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Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 22-11-013:

This is the proposed decision of Administrative Law Judge Jack Chang. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's September 3, 2026, Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC: asf
Attachment

Decision **PROPOSED DECISION OF ALJ CHANG (Mailed 7/ 31/2026)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards.	Rulemaking 22-11-013

DECISION ADOPTING UPDATES TO THE AVOIDED COST CALCULATOR

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DECISION ADOPTING UPDATES TO THE AVOIDED COST CALCULATOR

Summary

This decision updates the Avoided Cost Calculator (ACC), beginning with the 2026 ACC. The updates are designed to create a more robust, transparent ACC model that better reflects changing system and load patterns due to increased building and vehicle electrification and growing renewable penetration on the grid.

This decision adopts the following changes to the ACC:

1. Adopts a single electricity-based value to represent both electricity and natural gas greenhouse gas (GHG) values in the ACC and removes the GHG rebalancing component.
2. Adopts a simplified implementation of the Integrated Calculation for Generation Capacity and GHG Costs to address transparency issues and sensitivity to minor inconsistencies between the RESOLVE model and the Strategic Energy & Risk Valuation Model (SERVM).
3. Adopts loss of load hours (LOLH) rather than expected unserved energy (EUE) for calculating ACC capacity allocation factors to measure the frequency of loss of load events.
4. Uses energy prices rather than temperature to allocate generation capacity value to specific days of the year.
5. Represents reliability risk differences of weekdays versus weekends in the ACC's capacity value allocation.
6. Updates the peak capacity allocation factors (PCAF) calculations for transmission avoided costs to use the Integrated Energy Policy Report (IEPR) load forecast for future years, as used in SERVM modelling for calculating energy avoided costs, instead of historical loads.
7. Uses the Discounted Total Investment Method approach to calculate marginal transmission costs for all electric utilities.

This proceeding remains open.

1. Background

1.1. Avoided Cost Calculator

The Commission uses the Avoided Cost Calculator (ACC) to provide guidance across a variety of proceedings on the value of distributed energy resources (DERs) as part of the overall portfolio mix with supply-side resources.[1] The ACC calculates the avoided costs related to the provision of electric and natural gas service. These avoided costs can be categorized into the following types of avoided costs: generation capacity, energy, transmission and distribution capacity, ancillary services, greenhouse gas (GHG) emissions, and high global warming potential gases. The outputs of the ACC are used in the DER cost-effectiveness analysis, including for demand response and energy efficiency, among other purposes.

In Decision (D.) 16-06-007, *Decision to Update Portions of the Commission's Current Cost-Effectiveness Framework*, the Commission directed that a single avoided cost model should apply to all DER proceedings.[2] In D.19-05-019, the Commission approved a formal biennial process, to be conducted in Rulemaking (R.) 14-10-003 or a successor proceeding, to ensure that major changes to the ACC are addressed on a regular basis. D.25-11-005 modified the 2026 update schedule to release the ACC update staff proposal in late March 2026 to align with the adoption of the Integrated Resource Plan (IRP) proceedings' Preferred System Plan (PSP), among other procedural and schedule updates.[3] The updated schedule allows for evidentiary hearing in May of each even-numbered year starting in 2026 if needed and briefing in May and June of each even-numbered

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[1] D.22-05-002 at Finding of Fact 1.

[2] D.16-06-007 at 1, 5-6, Finding of Fact 4, Conclusion of Law 2, and Ordering Paragraph 1.

[3] D.25-11-005 at 9.

year if needed. The modified 2026 update schedule concludes with an adopted decision in late-July of each even-numbered year.

1.2. Relationship between the Avoided Cost Calculator and the Integrated Resource Planning Proceeding

The Commission-led IRP process (designed in R.16-02-007 and continued in R.20-05-003 and R.25-06-019) uses load serving entities' (LSE) generation procurement plans to develop portfolios of electricity resources that ensure procurement meets the state's safety, reliability, and GHG reduction goals in as cost-effective a manner as possible. The portfolios inform procurement of generation resources, and based on the adopted portfolios, the Commission transmits generation portfolios to the California Independent System Operator (CAISO) to inform its Transmission Planning Process (TPP). Additionally, the Commission has ordered jurisdictional LSEs to procure resources to meet reliability needs and manage compliance with those procurement orders.

