2026 Avoided Cost Calculator Staff Proposal

FILED
06/05/26
09:12 AM
R2211013

April 2026

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1 Introduction

This document summarizes California Public Utilities Commission (CPUC) staff proposals for the 2026 update to the CPUC's Avoided Cost Calculator (ACC), for consideration as part of Track 1 of Rulemaking (R.) 22-11-013.

2 Refinement of GHG Avoided Costs

Staff propose three related modifications to increase consistency and transparency of greenhouse gas (GHG) avoided costs within the electric and gas ACC models:

1. Apply a single value to GHG emission reductions.
2. Remove the GHG Rebalancing component.
3. Cap total GHG value at the societal cost of carbon.

This section provides additional background on the motivation for these changes and details of the proposed changes themselves.

2.1 Background

2.1.1 Electric Sector GHG Planning in Context

The state's overarching greenhouse gas emissions target—achieving carbon neutrality by 2045—is economy-wide, encompassing all sectors including transportation, buildings, industry, and electricity generation. In theory, planning the most efficient path to that goal would involve **integrated, economy-wide modeling** that identifies the least-cost combination of GHG reductions across sectors and produces a single, consistent marginal cost of carbon. Such a framework would ensure that all GHG reductions, regardless of sector, are valued equally and consistently, encouraging decarbonization where it can be achieved most cost-effectively.

In practice, California's planning process is more complex. While the Cap-and-Invest program provides a common price floor, the state has developed several parallel **sector-specific programs**—such as the Renewable Portfolio Standard, building and transportation electrification initiatives, and appliance standards—that reflect differences in policy levers, regulatory oversight, and technological readiness.

This sector-by-sector approach means that while California's overall climate goals are economy-wide, the GHG targets, cost signals, and planning responsibilities are divided across regulatory agencies and proceedings. In addition, the electric sector operates under an administratively defined emissions cap supported by detailed modeling that clearly establishes a marginal GHG abatement cost. By contrast, similarly robust analytical frameworks have not been implemented to establish GHG abatement costs in the transportation and natural gas sectors.

2.1.2 Integrated Resource Planning and electric sector GHG targets

The CPUC has established an electric-sector GHG emissions cap, expressed in million metric tons (MMT), that is consistent with the statewide trajectory defined in the California Air Resources Board's (CARB) Scoping Plan. This cap has been reduced over the past several IRP cycles, representing increasing ambition for electric GHG reduction. The CPUC IRP subsequently employs capacity-expansion modeling to identify the least-cost portfolio of resources that meet reliability requirements, clean-energy standards, and an electric sector-specific GHG emissions target. The resulting system plan produces a marginal GHG abatement cost that reflects the cost of achieving additional emission reductions through the procurement of clean energy resources.

With both renewable generation and electrification as key decarbonization pillars, the IRP approach embeds a close relationship between forecasted load and GHG policy compliance obligations for the electric sector. Over time, CPUC and CARB is able to revisit the electric-sector share of statewide emissions to ensure that the sector's target remains aligned with the state's parallel GHG reduction strategies. Adjustments to the electric-sector emissions cap are therefore made iteratively through each IRP cycle as load forecasts, technology costs, and as state policy evolves.

The particular emphasis on the electric sector in California's GHG emissions reduction strategy stems from several factors: California has clear statutory authority and long-standing planning processes governing the electric system, those processes are supported by mature regulatory tools for long-term resource planning, and decarbonizing the electricity supply enables emission reductions in other sectors through electrification.

2.1.3 Electric sector GHG avoided costs

In the ACC electric model, the GHG value represents the marginal cost of reducing emissions within the electricity sector and is applied to changes in electric-sector load from DERs. The GHG value is composed of the Cap-and-Trade value, which represents the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) price forecast for California's Cap-and-Invest[1] program, and an additional GHG Adder, which represents the additional costs needed beyond the Cap-and-Invest program to meet the electric sector GHG target. The Cap-and-Trade value plus the GHG Adder sum to the implied marginal GHG abatement cost for the electric sector.

In addition, the GHG Rebalancing component represents an assumed change to the electric sector GHG target due to changes in load or distributed generation. The impact of building and transportation electrification exemplifies the rationale for the GHG Rebalancing component in the ACC. Building and transportation electrification measures reduce GHG emissions overall but add load to the electric system. If electrification load were added to an electric sector IRP portfolio, one could expect that, in the long-term, the allowable GHG emissions from the electric sector would increase proportionally, not to remain fixed at the original total emissions target.

