

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION

**Item #20 (Rev. 1)
Agenda ID# 24510
RESOLUTION E-5476
October 8, 2026**

R E S O L U T I O N

Resolution E-5476. Adopts updates to the Avoided Cost Calculator for use in demand-side distributed energy resource cost-effectiveness analysis.

PROPOSED OUTCOME:

- Adopts certain data input updates and minor modeling adjustments for the Avoided Cost Calculator for use in Distributed Energy Resource (DER) cost-effectiveness analyses.

SAFETY CONSIDERATIONS:

- There are no safety considerations associated with this resolution.

ESTIMATED COST:

- No incremental cost. Funds necessary for updates to the Avoided Cost Calculator were authorized in Decision (D.) 16-06-007, D.23-11-087, and D.25-11-005.

Authorized by D.16-06-007, issued on June 15, 2016, D.19-05-019, issued on May 21, 2019, D.22-05-002, issued on May 5, 2022, D.24-07-015, issued on July 15, 2024, and D.24-08-007, issued on August 7, 2024.

I. SUMMARY

The Avoided Cost Calculator (ACC) is used in cost-effectiveness analysis of distributed energy resource (DERs) programs and policies. This Resolution provides a link to the final 2026 ACC and related documentation and data files, consistent with policies adopted in D.16-06-007, D.19-05-019, D.22-05-002, D.24-07-015, D.24-08-007, and D.25-11-005. The documentation provides additional detail about this update, including a comparison of the 2026 and 2024 ACC outputs. This Resolution describes the data and major modeling updates to the 2026 ACC.

II. BACKGROUND

The ACC, first adopted in D.05-04-024,¹ was originally used to only measure Energy Efficiency (EE) cost-effectiveness. The assumptions, data, and models used in the ACC require periodic updates to stay current with market conditions, prices, and trends. Thus, semi-regular improvements to the ACC modeling software and data input updates were adopted in decisions from several EE proceedings (e.g., D.06-06-063, D.09-09-047, and D.12-05-015).

The Commission subsequently expanded the use of the ACC to customer generation programs (in D.09-08-026) and to demand response programs (in D.10-12-024).

In 2014, the California Public Utilities Commission (CPUC) opened the Integrated Distributed Energy Resources (IDER) proceeding (Rulemaking (R.) 14-10-003), with a focus on developing policy to facilitate the use of Distributed Energy Resources (DERs). Among the goals of R.14-10-003 was to establish a unified cost-effectiveness framework that would apply to all DER programs, technologies, and proceedings. The IDER proceeding established a four-phase plan to accomplish this, in which the first phase was to update the ACC regularly.

In 2022, the Commission opened proceeding R.22-11-013 as a successor proceeding to R.14-10-003.² The focus of the successor proceeding is on considering DER program cost-effectiveness issues, data access and use, and equipment performance standards. Updates to the ACC were moved to this proceeding.

D.24-07-015 adopted the Societal Cost Test (SCT) as an additional informational test for the Commission to consider when evaluating the cost-effectiveness of DERs. Prior to the issuance of D.24.07-015, the Commission had adopted four cost effectiveness tests to evaluate demand-side resources programs' cost-effectiveness, which examine costs and

¹ The Commission opened R.04-04-025 to develop avoided costs in a "consistent and coordinated manner across Commission proceedings." D.05-04-024 adopted the report, Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs, and associated spreadsheet models developed by the consulting firm E3, to use in determining the cost-effectiveness of EE programs.

² [Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Use and Access, and Equipment Performance Standards](#), pp.2-3.

benefits from various perspectives, including ratepayers, the grid, program administrators and program participants. D.24-07-015 introduced the SCT – a fifth test – which considers the benefits and costs experienced by society (e.g. the impact of particulate air pollution on human health) in its evaluation of cost-effectiveness. D.24-07-015 affirmed that the Total Resource Cost Test (TRC) remains the primary cost-effectiveness test for evaluating DER cost-effectiveness and that the SCT will be information-only.³ Ultimately, the SCT will inform and supplement a broader framework of tests used for assessing the cost-effectiveness of DERs.

D.24-08-007 ordered minor modeling adjustments and data input updates to the ACC, which included:

- The ACC will use IRP's latest adopted system plan as the baseline portfolio of the ACC, replacing the "No New DER" scenario.⁴
- The ACC will use an "Integrated Calculation" methodology to model the generation capacity avoided costs and GHG avoided costs using utility solar and lithium-ion energy storage.⁵ Additional resources in the Integrated Calculation may be considered in future ACC update cycles.
- A minimum level of avoided generation capacity costs for the ACC model is set at the fixed operations and maintenance costs of existing gas generation.
- The ACC will use an alternative storage dispatch logic in SERVIM to calculate the hourly generation capacity allocation.
- The ACC will calibrate and benchmark SERVIM model outcomes for the Preferred System Plan (PSP) to actual CAISO market outcomes prior to producing the energy and ancillary service price forecasts that are used in the ACC.
- Consideration of the Refrigerant Avoided Cost Calculator (RACC) is moved to the Energy Efficiency (EE) Proceeding, R.13-11-005.
- A minimum level of avoided GHG costs for the ACC model is set at the cap-and-trade (now known as cap-and-invest) price forecasts.
- Continues using the current methodology for calculating avoided transmission and distribution costs in the ACC but with the most current transmission and distribution cost data.

³ [D.24-07-015](#), p.23-24.

⁴ [D.24-08-007](#), p.10-15.

⁵ [D.24-08-007](#), p.15-20.

