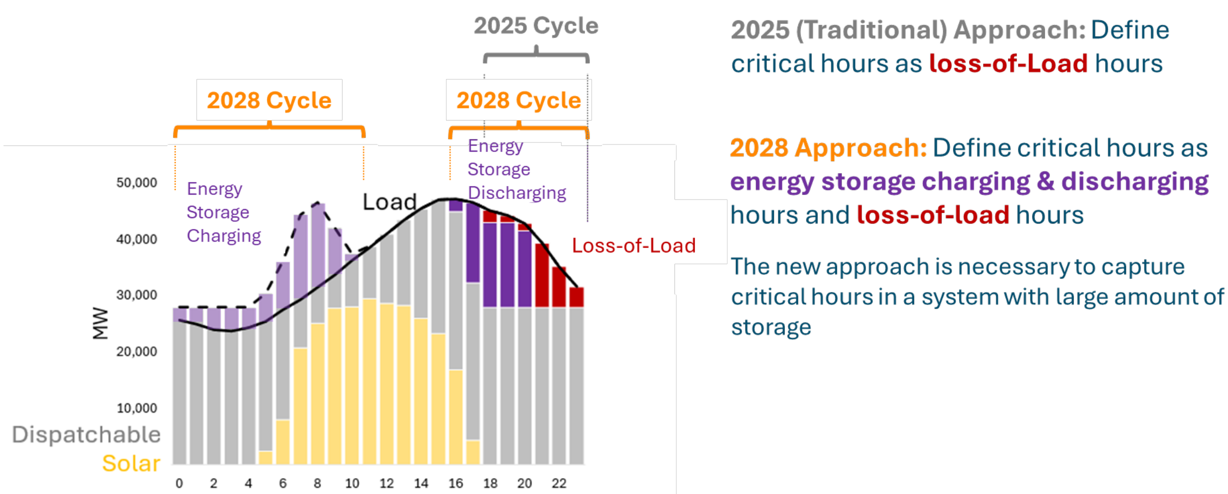


Refinement of Capacity Cost Allocation Factors

Electric generation capacity cost allocation factors are used to assign costs to the hours when reducing load most improves system reliability. These are referred to as *critical hours*. As shown in Figure 4, previous LSC cycles identified critical hours solely based on loss-of-load probability derived from reliability modeling in RECAP.

For the 2028 LSC, the definition of critical hours was expanded to also include hours when energy storage is actively charging or discharging on days with loss-of-load probability. This change reflects the evolving electric grid, where flexible storage resources play a critical role in mitigating reliability risks. By capturing the hours when storage is dispatched, the methodology recognizes that building load adjustments during these times can further defer storage use and enhance reliability.

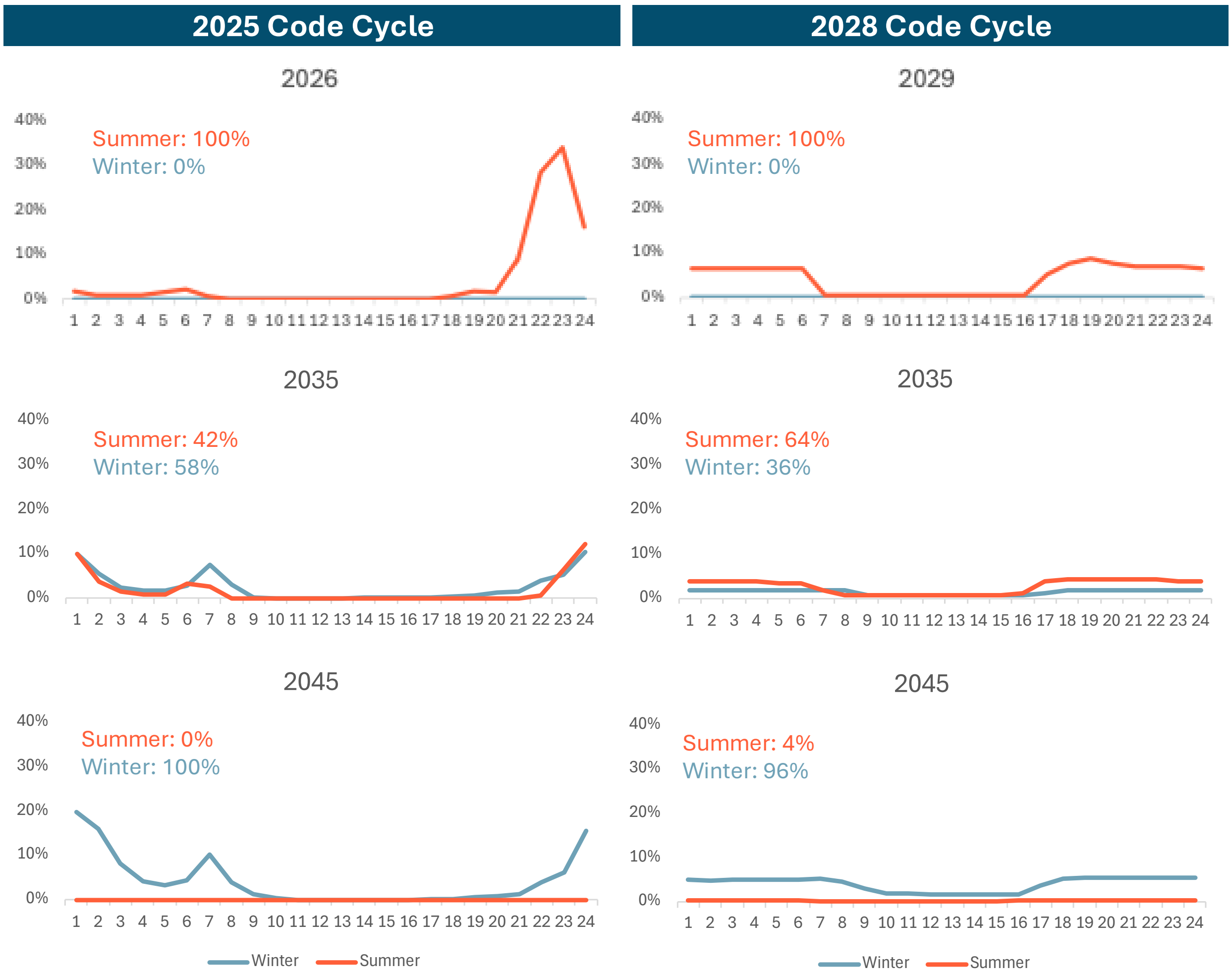
Figure 4. Illustration of Electric Generation Capacity Cost Allocation Methodology



Example Critical Day Dispatch

Including these additional hours results in a more distributed allocation of capacity cost on days with critical hours. While the total number of hours with non-zero allocation factors remains small, less than 5% of the hours in a year, those hours are spread more evenly across the critical day with the updated method (Figure 5). This adjustment better captures the value of electric load reductions in a system with high storage penetration.

Figure 5. Percent of Electric Generation Capacity Allocation Factors in Each Season-Hour



III. Evolving Metrics in the Changing Grid

This section provides some context on how and why the Energy Code metrics are evolving as California's electricity grid changes. These characteristics illustrate the future system's dynamics, even though they might appear counterintuitive based on grid operations today.