[1] Formally called the Cap-and-Trade program. The 2026 ACC will be updated to reflect the new Cap-and-Invest program name.

This approach uses the *average* grid emissions intensity of the modeled IRP portfolio to calculate a portfolio rebalancing impact. This approach makes the simplifying assumption that the average grid intensity is a reasonable reflection of the electric sector's proportional responsibility for meeting California's total GHG emissions target. Thus, when considering incremental changes in load, the allowable GHG emissions from the electric sector changes proportionally with average grid emissions intensity in tonnes of GHG per kWh. The GHG Rebalancing component applies the GHG Adder to proportional changes in load.[2]

2.1.4 Natural gas sector GHG avoided cost

In the ACC gas model, an interim GHG value has been adopted for the natural gas sector for the last two ACC update cycles. The interim GHG value was intended to reflect the cost of decarbonizing direct natural gas combustion in buildings through building electrification or use of renewable natural gas or other fuels. Building decarbonization policy mandates for the natural gas sector imply higher marginal costs for achieving GHG reductions than in the electric sector. Assuming renewable natural gas supplies are likely to be targeted for other hard-to-electrify applications such as transportation, building electrification was found to be the best proxy for a marginal resource for replacing natural gas use. The interim GHG value was based on the $114/tonne GHG abatement cost for residential building electrification from a CEC report[3], escalated at the utility weighted-average cost of capital (WACC) from 2020 to 2054.[4] Since the interim GHG value was adopted in 2022, more robust analysis quantifying a natural gas sector specific marginal GHG value has not been completed.

A comparison of the GHG avoided costs from the 2024 ACC is shown in Figure 1. This figure shows the electric GHG Adder plus Cap-and-Trade value (without GHG Rebalancing) and the GHG value from the gas model. Figure 1 also shows the high societal cost of carbon value used in the Societal Cost Test (SCT) version of the ACC, which is discussed in Section 2.2.3.

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[2] See Section 5.4.2 of the [2024 ACC Documentation] for additional details on GHG Rebalancing avoided costs.

[3] California Building Decarbonization Assessment. 2021. Available at: https://www.energy.ca.gov/publications/2021/california-building-decarbonization-assessment. Figure 15, p. 56

[4] The CEC report calculates the $114/tonne GHG abatement cost using the total discounted net costs divided by cumulative avoided GHG emissions from 2020-2045. This is different than the methodology used to determine the electric GHG avoided costs calculated in RESOLVE, which is based on the annualized cost divided by total emissions each year. Given that this is an interim value, the alignment of methodology to calculate these two values will be addressed in future CPUC proceedings.

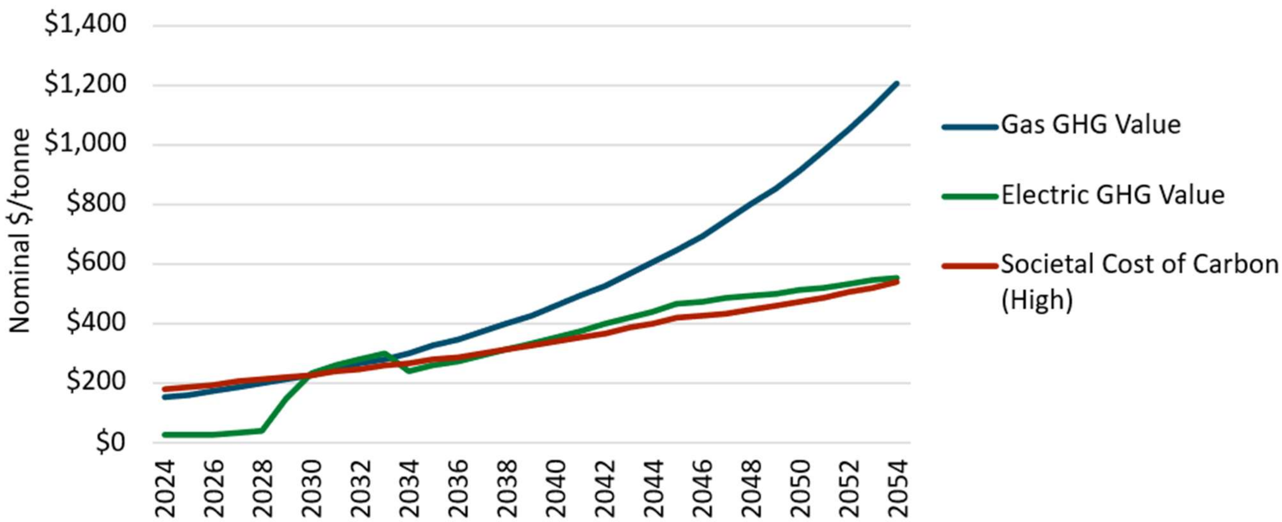

Figure 1: Comparison of GHG avoided costs in the 2024 ACC.