D.25-11-005 made further modifications to the biennial update process for the ACC. In that decision, the Commission directed that either the IRP PSP or IRP TPP Base Case portfolio be used for the purpose of updating the ACC, among other things.⁶

D.26-09-007 ordered the following changes to the ACC, beginning with the 2026 update:

- Use a single electric-sector based value to represent both electric and natural gas greenhouse gas (GHG) reductions in the ACC.
 - Previously, the natural gas ACC model used a GHG value based on a limited 2021 study and escalated over time, which the Commission found to be increasingly outdated and inaccurate and instead directed that a single electric-sector based value be used for both natural gas and electric ACC models.
- Remove the GHG rebalancing component.
 - In previous iterations of the ACC, the GHG rebalancing component represented the effect on sectoral emissions goals due to the migration of load from natural gas to electric over time. Adopting the single avoided GHG value linked to the IRP, as described above, does not require a GHG rebalancing component because there is no longer a need for a separate adjustment to reflect cross-sector (gas to electric) value transfers. This uniformly allows the ACC to represent marginal cost signals thus capturing the full GHG impacts of electrification and fuel-substitution measures without an additional adjustment step.
- Use a simplified implementation of the Integrated Calculation to address transparency issues and sensitivity to minor inconsistencies between RESOLVE and the Strategic Energy & Risk Valuation Model (SERVM).
 - The decision adopts an updated integrated calculation that considers a hybrid solar+storage resource as a single resource rather than two separate resources.
- Use Loss of Load Hours (LOLH) rather than Expected Unserved Energy (EUE) for capacity allocation factors.
 - EUE puts more weight on large shortfall events and understates the value of resources that reduce loss of load across many hours. Using the frequency of loss of load aligns capacity avoided costs with the consistent value of avoiding loss of load in any given hour.
- Use energy prices (rather than temperature) to assign days with high generation capacity value.

⁶ [D.25-11-005](#), p.13-15.

- Assigning month-hour averages of generation capacity values to individual days from a method that uses days with the highest temperatures to days with highest energy prices more accurately identifies days with greatest grid constraints, reflecting higher building electrification uptake and growing renewable generation.
- Represent the difference in reliability risk of weekdays versus weekends in capacity value allocation.
 - Reflects the results of reliability modeling that show weekdays have significantly higher reliability risk than weekends.
- Update the peak capacity allocation factors (PCAFs) calculations for transmission avoided costs.
 - Use the Integrated Energy Policy Report load forecast for future years, as used in SERVVM modeling for calculating energy avoided costs, instead of historical loads.
- Align Transmission Avoided Costs across utilities.
 - Use the Discounted Total Investment Method approach to calculate marginal transmission costs for all electric utilities.

III. DISCUSSION

The adoption of these changes in D.26-09-007 produces higher avoided costs on average throughout the day compared to the 2024 ACC.

Increases in renewable penetration result in a lower energy value for the 2026 ACC compared to the 2024 ACC, though the GHG value increases substantially with the expiration of federal tax credits for developing renewable energy resources and tariffs on imported solar and storage components. The increase in GHG value and application of the electric GHG value to the natural gas ACC model drives an increase in overall gas ACC values as well. The comparison of GHG avoided costs between 2024 ACC and 2026 ACC can be found in the ACC documentation section 4.4.

The Generation Capacity value in the 2026 ACC is now calculated using hybrid solar-plus-storage resources. The allocation of generation capacity value has also been updated to better represent the hours when DERs could provide the highest resource adequacy value. The comparison of capacity avoided costs and allocation factors between 2024 ACC and 2026 ACC can be found in the ACC documentation section 4.4 and 4.5.

Other ACC methodology updates produce no significant effect on avoided costs relative to 2024. Using LOLH rather than EUE for capacity allocation factors, using energy prices to assign days with generation capacity value, and separating weekdays versus weekends in generation capacity value allocation will better reflect real-world results in the ACC. Updating the transmission avoided cost allocation to use the Integrated Energy Policy Report load forecast for future years spreads the transmission costs across additional seasons and hours of the day later in the horizon but does not impact the overall magnitude of the costs. Aligning the calculation of transmission avoided costs across utilities under the DTIM method results in only a minor shift in the transmission values.

Table 1 lays out the combined effect of the expected changes relative to 2024:

Table 1

Direction of Change Driven by Methodological Updates to Avoided Cost Calculator relative to 2024 ACC	
Gas GHG Value	Increase
GHG Rebalancing Removal	Increase
Electric GHG Value	Increase
Refined Integrated Calculation of Generation Capacity Value	Change varies by year
Use LOLH rather than EUE	Allocation factors are more evenly spread across hours
Use energy prices (rather than temperature) to assign days with high generation capacity value.	Generation capacity avoided costs occur in both winter and summer months, rather than only in summer months
Separate weekdays versus weekends in generation capacity value allocation	Generation capacity avoided costs are allocated to weekdays only
Update the peak capacity allocation factors (PCAFs) calculations for transmission avoided costs.	Spreads value into additional hours and months in later years; no change in overall magnitude
Alignment of Transmission Avoided Costs across utilities (DTIM method)	No significant change

IV. COMMENTS

Public Utilities Code section 311(g)(1) provides that this Resolution must be served on all parties and subject to at least 30 days public review. Any comments are due within 20 days of the date of its mailing and publication on the CPUC's website and in accordance with any instructions accompanying the notice. Section 311(g)(2) provides that this 30-day review period and 20-day comment period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day review and 20-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the CPUC's agenda no earlier than 30 days from the date of mailing.