LSCs are now more correlated to net load than to outdoor temperature

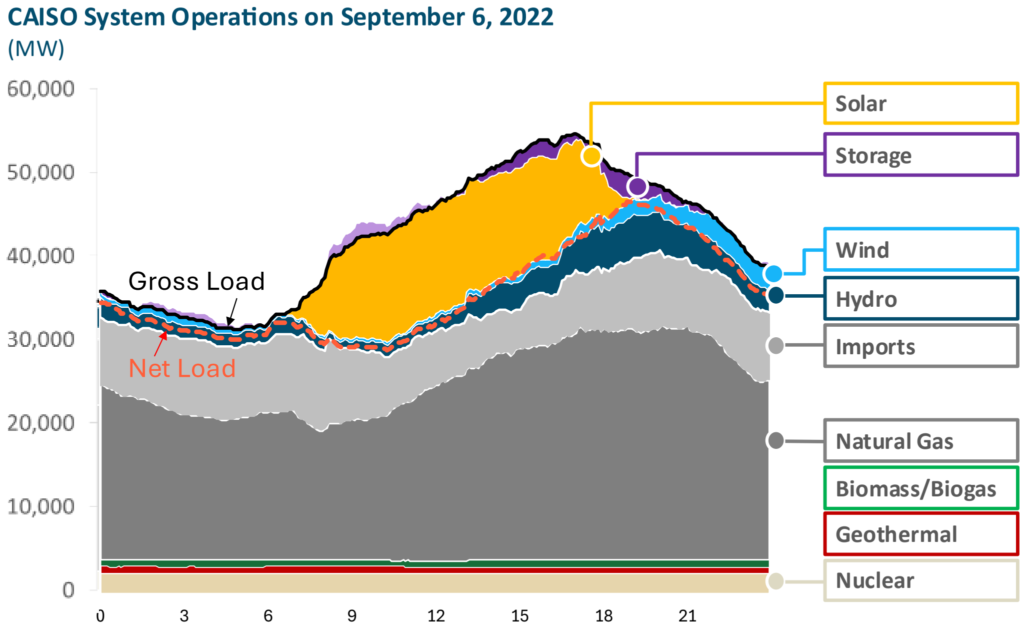
Historically, LSCs were closely linked to outdoor temperature variations, since customer load is temperature-sensitive and the electric system mainly dispatched thermal power plant resources[6], the higher the load, the higher the costs of serving load. However, as California adds increasing amounts of renewable energy, such as solar and wind, as well as storage to the grid, the relationship between energy use and grid stress has evolved.

With a growing share of electricity supplied by renewable resources and storage, the critical hour for the grid is no longer just when energy is consumed but also depends on the availability of renewable generation and storage resources to meet that load. Net load, defined as total system demand minus renewable generation, has become the key factor in determining grid stress periods and system costs. High LSC values tend to occur during periods when load is high and renewable generation is low. This marks a departure from the traditional assumption that high system costs always correspond with extreme outdoor temperatures since high system costs are expected to coincide with the combination of high temperatures and low renewable output more often in the future.

A real life example of this new dynamic was evident on September 6, 2022, when CAISO issued a Flex Alert requesting energy conservation from Californians. Although the gross load (total demand) peaked around 5 PM, the net load peaked two hours later at 7 PM, which marked the time when dispatchable resources or demand reductions were most needed. Notably, solar generation alone was insufficient to meet midday system demand on this day, prompting early dispatch of storage and gas resources to cover the gap. This is a contrast to typical spring days when solar alone could serve the entire load. This underscores how renewable output largely impacts the timing of system stress and the corresponding LSCs.

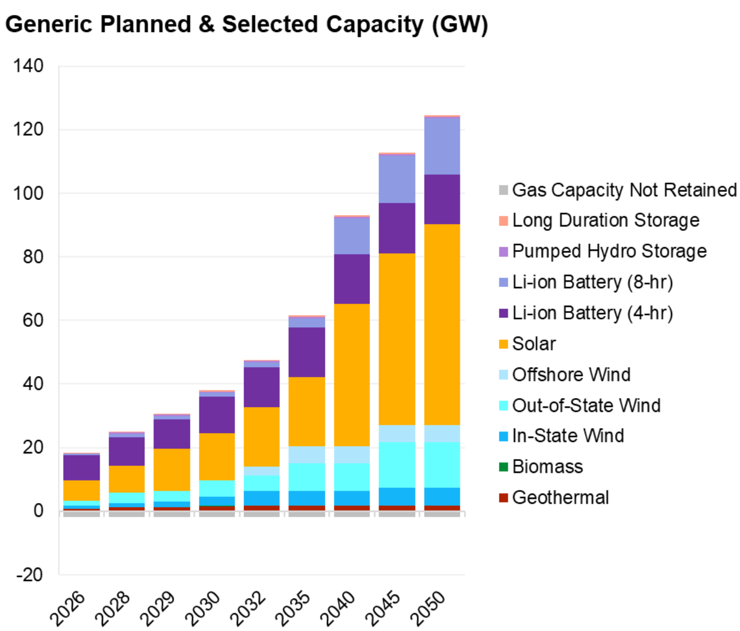
[6] A thermal power plant converts heat energy generated from various fuel sources (e.g., coal, natural gas, nuclear fuel, etc.) to electrical energy.

Figure 6. CAISO System Operations on September 6, 2022



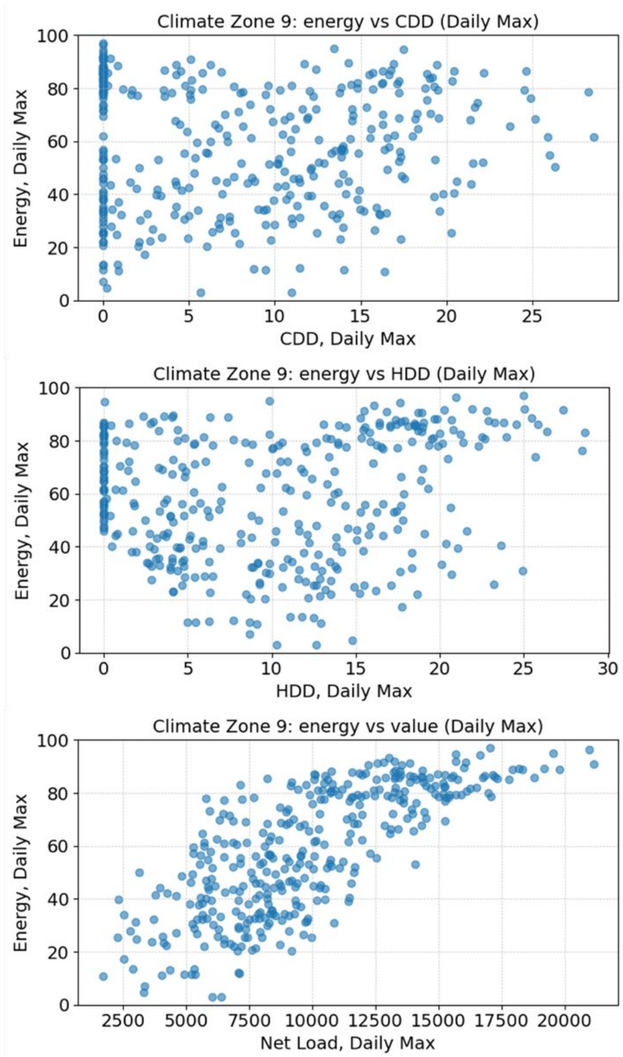
The 2028 LSC, which covers the period from 2029 to 2058, will reflect a grid increasingly dominated by renewable energy and supported by storage systems. Approximately half of this period extends beyond 2045, by which time California aims to achieve a 100% clean electricity grid under Senate Bill 100. As a result, LSCs continue to be driven by renewable generation in addition to overall demand (gross load) that is driven by high outdoor temperature.

Figure 7. Resource Additions for 2028 Electric LSC



As shown in Figure 7, the incremental resource buildout required to achieve California's decarbonization and reliability goals is primarily composed of solar, battery storage, and wind. Figure 8 shows that daily maximum marginal energy costs are more correlated to net load than cooling or heating degree days.