2.2 Proposed changes to GHG valuation in the Avoided Cost Calculator

Staff propose the following three changes to the representation of GHG value in the ACC:

1. Apply a single value to GHG emission reductions.
2. Remove the GHG Rebalancing component.
3. Cap total GHG value at the societal cost of carbon.

Staff recommend these changes be implemented together to ensure that the ACC represents a consistent, policy-aligned GHG value. These proposed changes are discussed in detail below.

2.2.1 Apply a single value to GHG emission reductions

As discussed above, California's climate policy is implemented through sector-specific planning frameworks rather than a single, economy-wide carbon price. The state therefore lacks a consistent cross-sector basis for valuing GHG reductions. In addition, sector-specific modeling of marginal abatement costs for the natural gas sector has not yet been developed beyond the current interim value. The ACC proceeding itself is not the correct venue to determine this value.

Given these limitations, staff propose to apply the electric-sector GHG value to all GHG reductions in the ACC model, including in both electric and gas models. This value is aligned with the marginal GHG value indicated by the IRP, which is the state's most robust and transparent modeling process that analyzes the cost to meet specified GHG reduction goals. Using this single value provides a coherent basis for evaluating emissions reductions across the electric and gas sectors and better reflects the state's objective of achieving net zero by 2045 across all sectors. More broadly, it provides a consistent price signal for DER investment by treating GHG reductions equally regardless of whether they occur in the electric or gas sector.

Using the electric-sector GHG value as the cross-sector proxy also ensures that any changes to the electric-sector GHG target are applied consistently. A lower electric-sector GHG value would likewise signal a lower willingness to pay for GHG reductions in other sectors, under the assumption that the revised target reflects more cost-effective abatement opportunities outside the electric system. This maintains internal coherence between sector-specific planning judgments and the GHG values applied in the ACC.

2.2.2 Remove the GHG Rebalancing component

In conjunction with applying a consistent GHG value across electric and gas models, staff also propose to remove the GHG Rebalancing component.

With the proposed transition to the use of a single GHG value across both the electric and gas ACC models, the original rationale for the GHG Rebalancing component is no longer present. As noted earlier, the GHG Rebalancing step was introduced as a reasonable method for accounting for the cross-sector implications of electrification, at a time when the electric and gas ACC models relied on separate GHG values.

Under the new proposed framework, a single GHG value is applied to all GHG reductions in the ACC, regardless of whether they occur in the electric or gas sectors. In this context, applying the electric-sector GHG value uniformly allows the ACC to represent marginal cost signals that capture the full GHG impacts of electrification and fuel-substitution measures without an additional adjustment step.

In addition, the GHG Rebalancing component assumed that there would be a change to the electric sector GHG target in the future due to changes in load or distributed generation. Removing the GHG Rebalancing component increases consistency with the IRP by assuming the current GHG target and most recent IRP modeling. If the electric sector target does change in the future, both the IRP and ACC will be updated to reflect that change in the subsequent cycles of each proceeding.

2.2.3 Cap total GHG value at the societal cost of carbon

Finally, staff propose implementing a cap on the GHG value in both electric and gas models equal to the “high” societal cost of carbon adopted in the SCT. This represents a safeguard for ratepayers against a GHG value that exceeds the value that emissions reductions provide to society. A cap would be applied to the final GHG value (after the integrated calculation of generation capacity and GHG avoided costs in the ACC electric model). Staff expect future electric sector GHG targets to be adjusted if electric abatement costs are too high for ratepayers to bear or reductions in other sectors can be more cost-effectively achieved. Placing a cap on the GHG value within the ACC will ensure that in the time between IRP and ACC cycles, a short-term high GHG value is not being used to determine long-term DER investments. This will also reduce the volatility of the ACC GHG value from one ACC vintage to the next.