Opening comments were received on September 24, 2026, from the California Large Energy Consumers Association (CLECA), Pacific Gas and Electric Company (PG&E), the Solar Energy Industries Association (SEIA), Southern California Edison Company (SCE), and Southern California Gas Company (SoCalGas). Reply Comments were received on September 29, 2026, from PG&E, SEIA, and SCE. Comments are summarized in non-italics below and the Commission's Energy Division's response to comments are in italics below.

California Large Energy Consumers Association (CLECA)

CLECA contends that the draft Resolution misrepresents the volatility of generation capacity avoided costs, stating that costs fall 85 percent from 2026 to 2027, rise 308 percent in 2028, fall 74 percent in 2029, and increase 744 percent between 2040 and 2045. CLECA contends that these swings persist even with the floor binding in most years from 2027 through 2040 and argues that absent the floor, volatility would be greater, indicating model instability. CLECA further states that because the Resolution adopts the 2026 ACC v1a and presents generation capacity results only in Figure 2, that figure should be corrected before adoption.

Energy Division acknowledges the Draft Resolution Figure 2 misrepresented capacity avoided costs. The comparison of capacity avoided costs and allocation factors between 2024 ACC and 2026 ACC can be found in the ACC documentation section 4.4 and 4.5.

CLECA argues that in thirteen of the fifteen years from 2026 through 2040, the reported generation capacity value equals the floor and sits about 39 percent below what CLECA

contends is the corrected floor reflecting the fixed cost of retaining an existing gas unit. CLECA states that while D.26-09-007 acknowledged the omission, it declined to correct it to align with IRP assumptions; however, CLECA argues this left capacity values roughly 39 percent too low in most years. CLECA recommends correcting the floor to include taxes and insurance in the 2028 update and further recommends that Energy Division publish the Integrated Calculation results before applying the floor.

Energy Division may consider this concept for the next ACC cycle, and notes that D.26-09-007 did not adjust the price floor for this ACC update.

CLECA contends that the Integrated Calculation proposed in the draft Resolution is narrower than what the Commission approved two years ago. CLECA further contends that the Revised Staff Proposal is less technology-agnostic, effectively limiting the calculation to a single hybrid resource. CLECA recommends that, in the 2028 ACC update, the Commission direct Energy Division to expand the Integrated Calculation to include the resource types relied upon in the adopted IRP portfolio, including demand response resources essential for reliability.

Energy Division confirms that given the GHG avoided costs have been determined, only one equation is needed to calculate generation capacity avoided costs since it is only unknown quantity. With one equation needed to calculate the unknown quantity, using hybrid solar and storage is more appropriate than using either resource, since both are economically selected in the TPP portfolio throughout the planning horizon and often complement each other.

Energy Division clarifies that in the 2026 ACC, the GHG avoided cost is set equal to the RESOLVE GHG shadow price, leaving the generation capacity avoided cost as the only unknown in the Integrated Calculation. Solving for a single unknown requires a single cost-recovery equation, and therefore a single representative resource. Adding further resources would over-determine the calculation, because one capacity value cannot generally satisfy multiple resources' cost-recovery conditions at the same time. Given that one resource is needed, a solar-plus-storage hybrid is more appropriate than either standalone resource. Solar and storage are both economically selected in the 2026-2027 TPP portfolio throughout the planning horizon, and the hybrid represents the combined value of these marginal additions. RESOLVE does not select new demand response resources in the 2026-2027 TPP portfolio. Existing demand response is reflected in the baseline resource portfolio but does not represent a marginal resource, and therefore is not appropriate to include in the Integrated Calculation.

CLECA contends that D.26-09-007 declined to cap the GHG value at the high societal cost of carbon used in the Societal Cost Test, which CLECA notes corresponds to the

95th-percentile climate-damage estimate at a three-percent discount rate. CLECA states that the ACC's GHG value exceeds this threshold in nineteen of the twenty years from 2026 through 2045, by more than 50 percent in eleven years and more than 100 percent in five, peaking at 131 percent above it in 2031. CLECA argues that these results warrant further review in the 2028 ACC update, including whether a cap on GHG avoided costs is appropriate.

Energy Division may take this concept into consideration for the next ACC cycle. D.26-09-007 notes that Energy Division may reconsider capping GHG avoided costs in future ACCs if the RESOLVE model's GHG shadow prices become persistently high and unrealistic in the future.

CLECA contends that avoided GHG quantities are based on an implied marginal heat rate derived by dividing each hour's energy price by the gas price, subject to an upper bound but no lower bound. CLECA contends that this method treats gas generation as marginal in all hours, including hours when no gas unit could be marginal. CLECA states that at the September 9, 2026, workshop it asked whether SERVM marginal-resource data could refine these hourly heat rates, and CLECA notes that Energy Division responded that SERVM is not yet precise enough. CLECA therefore recommends that, in the 2028 update, the Commission direct Energy Division to improve SERVM precision to identify hourly marginal resources and produce more realistic avoided-emissions rates.

Energy Division agrees it may be necessary for the avoided-GHG methodology to continue to evolve as the CAISO resource mix changes. SERVM provides a strong representation of marginal system conditions, particularly during periods when gas generation would be expected to be on the margin. The remaining differences are concentrated in a more limited set of operating conditions, including some low-net-load hours where historical CAISO operations and SERVM differ in the relative dispatch of storage and combustion turbines.