Figure 8. Daily Max Marginal Cost of Energy ($/MWh) vs Cooling Degree Days (CDD), Heating Degree Days (HDD) and Net Load (Climate Zone 9)



LSCs are increasing during winter months

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. However, as the grid shifts toward a 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 are changing. Specifically, the periods of high grid stress are increasingly occurring during winter months and other times when renewable generation is lower, and demand has increased from electrification.

Particularly in the winter, solar and wind output tends to be lower, especially during prolonged cloudy and calm conditions, which in Germany has been referred to as “Dunkelflaute.” These conditions can also occur in other seasons. These periods challenge grid operators because both solar and wind resources may be limited, leaving fewer clean options to meet electric demand. 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 and other seasons for this reason. This shift reflects the growing difficulty and cost of serving load under conditions of low renewable generation and high electricity demand.

LSCs are becoming flatter

Compared to the 2022 code cycle and earlier, the LSC values for the 2025 and 2028 cycles exhibit a flatter shape, with less variation between peak hours and the remaining hours. The primary driver behind this shift is the increasing role of energy storage in California’s grid. Energy storage acts as a flexible resource, charging when electricity is abundant and discharging during periods of higher demand. Incorporation of more storage as a resource to the grid helps smooth out sharp demand peaks, reducing the need for expensive, high-marginal-cost generation during critical hours.

Figure 9. Electric LSCs vs Temperature for 2022, 2025 and 2028 Cycles (Climate Zone 9)

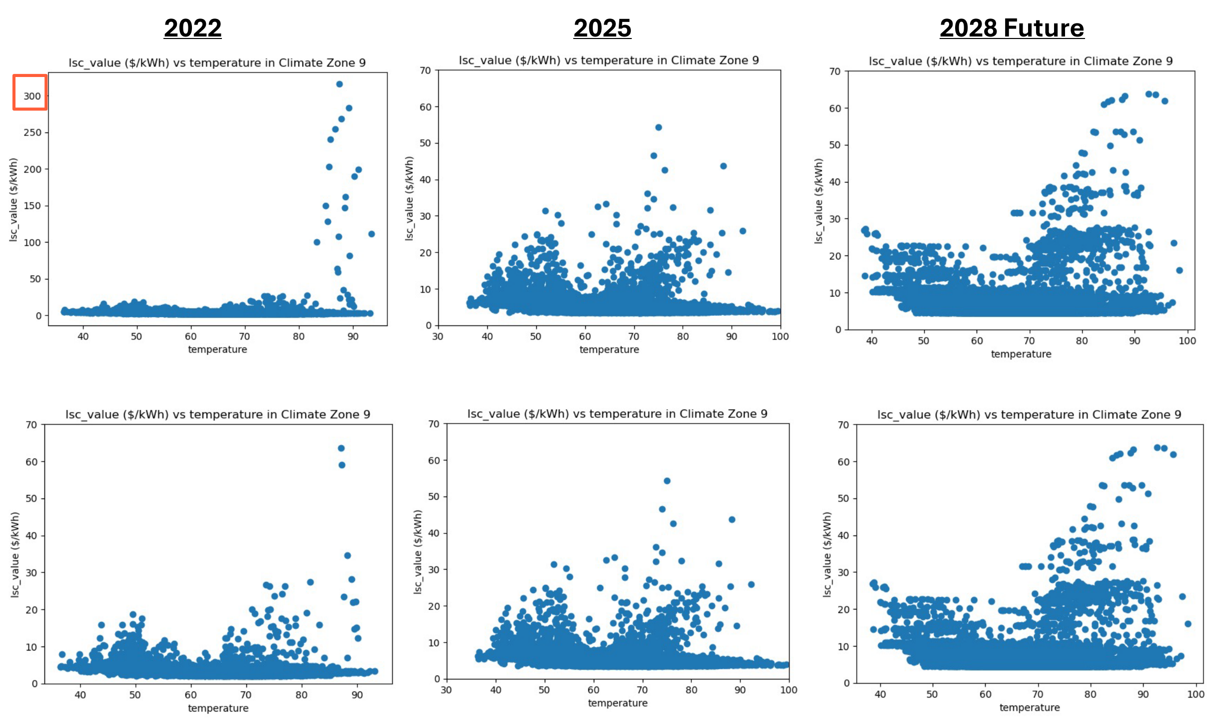


Figure 9 compares the hourly LSC values vs outdoor temperature across the 2022, 2025, and 2028 code cycles. The top and bottom rows display the same dataset. However, the top row includes all data points, while the bottom row uses the y-axis scale that represents all data points for 2025 and 2028. In 2022, very high LSC values were concentrated in a small number of summer hours, reflecting the grid's sensitivity to peak demand events occurring when outdoor temperatures were high. In contrast, the 2025 and 2028 LSCs do not rise to these very high LSC values, indicating that storage is helping to distribute demand and cost more evenly throughout the day and year.

The higher LSC values during colder winter months can also be seen in this figure, where the LSC distribution forms a distinct "U" shape across the temperature range. This pattern reflects increased system costs at both low and high temperatures. Aligning the y-axis scale in the 2022 LSC chart with those of the 2025 and 2028 LSCs in the bottom row reveals a similar trend had been occurring for the 2022 LSC, even though the overall shape in the 2022 LSC was dominated by the peak values during summer high outdoor temperatures.

IV. 2028 Metrics Results

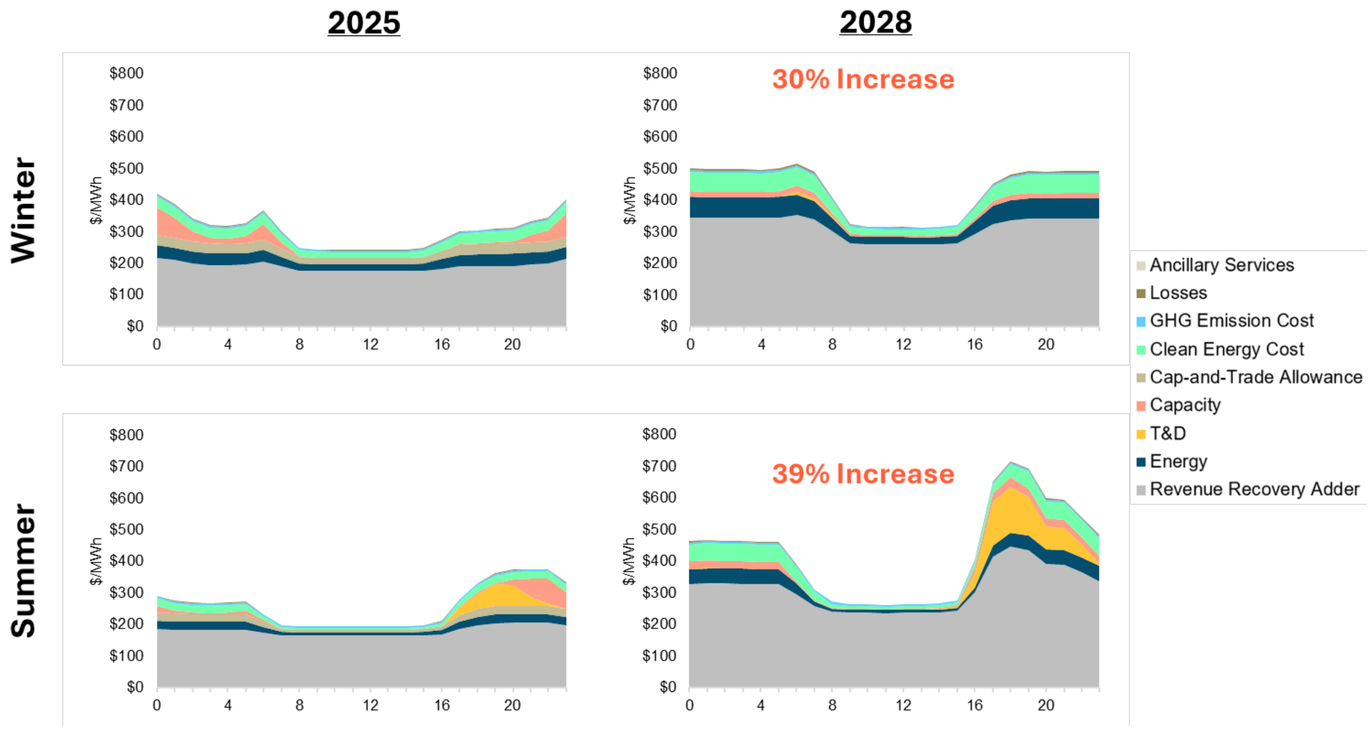
This section presents a summary of LSC results for the 2028 code cycle. Although there is variation across climate zones for some cost components, all results are shown for climate zone 9 for illustrative purposes.