3 Refinement of the integrated calculation of generation capacity and GHG avoided costs

The 2024 ACC introduced the Integrated Calculation of GHG and Generation Capacity Avoided Costs (“Integrated Calculation”) which jointly derives these two cost components simultaneously. The underlying principle is that generation capacity and GHG avoided costs are inherently interdependent. The portfolio of resources selected through the CPUC IRP will simultaneously achieve both the state’s reliability standards and its long-term decarbonization goals.

As described in the 2024 ACC documentation, staff implemented the Integrated Calculation as an optimization problem. For supply-side resources that provide marginal GHG and generation capacity value, the optimization required that the net present value (NPV) of the energy, capacity, and GHG benefits was sufficient to offset the total cost of the resource. The model’s objective was to minimize total system costs while producing internally consistent annual generation capacity avoided costs (in $/kW-year) and GHG avoided costs (in $/tonne). The implementation included a Python-based script and a workbook that summarized key input assumptions and data sources.

While the conceptual design of the Integrated Calculation provides a sound and IRP-aligned foundation for calculating GHG and Generation Capacity value, some limitations of this approach were identified by ED, their consultants, and stakeholders.

Stakeholders noted that the implementation was not transparent because the core logic was embedded in a Python script rather than a more accessible format such as Excel. Stakeholders also expressed concerns about the “black box” nature of the optimization.

The model was also sensitive to minor inconsistencies between results produced by RESOLVE and SERVM, both of which provide key inputs to the calculations. Because the model was set up as an optimization, small changes to model inputs from RESOLVE or SERVM could lead to large, unintuitive changes in Integrated Calculation results. Finally, a single resource (solar) was often driving both GHG and generation capacity value leading to results that were set based on the bounds of the problem.[5]

Staff therefore propose the following three changes to the calculation of GHG and generation capacity avoided costs:

1. Move from an optimization-based Python model to an Excel-based calculation
2. Set GHG avoided costs equal to GHG shadow prices from RESOLVE
3. Represent resources as hybrid resources in a single equation

These proposed changes are discussed in detail below.

[5] See further explanation in Section 5.3.3 of the 2024 ACC Documentation.

3.1 Move from a Python-based optimization model to an Excel-based calculation

Staff propose implementing the Integrated Calculation in an Excel-based calculation instead of in a Python-based optimization in order to improve transparency of the modelling. The Excel workbook will clearly present all equations, inputs, and intermediate results, making it easier for stakeholders to review and audit the calculation. Moving away from an optimization model also reduces the volatility of results to minor changes or inconsistencies in inputs.

3.2 Set GHG avoided costs equal to GHG shadow prices from RESOLVE

The proposed approach retains the core concept from the 2024 ACC that for each marginal resource, the combined value of energy, capacity, and GHG components should be sufficient to cover the total cost of the resource. The terms of this relationship can be rearranged to describe, in conceptual terms, the constitution of the GHG avoided cost, which is the difference between the total costs of resources constructed to meet a GHG constraint (plus associated transmission) on the margin, less the energy and capacity value that they provide to the system. The CPUC's IRP proceeding, where optimal long-term capacity expansion modeling (in RESOLVE) is used to develop least-cost portfolios to meet the state's GHG reduction objectives, provides the most rigorous and comprehensive means to quantify that GHG avoided cost. The "shadow price" of the model's GHG constraint represents the marginal cost per metric tonne incurred by California ratepayers to achieve that level of carbon reductions in a manner that is directly linked to the model's selection of resources, their corresponding costs, and the energy and capacity value they provide to the power system.

In the 2026 ACC, staff therefore propose to set the GHG avoided cost equal to the RESOLVE shadow price. This proposed change, in addition to representing marginal resources as hybrid resources in a single equation (discussed in the next section), ensures that the simplified system represented by the Integrated Calculation is robust to inputs that do not show a system in equilibrium. Setting GHG value equal to the RESOLVE shadow price also ensures that demand-side resources evaluated with the ACC are valued equally to supply-side resources evaluated through the IRP.

In some IRP cycles, GHG shadow prices from RESOLVE modelling have been volatile, with large changes between modelling years due to the "lumpiness" of resource builds and the intertemporal dynamics of RESOLVE's perfect foresight optimization. To mitigate this volatility and provide a more stable long-term signal through the avoided costs, staff propose to use a rolling average to smooth-out inter-year volatility while maintaining the trend in GHG value indicated by RESOLVE shadow prices.