Using SERVM to assign a single marginal resource in every hour would not necessarily produce a more accurate avoided-emissions estimate. The marginal response to an incremental change in load can involve multiple resources and operational effects, including storage charging and discharging, imports, renewable curtailment, unit commitment, and ancillary-service positioning. As a result, the resource dispatched at the margin in a production-cost simulation does not always translate directly into a single hourly avoided-emissions rate. The implied marginal heat-rate analysis is also useful for analyzing pricing patterns and the reasonableness of pricing, rather than directly identifying emissions rates. Market prices can reflect factors such as congestion and opportunity costs that are not directly related to the fuel mix in a given hour.

Energy Division agrees, however, that SERVVM dispatch information can provide additional information for evaluating and refining the current implied marginal heat-rate methodology. SERVVM also tracks emissions directly, providing additional information that can be analyzed alongside the emissions implied through pricing. Future ACC cycles may continue to reconcile modeled and historical dispatch, review additional historical years as data become available, and evaluate the relationship among marginal prices, resource dispatch, and avoided emissions across a broader range of system conditions.

CLECA contends that the Draft Resolution states the 2026 ACC spreads generation capacity value overnight to cover storage-dispatch hours rather than concentrating it in peak nighttime hours, and CLECA contends that the Resolution separately reports that updates to hourly allocation produce “no significant change.” CLECA notes, however, that ACC workpapers show many more hours are needed to capture a day’s capacity value. CLECA argues that this dispersion may be significant for limited-duration resources such as batteries and may call into question whether 4-hour or 8-hour storage aligns with multi-hour daily capacity needs. CLECA states that while it does not dispute the new distribution, the effect warrants greater visibility than described, and CLECA recommends that the Commission require reporting of this dispersion in the 2028 ACC.

Differences between SERVVM and historical CAISO dispatch do not automatically indicate a modeling error. Historical dispatch reflects the resource mix and operating conditions that existed in the backtest year, while future ACC cases include substantially greater storage capability. Historical dispatch is also not necessarily indicative of future CAISO market dispatch, which may evolve as storage and solar penetration increase substantially. As storage penetration increases, batteries are expected to play a larger role in charging during low-net-load periods and discharging during higher-value periods. This changes which resources respond to incremental changes in load and makes the hourly marginal system response more complex than identifying a single gas resource as marginal.

Pacific Gas and Electric Company (PG&E)

PG&E contends that the Generation Capacity tab contains a potential inconsistency between the scenario-selection dropdown and the CHOOSE() formula that implements it. PG&E notes that the dropdown labels Option 1 as TRC, Option 2 as the Societal Cost of Carbon – Base case, and Option 3 as the Societal Cost of Carbon – High case, but PG&E contends that the formula appears to assign the High case to Option 2 and the Base case to Option 3. PG&E therefore requests that Energy Division review the formula

to confirm the intended mapping and recommends revising it if the current implementation is unintentional.

Energy Division confirms this inconsistency, and it has been addressed in the updated draft ACC Electric Model v1b.

PG&E requests additional documentation explaining how resource costs are derived in the Integrated Calculation. PG&E further recommends that staff provide clear references linking published inputs to their underlying source files to support stakeholder review and verification.

Energy Division confirms resource costs are derived from the CPUC Pro Forma for 26-27 TPP.⁷ Storage cost is equal to levelized Fixed Cost for Li-ion Battery (4-hr/8-hr) – CA. SCE Eastern Solar is selected to represent the median solar cost given the range of solar costs in the pro forma.

The underlying inputs for energy revenues and emission contribution can be found in the SERVM Hourly Values workbook, “Real Energy wo Carbon” and “Emission Rate” tabs.

Energy Division will not be producing new workbooks at this time.

In its Reply Comments, PG&E agrees with parties that the magnitude and growing importance of the GHG value in the ACC warrants continued attention in future updates and reiterates its recommendation that the Commission rely on the California Air Resources Board Scoping Plan as the basis for evaluating GHG valuation assumptions. PG&E argues that a Scoping Plan-based framework would better connect ACC values to the State’s decarbonization strategy and improve transparency in how GHG values are developed. PG&E also recommends coordination with CARB to create a transparent and durable approach for identifying appropriate GHG valuation benchmarks.

Energy Division notes the Commission resolved the question of whether to cap GHG values in the 2026 update D.26-09-007. Energy Division may reconsider capping GHG avoided costs in the ACC if the RESOLVE model’s GHG shadow prices become persistently high and unrealistic in the future.

⁷Available at [RESOLVE Upstream Data Workbooks and Public Case Results Viewers](#)

PG&E contends that stakeholders continue to face challenges validating ACC calculations and contends that greater transparency on inputs, assumptions, and methods is needed. PG&E argues that such transparency would improve stakeholder review and strengthen confidence in future ACC updates.

Energy Division may consider this concept in future ACC updates.

Solar Energy Industries Association (SEIA)

In its Opening Comments, SEIA contends that Figure 2 in Draft Resolution E-5476 does not reflect the correct IC model results and contends that the proper figure appears on the IC model's "Result Summary" tab.

Energy Division notes the comparison of capacity avoided costs and allocation factors between 2024 ACC and 2026 ACC can be found in the ACC documentation section 4.4 and 4.5.

In its Opening Comments, SEIA contends that the IC assumes a hybrid solar-plus-storage unit with equal solar and storage capacities, assigning ELCC values of 5 percent for solar and 35 percent for 4-hour storage in 2026. SEIA contends that the IC erroneously adds these ELCCs to produce a 40-percent hybrid ELCC. SEIA argues that the correct contribution is the average of the two values - 20 percent - because a 100-MW hybrid resource composed of 50 MW of solar and 50 MW of storage would provide 20 MW of effective capacity, not 40 MW. SEIA therefore contends that the IC mistakenly assumes a 40-MW contribution for a 100-MW hybrid resource.