Electricity LSC Results

Results for the 2028 electricity LSCs are shown below, in comparison to the 2025 LSCs. A summary of the major changes in electricity LSCs is as follows:

- Total magnitude of electric LSCs is larger than in the 2025 code cycle, as a result of higher retail recovery adders, reflecting higher electric retail rates, and higher clean energy costs, due to more years with 100% renewable energy
- Generation capacity costs are distributed over more hours, as a result of the updated capacity cost allocation methodology, and no longer spike in the middle of night, due to the updated EV charging forecast and load shape
- There is a more pronounced summer evening peak than in the 2025 code cycle, due to the inclusion of future weather and updated distribution load data

Figure 10. Climate Zone 9 Non-Residential Hourly Average Electricity LSC Factors for 2025 and 2028 Code Cycles, Levelized over 30-Year Analysis Period

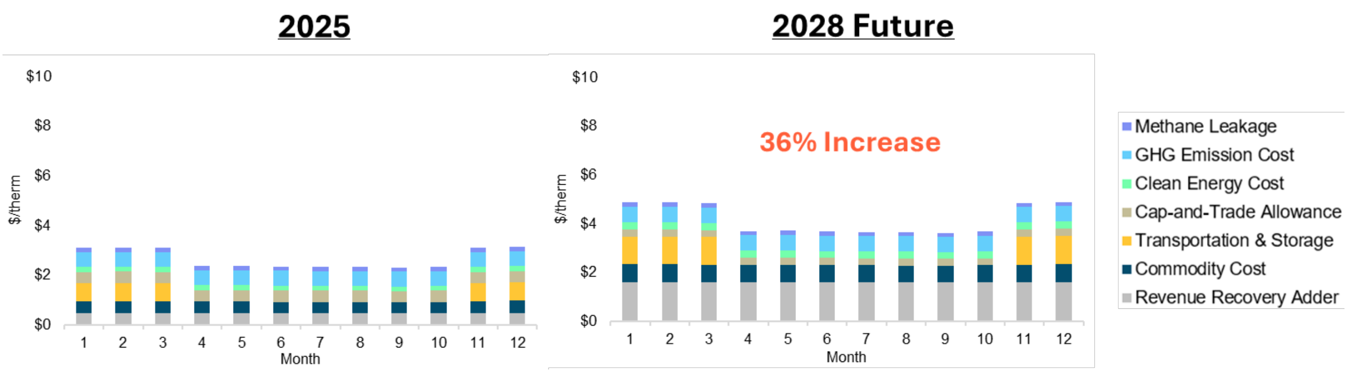


Gas LSC Results

Results for the 2028 gas LSCs are shown below, in comparison to the 2025 LSCs. A summary of the major changes in gas LSCs is as follows:

+ Total magnitude of gas LSCs is larger than in the 2025 code cycle, as a result of higher retail recovery adders and higher transmission & storage costs, both of which are driven by high fixed infrastructure costs and diminishing gas throughput due to electrification and future weather
+ Commodity costs and clean energy costs have both slightly increased since the 2025 code cycle, as a result of updated price forecasts and more years with some renewable gas in the pipeline
+ Cap-and-trade allowance, GHG emission cost, and methane leakage cost have largely remained the same since the 2025 code cycle

Figure 11. Climate Zone 9 Non-Residential Monthly Gas LSC Factors for 2025 and 2028 Code Cycles, Levelized over 30-Year Analysis Period

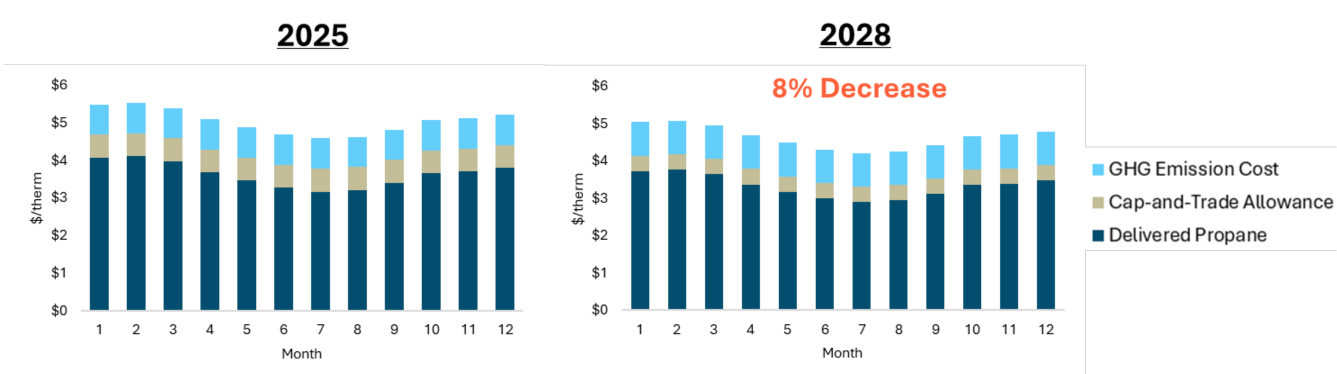


Propane LSC Results

Results for the 2028 propane LSCs are shown below, in comparison to the 2025 LSCs. A summary of the major changes in propane LSCs is as follows:

+ Total magnitude of propane LSCs is slightly lower than in the 2025 code cycle, as a result a lower delivered propane price forecast
+ Cap-and-trade allowance and GHG emission cost have largely remained the same since the 2025 code cycle

Figure 12. Climate Zone 9 Monthly Propane LSC Factors for 2025 and 2028 Code Cycles, Levelized over 30-Year Analysis Period