3.3 Represent marginal resources as hybrid resources in a single equation

In conjunction with exogenously setting GHG value, staff propose calculating generation capacity value in the 2026 ACC using a single equation to represent a hybrid resource. This formulation uses a single equation to directly calculate annual avoided costs for each year.

For the hybrid resource, the relationship between resource costs and avoided costs is expressed as:

$$\boldsymbol{RECC\ (n) = R_{energy}(n) + AC_{GC}(n)\ \times Q_{ELCC}(n) + AC_{GHG}(n)\ \times Q_{GHG}(n)}$$

Unknowns or Parameter	Description	Units	Source
AC_{GC}	Generation Capacity Avoided Costs	$/kW-year	To be Calculated
AC_{GHG}	GHG Avoided Costs	$/tonne	RESOLVE GHG shadow price
Q_{ELCC}	Deemed RA contribution	ELCC kW	RESOLVE output
Q_{GHG}	Marginal GHG impacts	tonne/kW-yr.	Derived via SERVM energy prices
$RECC$	Gross Real Economic Carrying Charge	$/kW-yr.	RESOLVE output
R_{energy}	Net Energy Revenues (excluding Cap-and-Invest prices)	$/kW-yr.	Derived via SERVM energy prices

The hybrid resource would be composed of marginal resources selected based on the resources built in the IRP portfolio and may change over the time horizon of the ACC. Considering the portfolio of resources from the IRP used in the 2024 ACC, this hybrid resource would be solar + 4 hour storage until 2036 and solar + 8 hour storage thereafter. The combination of resources that are included in the hybrid resource may change over time and will be based on the latest IRP or TPP modelling.

The Gross Real Economic Carrying Charge (RECC) represents the annualized cost of deferring a marginal resource investment by one year. It is calculated as the difference between the NPV of total resource costs if the resource were installed in year *n* versus year *n + 1*. In essence, RECC captures both the lifetime cost of the resource and the opportunity cost associated with delaying its installation by one year.

The RECC concept has been used in the previous ACC cycles. The 2022 ACC used the RECC of a single representative resource, a four-hour lithium-ion battery, to determine generation capacity avoided costs. For the 2026 update, we propose extending this framework to use two representative resources, which allows for the simultaneous calculation of generation capacity and GHG avoided costs.

Staff propose to impose lower bounds on both the generation capacity and GHG avoided costs, aligned with the 2024 ACC modeling. The lower bound on generation capacity avoided costs will reflect the assumed ongoing fixed Operations & Maintenance (O&M) cost of existing gas resources, which represents the cost of retaining natural gas resources for their resource adequacy value. The floor for the GHG avoided costs is set equal to the forecast for cap-and-trade allowance prices used in the IRP.

4 Refinement of hourly allocation of generation capacity value

The generation capacity avoided costs in the ACC are calculated by multiplying the annual generation capacity avoided costs, expressed in $/kW-yr, by hourly generation capacity allocation factors, which sum to one.

For the 2024 ACC, the 8,760 hourly allocation factors were derived from SERVM model outputs. Specifically, the SERVM team calculated month-hour averages of Expected Unserved Energy (EUE) for the years 2026, 2030, 2035, and 2040. EUE represents the expected quantity of unserved energy, in MWh, when system demand exceeds available generation capacity. These values are based on the IRP portfolio that is designed to achieve a system-wide Loss of Load Expectation (LOLE) of 0.1 events per year. The results for each snapshot year reflect the average system operating condition across 23 years of hydro variability, 23 weather years, and five levels of load uncertainty.

Month-hour average EUE values were converted to 8760 capacity allocation factors using temperature data as follows:

1. A load-weighted daily maximum statewide temperature was calculated using the CZ2022 TMY used in the 2022 building code cycle.
2. All hours within days on which the maximum temperature exceeded a specified temperature threshold were assigned the month-hour average EUE values from SERVM for the corresponding month..
3. Days with a maximum temperature below the threshold were assigned a value of zero.

For example, for a day in August with temperature exceeding the threshold, 6pm would be assigned the average EUE value for August at 6pm. For a day in August with the temperature below the threshold, 6pm (and every other hour of the day) would be assigned a value of 0.