Energy Division's Integrated Calculation (IC) characterizes the marginal hybrid resource on a per-unit basis, where one unit consists of 1 kW of solar paired with 1 kW of storage, rather than per kW of combined nameplate capacity. The levelized fixed cost of the hybrid resource in the Integrated Calculation is calculated as the sum of the levelized fixed costs of 1 kW of solar and 1 kW of storage. Under this definition, the capacity contribution per unit is the sum of the component ELCCs. Averaging the ELCCs would be appropriate only if costs were expressed per kW of combined nameplate.

In its Opening Comments, SEIA notes that an important IC input is the assumed energy rents that solar and storage units will earn in the CAISO market and argues that the storage rent calculations are unrealistic because real-world storage cannot operate with perfect foresight of future prices. SEIA states that CAISO has documented gaps between actual storage revenues and theoretical maximums in recent market performance

reports and recommends reducing the modeled storage energy rents by 14 percent to reflect how storage units actually operate in the CAISO market.

Energy Division maintains the Integrated Calculation is intended to derive avoided costs that are internally consistent with the energy avoided costs published in the ACC. In the Integrated Calculation, the generation capacity value is derived from the residual net cost of the marginal resource after accounting for its energy revenues and GHG contribution. Discounting modeled storage energy revenues would therefore increase the capacity value. At the same time, DERs evaluated using the ACC are credited with the full hourly energy avoided cost, without a comparable forecast-error discount. Applying the discount only within the Integrated Calculation would create an asymmetry in which the marginal resource's energy value is understated while the DER's energy value is not.

In its Opening Comments, SEIA notes that the 2026 ACC relies on the IRP base-case portfolio adopted in D.26-02-057 and contends that this portfolio shows a major shift from 2028 to 2031 in storage duration, with additions of 4-hour storage nearly ending after 2028 and a 9-GW tranche of 8-hour storage entering from 2029–2031, even though SEIA notes that the IRP does not specify timing within that period because 2029 and 2030 are not explicitly modeled. SEIA states that it raised this transition in the 2026 ACC proceeding and that D.26-09-007 adopted its proposal to align with the IRP. SEIA further contends that the IC assigns avoided-capacity values for each of these years and shows that 8-hour storage declines from roughly \$300 per kW-year in 2029 and 2030 to the \$49 per kW-year floor in 2031, producing an average value of \$213 per kW-year for the tranche. SEIA argues that the draft 2026 ACC instead applies only the 2031 floor value to the entire tranche, despite IC results demonstrating much higher values. SEIA contends that D.26-09-007 directed the use of 2031 solely to align with the IRP and states that, because the IRP treats 2031 additions as representing cumulative additions across 2029–2031, consistency requires using the IC average of \$213 per kW-year. SEIA argues that relying only on the floor value would misalign the ACC with the IRP and undervalue the first major tranche of 8-hour storage.

Energy Division maintains the avoided generation capacity cost represents the lowest cost of providing resource adequacy value given the resource portfolio. Based on the SERVM and IRP inputs, the solar-plus-4hr-storage is the lower-cost resource prior to 2031, while the solar-plus-8hr-storage is the lower-cost resource beginning in 2031. The higher 8-hour storage values in 2029 and 2030 therefore do not represent the avoided cost in those years. The 2031 transition is

also consistent with the Mid-Term Reliability procurement order in which the deadline to procure 8-hour storage has been extended to 2031.⁸

In its Opening Comments, SEIA argues that the draft 2026 ACC adopts a new post-processing method for SERVM results that effectively eliminates all energy-price increments above a 12,500 Btu/kWh market heat rate, including the scarcity adjustment SEIA contends is necessary to reflect realistic CAISO market prices. SEIA explains that scarcity adjustments are added to raw SERVM results during benchmarking to align them with actual market outcomes and to account for production-cost models' inability to simulate scarcity premiums, and SEIA argues that these adjustments should remain even when removing GHG Cap-and-Trade (C&T) costs. SEIA claims that the draft ACC's process caps the implied market heat rate (IMHR) at 12,500 Btu/kWh when stripping out the C&T component and that reconverting the IMHR back to an energy price retains this cap, thereby eliminating scarcity adjustments in high-demand hours. SEIA notes that the 2024 ACC did not cap energy prices in this way, as the IMHR cap applied only to the C&T value, which preserved scarcity pricing. SEIA agrees that removing the C&T value and using a capped heat rate for that purpose is appropriate but argues that the remainder of the SERVM energy price should not be suppressed to the capped level when scarcity is present. SEIA contends that the draft methodology imposes an unrealistic ceiling on avoided energy costs by removing scarcity adjustments that have been part of previous ACC versions.

Energy Division has incorporated the scarcity adjustment in the energy avoided costs. This update will impact storage energy revenues and generation capacity avoided costs. New values are reflected in ACC v1b workbooks.

In its Opening Comments, SEIA argues that benchmarking results presented at the September workshop show that SERVM understates CAISO energy prices in the 20 percent of hours with the lowest net loads, which SEIA notes often occur during midday solar-production hours. SEIA contends that SERVM produces too many zero-price hours and an overly sharp price drop at the 20th-percentile threshold, substantially understating the energy value of distributed solar resources. SEIA therefore recommends that Energy Division adjust NP-15 prices in the lowest 20 percent of hours so the forecast more closely matches recent market results.