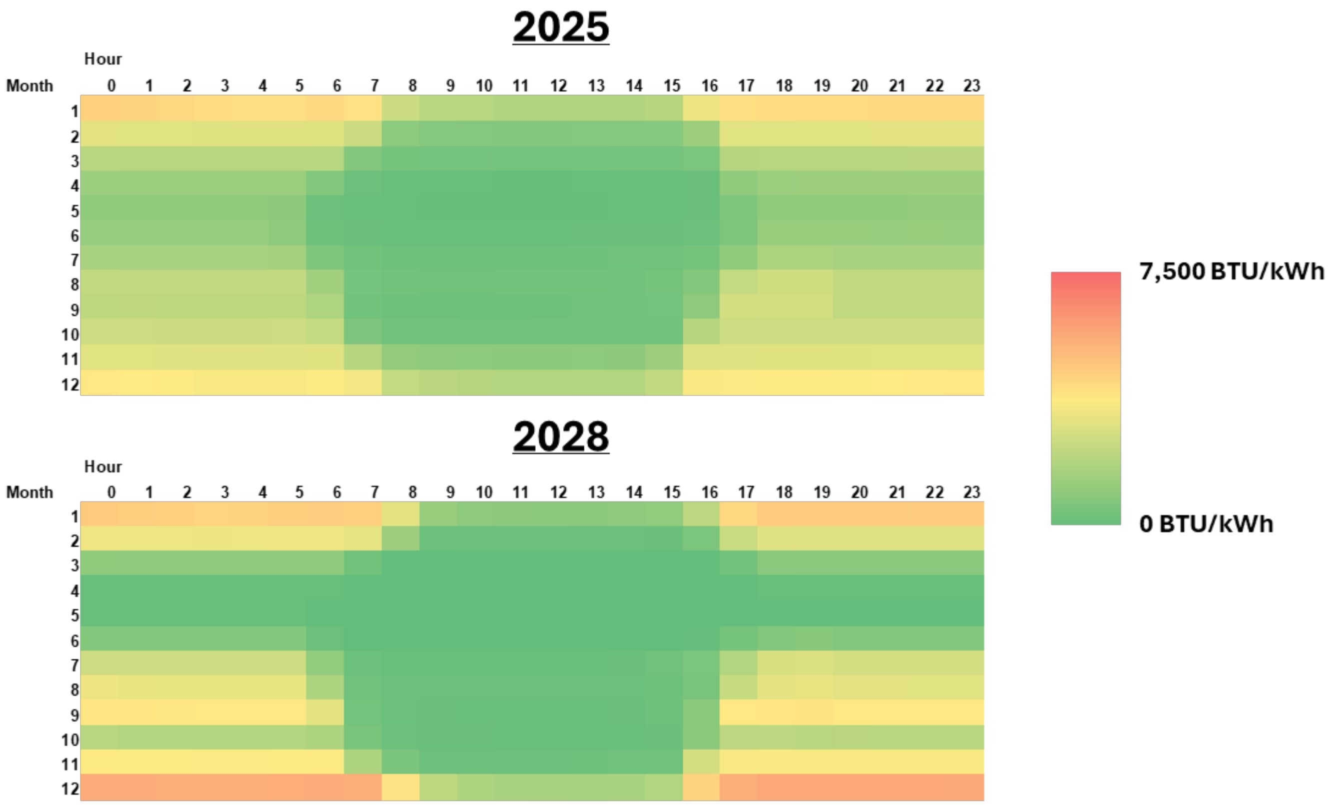


Source Energy Results

Results for the 2028 electricity source energy factors are shown below, in comparison to the 2025 source energy factors. A summary of the major changes in electric source energy factors is as follows:

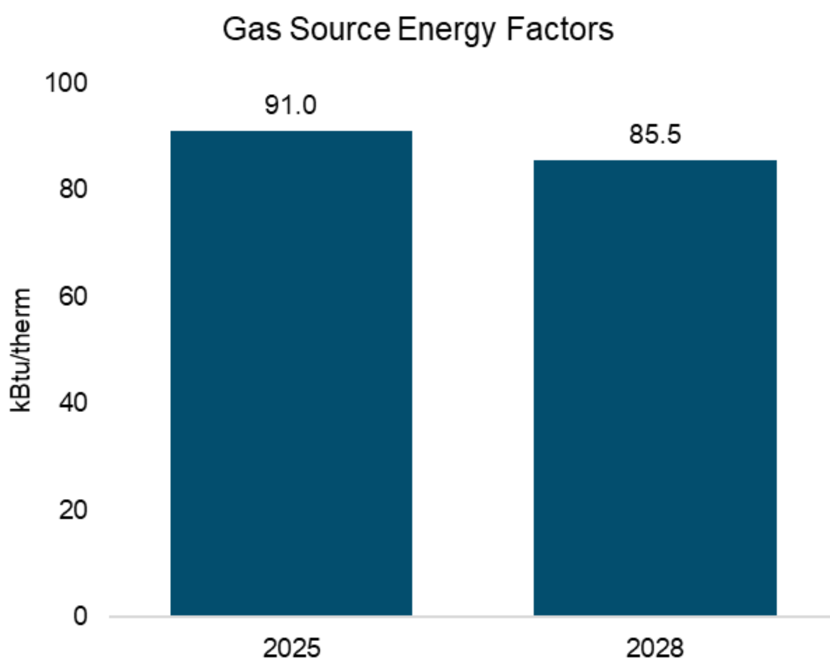
- Electric source energy factors are lower than the values from the 2025 code cycle at midday throughout the year, and all day in shoulder seasons (spring and fall), as a result of more years with high renewable penetration
- Electric source energy factors are higher than the values from the 2025 code cycle in Winter and Summer evenings and nighttime hours, while lower during the spring. This shift is primarily due to a change in how marginal heat rates were determined between the two code cycles. In the 2025 cycle, marginal heat rates were inferred from energy prices. For the 2028 cycle, they were directly output from the PLEXOS production simulation model. Using direct outputs from a production cost model like PLEXOS is a more accurate approach particularly in a future energy system with greater grid interconnection and widespread deployment of energy storage. In such a system, energy prices can be heavily influenced by low- or zero-fossil marginal cost resources like imports (e.g., hydro) or energy storage. These price signals do not necessarily reflect the actual marginal fuel-based generator on the system (typically a gas unit). Therefore, heat rates derived from energy prices can be lower than actual marginal heat rates in some hours while higher in others.

Figure 13. Month-Hour Average Electric Source Energy Factors



Results for the 2028 gas source energy factor are shown below, in comparison to the 2025 values. The gas source energy factor has decreased by about 7%. Following SB 1440, which authorized the CPUC to adopt biomethane procurement targets for the gas utilities it regulates, the CPUC set a target to procure 72.8 billion cubic feet of biomethane per year starting in 2030. Because a larger portion of the 30-year time horizon in the 2028 code cycle takes place after this 2030 target, the gas source energy factors have decreased.

Figure 14. Gas Source Energy Factors



Appendix

A.1. Principles of LSC

This section explains the basic concepts and approach used to develop the LSC methodology.

1. **Rational and Repeatable Methods**

   We have used published and public data sources for the fundamental analysis approach to developing LSC and source energy data. This allows revisions of the Energy Code and the underlying LSC data to be readily updated when called for by the California Energy Commission (CEC).

2. **Based on Hourly (or Monthly) Cost of Energy, Scaled to Retail Rate Levels**
   LSC is based on a series of annual hourly values for electricity cost (and monthly costs for natural gas and propane) in the typical meteorological year that is representative of the weather over the economic life of buildings subject to the Energy Code. The LSC values have been calibrated to match the statewide average retail rate forecast for residential and non-residential customers respectively. LSC values are developed for each of the sixteen climate zones.

3. **Seamless Integration within the Energy Code Compliance Methods**

   The mechanics of LSC should be transparent to the user community and compliance methods should remain familiar and easy. The LSC factors and source energy are developed such that they can be used as direct inputs in the Energy Code compliance software.

4. **Climate Zone Sensitive**

   As with the weather data used for Energy Code performance calculations, which allow building designs to be climate responsive, the LSC methodology also reflects differences in costs driven by climate conditions. For example, an extreme, hot climate zone has higher, more concentrated peak energy costs than a milder, less variable climate zone.

5. **Components of LSC**

   The LSC method develops each hour's (or month's) energy valuation using a bottom-up approach. We sum together the individual components of the cost of energy and then scale up the values such that over the course of the year the values are equal to the average forecasted retail rate for customers. The resulting electricity LSC factors vary by hour of day, day of week, and time of year. The key components of the electricity LSC factors are summarized below:

   - **Marginal Cost of Electricity**. These are the costs that change when electricity use increases or decreases. They include the cost of generating electricity, transmission and distribution during peak times, emissions, and other grid services.