Capacity allocation factors were then normalized such that they sum to one over the full year. [6]

[6] See Section 5.5 of the [2024 ACC Documentation] for additional details on hourly allocation of generation capacity avoided costs in the 2024 ACC.

For the 2026 ACC, staff propose three refinements to improve the hourly allocation of generation capacity value described in the sections below:

1. Use loss of load hours (LOLH) rather than EUE as the basis for allocation factors.
2. Use energy prices rather than temperature to identify days with high generation capacity values.
3. Represent the difference in reliability risk of weekdays versus weekends in capacity value allocation

4.1 Use loss of load hours (LOLH) rather than EUE as the basis for allocation factors

The purpose of the generation capacity avoided costs is to quantify, for each hour of the year, the reliability value associated with a marginal MWh of load reduction. In other words, the hourly allocation factors represent how much capacity contribution, or avoided loss of load risk, is provided by a unit of demand reduction in that hour.

In previous ACC cycles, EUE was used as the basis for developing these allocation factors. Because EUE measures the magnitude of unserved energy (expressed in MWh), this method inherently places greater weight on hours in which system shortfalls are larger. As a result, hours with the largest loss of load events receive higher capacity value, while hours with smaller shortfalls receive relatively little weight, regardless of their frequency. This approach tends to concentrate capacity value allocation in the hours where the magnitude of unserved energy is the largest, despite the fact that a single MWh of load reduction would result in the same reliability benefit across all hours that experience loss of load (i.e. one fewer MWh of lost load).

In recognition that a unitized load reduction during a loss-of-load event provides the same improvement to system reliability regardless of the absolute size of that event, staff propose to use loss of load hours (LOLH) as the basis for the 2026 ACC capacity allocation factors. Unlike EUE, which measures the magnitude of loss of load events, LOLH provides a measure of the frequency of such events. This refinement ensures that the capacity value derived from the ACC aligns with the principle that each avoided loss of load hour has an equivalent marginal reliability value.

4.2 Use energy prices (rather than temperature) to assign days with high generation capacity value

In the current method, the month-hour averages of generation capacity values are assigned to days with high temperatures. This approach reflects an underlying assumption that capacity constrained days are most likely to occur on hot summer days. This approach is well-grounded in historical electricity system dynamics, where the hottest days of the year were also generally the days of greatest concern for reliability.

However, as loads and resources in California continue to evolve, reliability risk is expected to shift from the hottest summer days to other parts of the year as well. In particular, recent modeling in the IRP proceeding[7] has shown that the combination of increasing winter loads due to building electrification and growing penetrations of renewables eventually causes risk to shift from summer to winter, when risk is driven by combinations of high load and low renewable output. An overview of the expected timing of this transition is shown in Figure 2.

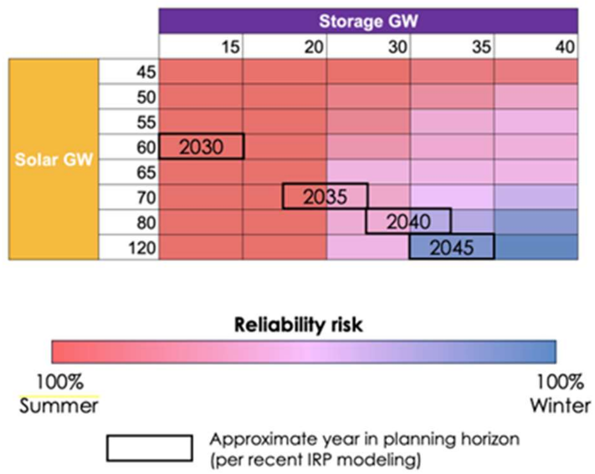

Figure 2: Changing reliability risk in California with increasing penetrations of solar and storage.

Under changing system conditions, where reliability risk is no longer confined to hot summer days, other metrics provide more useful indicators of the likely timing of loss-of-load events within the year. For the 2026 ACC, staff propose using hourly energy prices from SERVM, instead of temperature, to identify days on which the balance between supply and demand is most constrained. Energy prices capture both supply and demand dynamics and reflect when available generation is scarce relative to system needs. This approach provides a more accurate indicator of periods of system stress.

To implement the new approach, days within each month with high energy prices will be used to allocate non-zero capacity allocation hours using month-hour average outputs from reliability modeling. This method will maintain the monthly integrity of the allocation factors while assigning them to days with the highest reliability risk within the typical meteorological year represented by the ACC.