⁸ D.24-02-047, Decision Adopting Preferred System Plan and Related Matters, and Addressing Two Petitions for Modification, R.20-05-003, February 20, 2024, OP 17 at 140, available at <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K918/525918033.PDF>.

Energy Division may continue refining the hourly avoided-GHG methodology and expanding the use of SERVVM dispatch information as additional historical benchmarking becomes available and system conditions evolve.

Energy Division agrees that the 2022 backtest shows a difference between SERVVM and observed CAISO prices in approximately the lowest 20 percent of net-load hours. However, this difference alone does not support adjusting future NP-15 prices upward to reproduce the historical 2022 price relationship.

Across most of the net-load distribution, SERVVM reasonably represents the relationship between net load and market prices. In the lowest-net-load hours, the price difference is accompanied by an important dispatch difference: historical CAISO operations relied on more combustion-turbine generation during many of these hours, while SERVVM utilized storage more actively and relied less on thermal generation.

Historical CAISO prices also reflect market bidding behavior, self-scheduling, opportunity cost bidding, congestion, unit-commitment decisions, ancillary-service positioning, and other operational and market practices that a production-cost model does not reproduce exactly. These factors may contribute to observed CAISO prices remaining positive during some low-net-load conditions.

Energy Division acknowledges the future electric system is materially different from the 2022 system. Future years include substantially more storage and renewable generation, along with changes in thermal commitment, curtailment, imports, and overall system flexibility. Greater storage penetration is expected to increase charging during solar-rich, low-net-load periods and discharging during higher-value periods, changing both dispatch patterns and price formation relative to the historical system.

For these reasons, the 2022 backtest does not provide a sufficient basis for imposing the historical price shape on future NP-15 prices through an exogenous adjustment. The forecast should continue to reflect the economics and dispatch of the future system represented in SERVVM rather than mechanically reproducing historical prices. Backtesting is useful to align when we can, but we also realize it is imperfect in that we cannot assume the current CAISO market dynamics perfectly continue into the future.

In its Opening Comments, SEIA argues that the draft 2026 ACC continues to rely on PG&E's DTIM-based marginal transmission capacity cost of \$53.98 per kW-year adopted in D.21-11-016 nearly five years ago and contends that this value, used in the

2022 and 2024 ACCs, must be updated. SEIA submits that the 2026 ACC should instead adopt the lowest PG&E MTCC proposed in A.24-09-014 - PG&E's recommended DTIM-based value of \$63.61 per kW-year - and notes that the Commission has previously allowed IOU-proposed Phase 2 marginal-cost values to be used in the ACC even when not yet approved. SEIA states that Commission-approved values are preferable but argues that, given delays in PG&E's current GRC Phase 2 proceeding, relying on the more recent DTIM calculation from A.24-09-014 is preferable.

Energy Division considers the use of PG&E's proposed MTCC value of \$63.61 per kW-year to be a reasonable modification to the PG&E transmission value for the 2026 ACC update. This is included in the 2026 ACC Electric Model v1b and accompanying documentation.

In its Opening Comments, SEIA argues that recent MTCC history on PG&E's system demonstrates the value of reviewing and, if necessary, litigating MTCC calculations in GRC Phase 2 proceedings where IOU marginal costs are set. SEIA notes that it and PG&E have agreed on the transmission projects to include in PG&E's updated DTIM-based MTCC calculation in A.24-09-014, and SEIA recommends applying the same criteria and supporting showings to SCE's and SDG&E's DTIM calculations for avoided transmission costs.

Energy Division appreciates stakeholder efforts to improve transparency and find alignment on the determination of marginal transmission costs. Energy Division will consider stakeholder suggestions to improve utility project selection criteria and overall transmission avoided cost methodology in future ACC updates.

In its Opening Comments, SEIA contends that, unlike PG&E, it is unclear why SCE selected the limited set of transmission projects used in its DTIM calculation and contends that SCE does not propose a MTCC in its GRC Phase 2 proceedings. SEIA argues that neither the draft 2026 ACC documentation nor the draft Resolution addresses this issue and contends that Energy Division has not released SCE's response to the data request on deferrable transmission projects. SEIA submits that, absent a transparent showing of why reliability projects are excluded, all CAISO-approved reliability projects should be included in the MTCC calculation used in the ACC. SEIA therefore asks that SCE be directed to recalculate its avoided transmission costs using the projects listed in Table 2 of SEIA's opening comments.

The established ACC methodology for considering transmission projects as potentially deferrable or avoidable prioritizes those which are primarily driven by capacity-related needs. While the Transmission and Distribution Avoided Cost Studies or other efforts may allow for further

precision in determining which projects are deferrable, defaulting to the inclusion of all reliability-related transmission projects, including those which may not be avoidable by DERs, would be inappropriate and would be expected to result in over-estimation of the transmission value in the ACC. As noted by an SCE representative during the 2026 Draft ACC workshop, the 2026 ACC Documentation does include the substantive portions of SCE's response to the 2026 ACC data request. Energy Division will consider stakeholder suggestions to improve utility project selection criteria and overall transmission avoided cost methodology in future ACC updates.

SEIA argues that if the Commission decides to accept the limited number of SCE reliability-related projects used in the draft 2026 ACC, that the Commission not allow the removal of the Wildlife substation project from the calculation. SEIA states that during the workshop on the draft 2026 ACC, SCE clarified that Wildlife is a load-related project, but that it had removed the project on the grounds it principally serves a wholesale transmission customer of SCE and that its inclusion in the 2024 ACC calculation was a mistake. SEIA disagrees with this removal of Wildlife and asks that the Commission reinclude it in the calculation.