These values reflect the time-specific cost to the system of using one more unit of electricity.

- **Revenue Recovery Adder**. These are costs that do not change when electricity load changes. They include costs like customer service, metering, billing, wildfire mitigation, and other non-variable charges. These are spread over all hours to ensure the total LSC matches forecasted retail revenues.

A.2. Frequently Asked Questions and Answers

1. What is Long-Term System Cost (LSC)?

   - Long-Term System Cost (LSC) is a cost metric, with units of $/kWh and $/therm for electricity and natural gas, respectively. LSC represents hourly long-term costs to the energy system over 30 years and does not represent annual utility bill savings and is used in development and implementation of the Energy Code. LSC factors are used to convert predicted site energy use to a 30-year present value cost to California's energy system. Since the time when energy is used is as important as the amount of energy used, these factors are generated on an hourly basis for a typical meteorological year that is representative of the weather over the economic life of buildings subject to the Energy Code, and created for each of California's diverse climate zones[7]. The time dependent nature of LSC reflects the underlying marginal cost of producing and delivering an additional unit of energy, the time of use structure of retail tariffs, and the resulting economic signal aligns energy savings in buildings with the cost of producing and delivering energy to consumers.

2. How is LSC used?

   - The CEC uses LSC in its California Building Energy Code Compliance (CBECC) software to set the target energy budgets for newly constructed buildings, and to value the design trade-offs made during the development and construction of those buildings. The LSC metric is also used for determining the long-term cost effectiveness of proposed energy efficiency measures.

3. Why does the LSC method yield different values than first-year utility bill?

   - The LSC of energy is reflective of a 30-year net present value cost of energy to the statewide energy system. This differs from a first-year utility bill in that the LSC is constructed from a long-term forecast of hourly electricity, natural gas and propane

[7] For mor details, see "Weather Data File Updates for the 2028 Energy Code," https://efiling.energy.ca.gov/GetDocument.aspx?tn=265692&DocumentContentId=102543.

costs, consistent with the latest CEC forecasts and outlook for California's energy sectors, whereas the first-year utility bill reflects only today's rates. Additionally, LSC values represent sector-wide averages for residential and non-residential customers, rather than the specific retail rates that individual customers pay today.

4. Why do the LSC values vary with time?

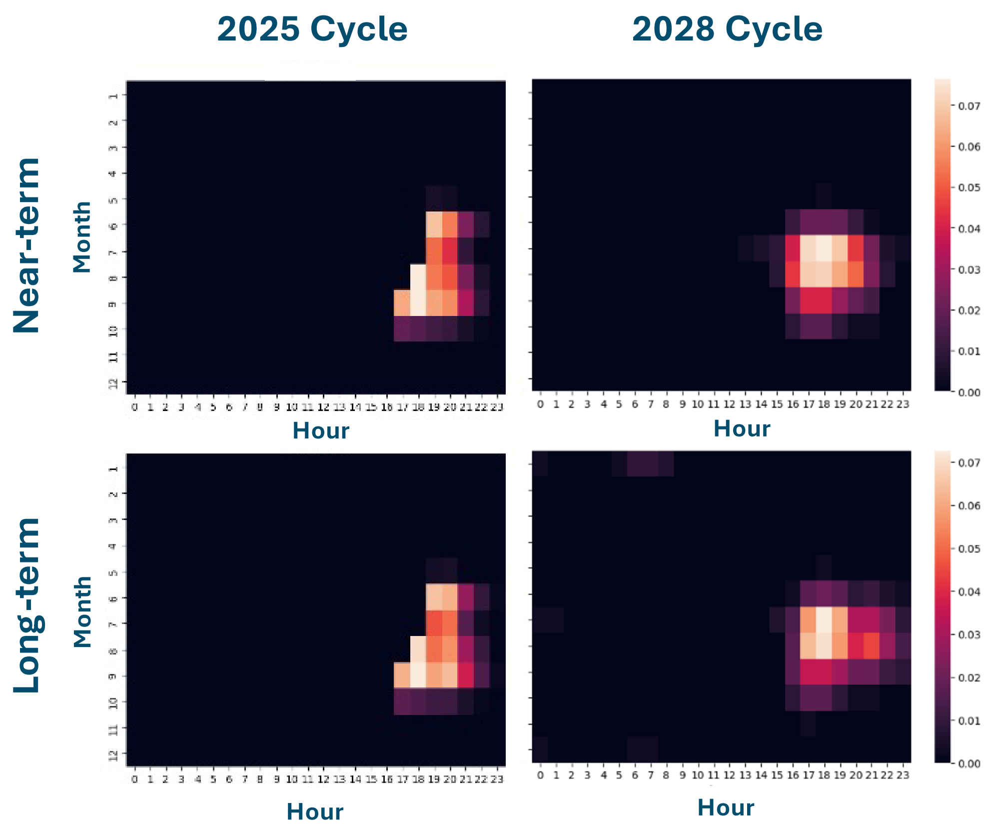
    - Since 2005, the Energy Code cost effectiveness metric has varied with the time and season when the energy is provided by the system to meet total system load. The LSCs are established by the multiple components that are marginal costs that vary depending on system load, and the revenue recovery adder that represents costs that do not vary with system load. The combination of all of these components establish the long-term revenue requirements that must be recovered through retail rates over the 30-year period. The revenue recovery adder varies also by time-of-day and season to align with how time-of-use rates are structured. This means that the LSCs provide an economic signal to save energy that is aligned with the times that saving that energy is most valuable. The approach of using marginal cost components and higher peak costs for the revenue recovery adder reflects a long-term trend toward retail rates that increasingly reflect the marginal cost of service and ensure that the building energy efficiency code provides the greatest value to the energy system.

A.3. 2028 LSC Remaining Methodology Changes

Updated Utility Circuit-Level Load

One key input in LSC development is hourly electric utility circuit load data. This data is used to understand where there will be the most strain on the transmission and distribution system within each Investor-Owned Utility (IOU) service territory, and is critical to allocate T&D costs across the year. For the 2028 code cycle, through collaboration with the California Public Utilities Commission (CPUC) and the IOUs, a new dataset of local load data was acquired. This new dataset ensures that the T&D cost allocation done for this code cycle reflects the most up-to-date feeder load shapes.

Figure 15. T&D Allocation Factors for 2025 and 2028 Code Cycles, Based on Updated Feeder Load Data (Example for Climate Zone 9)



Incorporating Future Climate into the 2028 LSCs

A major update in the 2028 LSC methodology is the explicit incorporation of future climate conditions. To better reflect anticipated weather impacts from climate change, the CEC has developed a new set of Typical Meteorological Year (TMY) datasets. Please see "Weather Data File Updates for the 2028 Energy Code" memo for the detailed methodology (https://efiling.energy.ca.gov/GetDocument.aspx?tn=265692&DocumentContentId=102543).

In addition to the single-year TMY, multi-year TMY datasets have also been developed for the purposes of modeling electric sector operations under different weather conditions. These represent a broader range of variability in the future climate and were used in system modeling steps, specifically the RESOLVE capacity expansion model and the RECAP reliability model. These multi-year datasets allow the modeling to capture variability in weather-dependent loads and generation, while the final LSC metrics correspond to the single-year TMY.

Incorporating future climate data into the LSC methodology directly affects two critical inputs:

- **Weather-dependent end-use load profiles** (e.g., space heating and cooling). To align end-use load profiles with projected climate conditions, E3 first develops a broad set of hourly load simulations spanning 1998–2022. To do so, E3 develops a regression model relating historical load to observed weather conditions. This model is then applied to historical weather data to generate a consistent set of simulated loads across all historical years. These simulations are matched to future month-year combinations from the future weather datasets and led to single-year and multi-year weather-aligned load profiles. All weather-dependent load, including base load (i.e., load as of today) and incremental loads from electrification, is adjusted.