[7] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_draft_inputs_and_assumptions_public_slides.pdf

4.3 Represent the difference in reliability risk of weekdays versus weekends in capacity value allocation

As discussed in the previous section, the ACC has historically relied on high temperature days to allocate generation capacity value. Another limitation of this methodology is that it does not take into account the differences in reliability risk on weekends compared to weekdays. In contrast, several end-uses of the ACC do consider weekday/weekend differences. For example, DER profiles used in cost-effectiveness evaluation may vary across days of the week. In addition, the Net Billing Tariff (NBT), used to compensate rooftop solar customers, has export rates that are calculated from the ACC. NBT export rates are differentiated based on month, hour, and weekend versus weekday.

Reliability modeling has shown that weekdays typically have significantly higher reliability risk than weekends. In the 2026 ACC, staff propose to allocate days with non-zero reliability risk to weekends and weekdays such that the final capacity value allocation aligns with the weekend/weekday risk from reliability modeling.

5 Refinement of hourly allocation of transmission capacity value

In the ACC, annual transmission capacity values are allocated to hours of the year to allow the ACC to reflect the time-varying need for transmission capacity. The hourly allocation of transmission capacity value is calculated using peak capacity allocation factors (PCAF). These PCAFs are defined as hours that have IOU-wide net load within one standard deviation of the maximum IOU-wide net load.[8]

To calculate PCAFs, the 2024 ACC used historical (2023) system-level hourly loads from the CAISO Energy Management System dataset.[9] These historical loads were adjusted to align with the TMY represented by the ACC. The same PCAFs were applied to all years. The 2024 ACC therefore assumes that the hours of constrained transmission capacity will remain static over time

In contrast, changes in load that are shown in the IEPR load forecasts indicate that the hours of constrained transmission capacity will evolve. Staff therefore propose to update the PCAF calculations for transmission capacity allocation to use IEPR load forecasts for future years instead of historical loads. This proposed change would better represent the hours in which DERs are expected to provide transmission capacity value in the future. It will also create better alignment

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[8] See additional details of the transmission PCAF calculations in the 2024 ACC Documentation, Section 6.3.
[9] CAISO Historical EMS Load Data can be found here: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx#Historical

between transmission avoided costs and other avoided costs streams, including generation capacity, GHG, and energy avoided costs.

6 Alignment of transmission avoided cost calculations across utilities

Since the 2020 ACC update cycle, marginal transmission costs have been calculated for each IOU using either the Discounted Total Investment Method (DTIM), the Locational Net Benefits Analysis (LNBA) approach, or a combination of the two. Each of these methods, as well as the National Economic Research Associates (NERA) Regression method have been considered as approved calculation methods for transmission cost.[10] The DTIM has been applied for capacity-driven transmission investments that are categorized as system-wide, while the LNBA has been applied for individual large projects where localized load growth and associated capacity-driven investment can be readily broken out from the rest of the system. The choice of method applied has been driven primarily by the data available from each IOU.

In recent ACC update cycles, PG&E and SDG&E's transmission value has been calculated using the DTIM, though for PG&E this been superseded by the value adopted in CPUC Decision 21-11-016. Because SCE has provided costs and capacity needs for individual large projects as well as system-wide investments, SCE's transmission value has been calculated using a combination of both the DTIM and LNBA. The transmission value resulting from the combination of these methods is a weighted average $/kW-year which is applied across all of SCE's system so the locational aspect of the LNBA is not utilized.

For the 2026 ACC Update cycle, staff propose to use the DTIM method for SCE in order to align the approach across all IOUs. The capacity needs and investment associated with any large projects would be folded into the overall system-wide capacity needs and investment. This change would improve consistency in calculation across utilities and maintain the use of an approach (DTIM) that has been approved and used in recent cycles. This would also reduce volatility in transmission value tied to impacts of individual large projects lumpy transmission investments.[11]

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[10] CPUC Decision 20-03-005 considered additional proposals by parties for calculating avoided costs of transmission and declined to draw a conclusion, stating that the then current method[s] for calculating unspecified avoided transmission value would remain in place until further modification. The methods in use at the time included the DTIM and LNBA, while the NERA Regression method had been recognized as a generally approved approach but was not used.

[11] This is further supported by the minor modification made to the DTIM calculation in the 2024 ACC cycle, as described in Section 12.3.2.1 of the 2024 ACC Documentation.