Energy Division finds merit in SCE's reasoning for removing the Wildlife substation from inclusion in the transmission avoided cost calculations, given that the substation and associated transmission investments do not directly serve SCE retail customers. DERs that fall under the purview of the ACC would not be able to avoid or defer transmission costs associated with the Wildlife substation.

In its Reply Comments, SEIA argues that the Commission should reject SCE's request to revise the draft 2026 ACC using different natural-gas and GHG-allowance price forecasts, contending that similar requests have been rejected in prior ACC cycles and that SCE understates the extent of changes that would be required if new forecasts were adopted.

Energy Division rejects SCE's request, and the reasoning for which can be found on Pg. 18.

Southern California Edison Company (SCE)

In its Opening Comments, SCE recommends updating the natural-gas and Cap-and-Invest allowance price forecasts in the 2026 ACC to those developed for the CEC's 2025 IEPR, noting that the draft ACC currently relies on older assumptions from the 2026–2027 TPP portfolio based on a 2023 CEC forecast. SCE argues that the older forecast is now outdated and materially higher than recent market prices and the

subsequent 2025 IEPR values, and SCE recommends substituting the most recent IEPR forecasts and, if a SERVIM rerun is infeasible, reconstructing energy prices using the implied market heat rates already developed for the draft ACC. SCE further states that the Commission should retain the 2026–2027 TPP portfolio as the ACC baseline while updating the gas and allowance price assumptions to the 2025 IEPR forecast, arguing that this narrow adjustment preserves IRP-selected resources, maintains CEC’s role as the authoritative source of gas and allowance price forecasts, and improves accuracy in translating gas-market conditions into avoided wholesale-energy value.

Energy Division clarifies that the natural gas and allowance price assumptions are inputs to the IRP modeling that produced the 2026-2027 TPP portfolio, and they are linked to other components of the ACC. In RESOLVE, the GHG shadow price represents the marginal cost of meeting the GHG planning target beyond the emission reductions driven by the Cap-and-Invest program. The two values are therefore interdependent: a change in the allowance price changes the incremental cost reflected in the GHG shadow price. Updating the allowance price alone, without re-deriving the GHG shadow price, would produce an internally inconsistent GHG value.

Similarly, under the Integrated Calculation, energy prices determine the energy revenues earned by the marginal resources. Lower gas and allowance prices would reduce these revenues, which in turn would increase the capacity values needed for the marginal resources to recover their costs. To maintain consistency across all value streams and with the IRP, the 2026 ACC retains the natural gas and allowance price forecasts underlying the 2026-2027 TPP portfolio.

SCE states that the Draft Resolution appears to apply the IRP GHG shadow prices directly without the smoothing methodology proposed by Energy Division Staff in the Revised Staff Proposal. SCE argues that this is inconsistent with the methodology adopted in Decision (D.) 26-09-007.

Energy Division maintains the smoothing was proposed as a means to address inter-year volatility, not as an independent adjustment to the RESOLVE shadow prices. With the current inputs, the primary effect of smoothing would occur in the near-term. Smoothing would increase the 2026 GHG adder and decrease the 2026 generation capacity avoided cost, while increasing the generation capacity avoided cost in 2028. Stakeholders can review this impact by editing the GHG Shadow Price Smoothing cell in the Integrated Calculation workbook. Because the Integrated Calculation solves for the GHG and capacity values jointly, smoothing the GHG value largely shifts value between avoided cost components and across years rather than changing the overall avoided cost. Given the current inputs, retaining the unsmoothed RESOLVE shadow prices is reasonable. Energy Division agrees that the smoothing methodology

should be applied in future ACC updates if the RESOLVE shadow prices exhibit material inter-year volatility.

In its Opening Comments, SCE states that the draft documentation incorrectly reports that SCE claimed the Wildlife substation is “not in fact capacity related,” and SCE clarifies that it made no such claim. SCE argues instead that it excluded the project because, although the substation is a capacity addition, the additional capacity is driven by load growth from Riverside Public Utilities (RPU), not SCE’s retail customers. SCE notes that under normal operating conditions the Wildlife substation will serve only RPU and argues that the ACC should not include the project’s cost because DER programs evaluated by the ACC cannot be offered to RPU’s customers.

Energy Division agrees with SCE’s stated rationale for excluding the Wildlife substation and has revised the 2026 ACC documentation accordingly.

In its Opening Comments, SCE notes that the draft 2026 ACC Documentation would set SCE’s long-term distribution marginal cost at \$210.38/kW-year - more than double SDG&E’s and triple PG&E’s - and SCE acknowledges that the Resolution is not the proper vehicle for revising the underlying methodology. SCE argues, however, that the substantial variation in IOU long-term marginal distribution costs reinforces the need to address these issues through the ongoing Transmission and Distribution Avoided Cost Studies or through potential review in the Commission’s Advanced Electric Rate Design Rulemaking (R.26-04-009). SCE further argues that the size of these differences underscores the need for method revisions to ensure that SCE’s customers are not overpaying for benefits unlikely to materialize.

Energy Division notes that the ongoing Transmission and Distribution Avoided Cost Studies have not been completed or released at this time.