- **Renewable generation profiles** (e.g., solar and wind output). E3 uses a similar month-year alignment approach to generate renewable generation profiles. First, historical solar irradiance and wind speed data are gathered and input into NREL's System Advisor Model (SAM) to estimate hourly solar and wind output for years 1998-2022. These generation profiles are then converted to single-year and multi-year generation profiles to match the future weather dataset.

Both the load and renewable generation profiles are foundational to the LSC metric, which evaluates the time-varying costs of the state's energy system over a 30-year time horizon. By aligning both demand and supply-side inputs to future climate conditions, the 2028 LSCs better reflect the cost and emissions implications of building energy use under warming scenarios.

Updated Retail Rate Forecasts

To develop the LSC factors, a retail rate forecast is needed to calculate the additional retail recovery adder that is not accounted for in the marginal cost components. Historically, LSCs have used gas and electric retail rate forecasts from the latest IEPR.

Since the 2025 code cycle, the natural gas retail price forecast has been developed using a new methodology that is tailored to the specific demand scenario selected by the CEC. This methodology incorporates the gas throughput forecast from the selected demand scenario, gas revenue requirement from the latest utility General Rate Cases (GRCs), revenue requirement escalation rates from the 2021 IEPR, and a gas commodity cost forecast from New York Mercantile Exchange (NYMEX) future prices, also referred to as NYMEX forwards. With a high electrification demand scenario, there is substantial reduction in gas throughput through the gas distribution system. In addition, with future weather, the winters are warmer and there is less heating load which further reduces natural gas demand. Because fixed costs of the natural gas distribution system are spread across a smaller amount of volumetric consumption, this drives up the natural gas retail rate.

For the 2028 code cycle, this same methodology is used to calculate a new gas retail price forecast, using updated inputs from the selected demand scenario, 2023 IEPR, latest GRCs, and NYMEX forwards. Additional work was done for this code cycle to accurately capture cost allocations of gas revenue requirements across the different customer classes, and how those allocations are likely to change in the future. As gas throughput in each customer class decreases at different rates in the selected demand scenario, the class allocations for a portion of the revenue requirement associated with transmission and storage is also likely to shift.

An additional input that is key to the gas retail rate forecast is the throughput of renewable natural gas in the pipeline. Pursuant to SB 1440, which authorized the CPUC to adopt biomethane procurement targets for the gas utilities it regulates, the CPUC set a target to procure 72.8 billion cubic feet of biomethane per year starting in 2030. This procurement, which is reflected in the LSCs as the Clean Energy Cost, was incorporated into the gas retail rate forecast starting in the 2025 code cycle. Because a larger portion of the 30-year time horizon in the 2028 code cycle takes place after this 2030 target, the Clean Energy Cost has increased.

Figure 16. PG&E Non-Residential Gas Rate Forecast for 2028 Code Cycle, Broken out by Cost Component

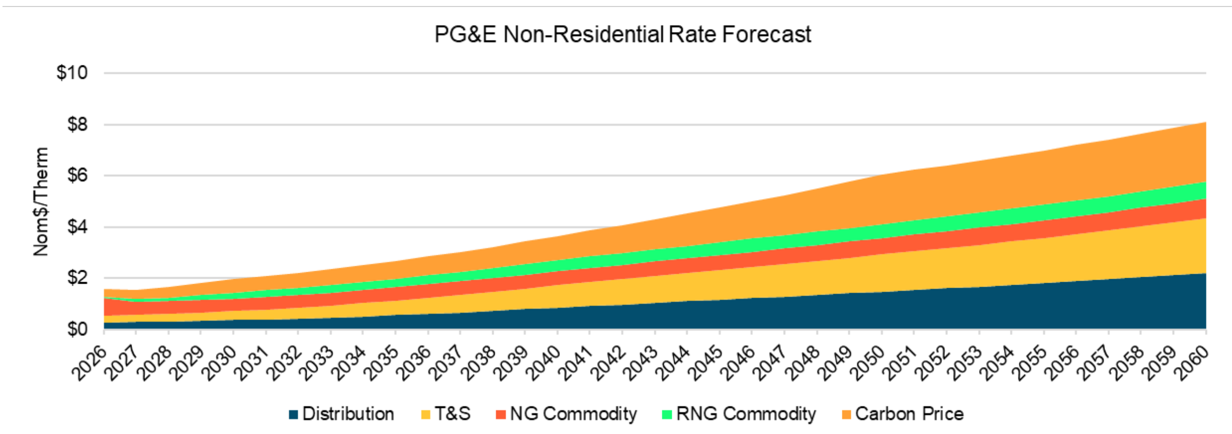
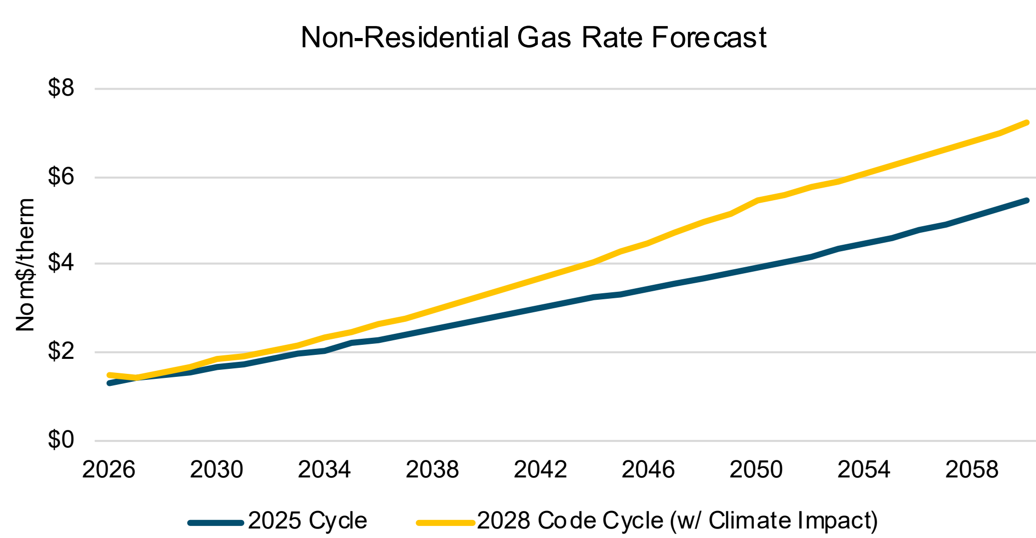
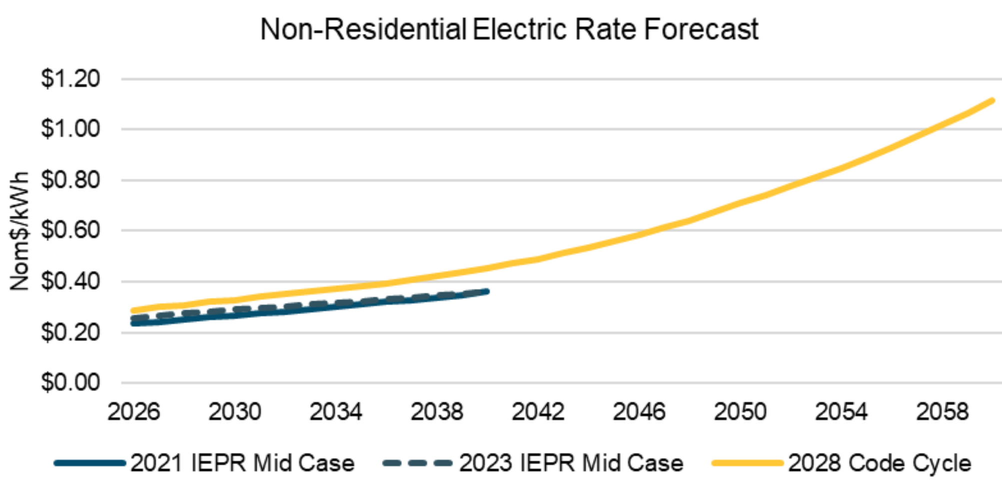


Figure 17. Non-Residential Gas Rate Forecasts for 2025 and 2028 Code Cycles



Starting in the 2028 code cycle, rather than using the electric retail price forecast from IEPR, an electric retail price forecast has been developed using a new methodology that is tailored to the specific demand scenario selected by the CEC. This methodology incorporates the electric sales forecast from the selected demand scenario, electric revenue requirement from the 2023 IEPR, and incremental distribution and generation revenue requirement from electrification beyond the IEPR demand scenario.