In its Reply Comments, SCE agrees with SoCalGas and CLECA that the draft 2026 ACC results highlight the need for process improvements in how IRP outputs are incorporated into the ACC. SCE argues that while it supports aligning the ACC with the Commission’s IRP framework, parties must be able to review actual IRP results - and the resulting ACC values - before the methodology is finalized. SCE therefore urges the Commission to adopt an ACC process that ensures parties can evaluate proposed methodologies using the appropriate IRP portfolio, or at least a draft of it.

Energy Division notes that this resolution is not the appropriate venue to propose changes to the biennial update process.

Southern California Gas Company (SoCalGas)

In its Opening Comments, SoCalGas states that it supported the provision in D.26-09-007 retiring the gas-specific interim value derived from a limited 2021 CEC study in favor of aligning the gas value with the electric-sector RESOLVE shadow price, but SoCalGas argues that the actual gas-sector values resulting from this change were not transparently presented until now. SoCalGas contends that the magnitude of the change underscores the need to actively refine the methodology so it accurately reflects avoided GHG emissions costs and further contends that the increase and volatility of the 2026 GHG adder highlight that a single input now drives most avoided-cost value across fuels. SoCalGas argues that it does not support capping GHG values, asserting that a cap would not improve accuracy and would merely tie the TRC's GHG cost to the Social Cost of Carbon. SoCalGas also states that the Draft Resolution's own outputs show what "persistently high and unrealistic" could look like, which it views as an accuracy issue rather than justification for a ceiling. Due to these concerns, SoCalGas recommends that the Commission direct Energy Division to make GHG valuation - including the electric shadow-price methodology and development of a gas-specific adder - the leading priority for the next ACC update and begin this work well in advance of the update cycle.

Energy Division may consider this concept the next ACC cycle.

In their Opening Comments, SoCalGas recommends that the Commission examine how the ACC determines the value of carbon for the Societal Cost Test (SCT) and notes that neither the documentation nor any Commission decision identified by SoCalGas explains why using the Social Cost of Carbon as a floor, rather than presenting it on its own terms, is appropriate for SCT valuation. SoCalGas contends that the 2026 ACC GHG values make that floor irrelevant because the SCC Base scenario never exceeds the TRC GHG value from 2025 through 2055 and the SCC High scenario does so only in 2025 and 2026, which occur before Energy Efficiency programs are expected to begin screening against the 2026 ACC. SoCalGas argues that this floor design was never justified on the record and recommends that the Commission direct Energy Division either to justify the design with stakeholder agreement or remove it from SCT GHG valuation.

Energy Division does not agree that the SCT floor should be removed. The Standard Practice Manual (SPM) describes the Societal Test as a variant of the TRC that "utilizes essentially the same input variables as the TRC Test, but they are defined with a broader societal point of view,"

and notes that it may use "higher marginal costs than the TRC test."⁹Setting the SCT GHG value at the greater of the TRC GHG value (i.e., the IRP GHG shadow price) and the SCC means that the SCT does not value avoided carbon below the TRC. A lower GHG value in SCT would contradict the SPM's broader societal perspective. Energy Division acknowledges that the U.S. Environmental Protection Agency's (EPA) 2023 Report on the Social Cost of Greenhouse Gases estimates higher SCC values than those currently used in the ACC. Staff may recommend an updated SCC source in a future ACC cycle.¹⁰

V. FINDINGS AND CONCLUSIONS

1. D.22-05-002 OP 1 directs Energy Division Staff to make major changes to the Avoided Cost Calculator, as specified in that Decision, during even-numbered years.
2. D.22-05-022 provided additional time for review of the draft Avoided Cost Calculator.
3. D.24-08-007 directed Energy Division Staff to hold a workshop to review the current procedural framework for the ACC biennial update process, facilitate discussion of the ACC Guiding Principles, and how to consider equity in the evaluation of DER cost-effectiveness.
4. Energy Division Staff held the workshop, as directed in D.24-08-007, on April 10, 2025, and gave stakeholders the opportunity to present and comment on proposed Guiding Principles for the ACC, equity considerations in the evaluation of DER cost-effectiveness, and changes to the biennial update process.
5. D.25-11-005 replaced the biennial ACC update process in D.22-05-002 with a revised process to avoid delays in ACC updates.
6. D.26-09-007 adopts minor modeling adjustments and data input updates to the ACC.
7. The updates to the Avoided Cost Calculator, as referenced in Appendix A, are reasonable for use in DER cost-effectiveness. It is reasonable to adopt this 2026 Avoided Cost Calculator, specifically referred to as 2026 ACC v1a.

⁹ California Standard Practice Manual Economic Analysis of Demand Side Programs and Projects, October 2001, p.19

¹⁰ U.S. EPA, *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, November 2023. https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf

THEREFORE IT IS ORDERED THAT:

1. The updates to the Avoided Cost Calculator, as specified herein and further enumerated in documents made available through Appendix A of this Resolution, are adopted for use in demand-side distributed energy resource cost-effectiveness analyses.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed, and adopted at a conference of the Public Utilities Commission of the State of California held on October 8, 2026, the following Commissioners voting favorably thereon:

Commissioner Signature blocks to be added
upon adoption of the resolution

Dated _____, at <Voting meeting location>, California

Appendix A

Avoided Cost Calculator 2026 Update documents are available online.

The 2026 ACC Gas Model, the 2026 ACC Electric Model, the 2026 ACC Integrated Calculation Inputs, the 2026 ACC Documentation, and related data files are all available for download on the CPUC website: [DER Cost-Effectiveness \(ca.gov\)](#)

Alternatively, the ACC Documentation and files will also be shared on the R.22-11-013 Service List and can be found here: [2026 ACC | Powered by Box](#).