Figure 18. Non-Residential Electric Rate Forecast for 2028 Code Cycle



Integrated Calculation of Capacity and Clean Energy Costs

Prior to the 2028 Energy Code cycle, the marginal costs of generation capacity ($/kW-yr) and clean energy costs ($/tonne) were determined independently:

+ **The marginal costs of generation capacity**, representing the incremental costs of procuring one megawatt of additional capacity, was determined by calculating the "missing money" of a marginal capacity resource (energy storage) in each year. "Missing money" refers to the shortfall between a resource's total fixed costs and the net revenues it is expected to earn from energy and ancillary services (AS) markets. For most resources, energy and AS revenues alone are insufficient to fully cover their total fixed costs, and so this "missing money" value is non-zero.
+ **The clean energy costs**, intended to reflect the incremental costs of supply-side resources needed to reduce emissions by one metric ton, was tied to the "shadow price" of the GHG planning target constraints in RESOLVE. The "shadow price" reflects the incremental cost of reducing one additional tonne of GHG in a given modeling year.

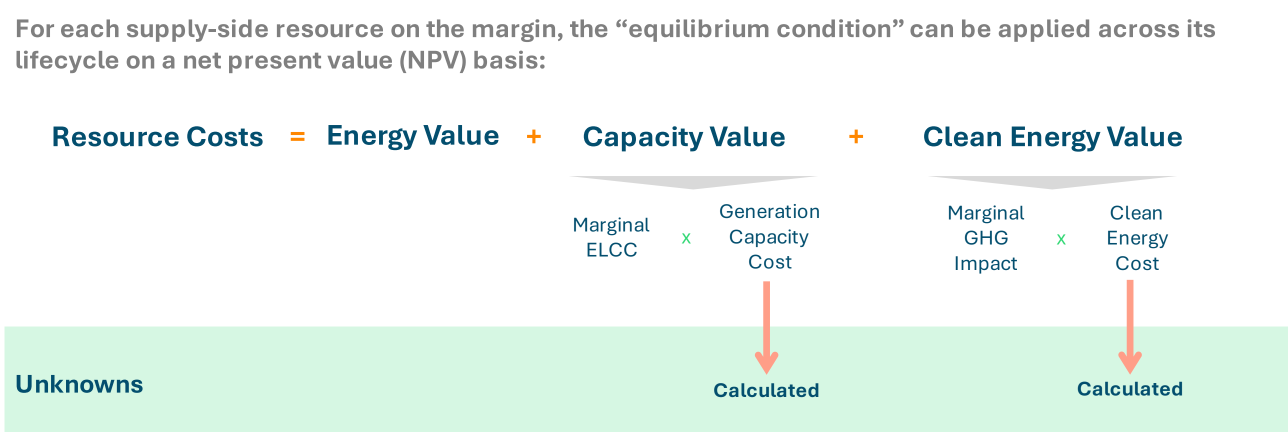
The 2028 LSC combines the determination of generation capacity costs and clean energy costs into a single step, the Integrated Calculation of Generation Capacity and Clean Energy Costs ("Integrated Calculation"). The rationale for this improvement is that these two cost streams are inherently interdependent. Resources such as solar and storage are procured to **simultaneously meet both** the state's reliability needs and decarbonization goals, and these cost streams represent the implicit and explicit price signals to procure the resources needed.

Under this integrated approach, resources selected to serve both reliability and emissions reduction objectives must receive adequate compensation to meet their revenue requirement, which is the total revenue necessary to recover all fixed costs and earn a reasonable return on investment. Evaluating these costs together through the Integrated Calculation approach ensures that compensation does not exceed revenue requirements, thus avoiding resource overcompensation borne by ratepayers that may occur if the costs are evaluated independently.

The Integrated Calculation ensures that the combined compensation from energy, generation capacity, and clean energy revenue streams *equals* the resource's levelized fixed cost on a net present value (NPV) basis. Specifically, energy market revenues are determined directly from PLEXOS results. Marginal generation capacity and clean energy costs are then calculated so that, when combined with energy revenues, the total value aligns with the resource's levelized cost. Figure 19 illustrates the core equation in the Integrated Calculation. While generation capacity costs and clean energy costs are calculated, the other components are inputs drawing from the following sources:

- Resource costs are based on levelized cost assumptions in RESOLVE
- Energy Value is calculated based on PLEXOS energy prices and resource generation profiles
- Marginal Effective Load Carrying Capability (ELCC) represents the marginal reliability contribution of a given resource and is derived from RESOLVE outputs.
- Marginal GHG impact is calculated based on PLEXOS marginal emission rates and resource generation profiles.

Figure 19. Conceptual Illustration of the Integrated Calculation



Updated Source of GHG Emissions Cost

GHG Emission Costs (previously called emission abatement costs) represent the societal cost of residual greenhouse gas emissions. Residual emissions remain even as California pursues its long-term decarbonization goals. For example, combustion of natural gas in buildings still contributes to emissions. Accordingly, these residual emissions impose a societal cost that should be reflected in long-term energy planning.

There are two primary approaches for quantifying this societal cost:

- Emission Abatement Costs, which estimate the marginal cost of achieving additional emissions reductions (e.g., from deeper electrification or carbon capture) to offset residual emissions; and
- Cost of Damage, which estimates the economic, health, environmental, and social damages caused by a metric ton of GHG emissions.

In prior LSC cycles, the GHG Emission Cost was derived from the marginal cost of achieving additional GHG reductions in the electricity sector, which was the same value as the clean energy costs. This reflected an assumption that electricity would continue decarbonizing beyond its own requirements to offset emissions in harder-to-decarbonize sectors.

However, with the implementation of SB 100,[8] which requires California's electricity supply to be 100% zero-carbon by 2045, the assumption of unlimited emissions abatement in the electric sector is no longer realistic. This prompted the need for a new, more economy-wide basis for estimating the societal cost of residual emissions.

For the 2028 LSCs, the GHG Emission Cost is based on the U.S. EPA's 2023 report on the Social Cost of Greenhouse Gases.[9] This report provides monetized estimates of the damages from incremental emissions of carbon dioxide, methane, and nitrous oxide. The updated estimates were developed using a peer-reviewed methodology that includes updated climate damage functions that reflect current scientific understanding of how emissions impact health, agriculture, sea level rise, and labor productivity. It also includes a probabilistic approach that accounts for uncertainty in climate sensitivity and economic impact over a 300-year horizon. Figure 20 compares GHG emission costs between 2025 LSC and 2028 LSC.

[8] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB100
[9] https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf

Figure 20. Comparison of GHG Emission Costs between 2025 LSC and 2028 LSC