The IRP PSP portfolio has been used as the basis for the ACC's calculations, providing the baseline assumptions against which marginal costs can be evaluated. The data the IRP uses includes existing, contracted, and planned resources that the LSEs submit to the Commission in their individual IRP Plans, plus any additional resources the Commission, through this process, finds necessary for system reliability and GHG emissions goals. In some years, the PSP that the Commission adopts is also transmitted to the CAISO for its TPP. In years when there is no new PSP portfolio, the Commission has various options for TPP Base Case portfolio adoption, usually including updates to the prior year's TPP Base Case with key input updates made by staff or adjustments made based on the latest IEPR electricity demand forecast. The Commission transmits at least one TPP portfolio (a "Base Case") to the CAISO for use in its TPP.

Typically, in years when the PSP is adopted by the Commission, the Commission's Energy Division uses the PSP portfolio to inform the ACC update staff proposal.

D.25-11-005 determined that the IRP PSP would not be ready by early 2026 due to the recently updated three-year cycle for the PSP, therefore an alternative was needed.[4] D.25-11-005 found that using the IRP's approved TPP Base Case portfolio transmitted to the CAISO was also reasonable based on the IRP's current anticipated cycle timeline and the ACC's timing needs.[5] The decision found that:

> [b]oth the PSP and the IRP TPP portfolio are Commission-adopted products that leverage the same stakeholder-vetted inputs, assumptions and modeling. As such, we find that both can sufficiently serve the purpose of providing the ACC with the baseline assumptions against which marginal costs can be evaluated.[6]

The decision concluded: "Moving forward, on an ongoing basis, the ACC Update cycle will use the IRP portfolio that best aligns with the timing needs of the ACC Update cycle, meaning the portfolio that was most recently adopted by the Commission."[7]

2. 2024 Avoided Cost Calculator Decision

In R.22-11-013, the Commission issued D.24-08-007 (2024 ACC Decision) to adopt changes to the ACC during the 2024 ACC Update Cycle. Among other things, the 2024 ACC Decision ordered that the ACC should use the IRP's latest

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[4] D.25-11-005 at 13.

[5] D.25-11-005 at 13.

[6] D.25-11-005 at 13.

[7] D.25-11-005 at 13-14.

adopted system plan as the baseline portfolio.[8] The 2024 ACC Decision also concluded that the Integrated Calculation for Generation Capacity and GHG Costs (Integrated Calculation) should be adopted for the ACC.[9] The calculation jointly derives values for both generation capacity and GHG costs for the ACC. The decision found it was reasonable to include only utility solar and lithium-ion energy storage resources in the Integrated Calculation, and also found it was reasonable to exclude resources that are procured to satisfy the Mid-Term Reliability Procurement Orders adopted in R.20-05-003 from the Integrated Calculation model.

Regarding calculating avoided generation capacity costs, the decision found that a minimum level for the ACC model should be set at the fixed operations and maintenance costs (O&M) of existing gas generation and a minimum level of avoided GHG costs for the ACC model should be set at the cap-and-invest price forecasts. The decision also defined alternative storage dispatch logic to be used in the Strategic Energy & Risk Valuation Model (SERVM) to calculate the hourly generation capacity allocation prior to input in the ACC model and reasonable benchmarking and calibration for the SERVM model.

3. Staff Proposal

The Commission's Energy Division produced a staff proposal in which staff proposed nine major updates for the 2026 ACC (Staff Proposal). The Staff

[8] D.24-08-007 Conclusion of Law 1.

[9] D.24-08-007 Conclusion of Law 2.

Proposal was issued for party comments in an assigned ALJ ruling on April 23, 2026. A Revised Staff Proposal was issued on June 5, 2026.[10]

The proposed updates in the Revised Staff Proposal are:

1. Add a Single Value to GHG Emission Reductions: Staff recommends applying a single electricity-based value to represent both electricity and natural gas GHG values in the ACC.[11]
2. Remove the GHG Rebalancing Component: Staff advises that a GHG rebalancing component is no longer necessary with the adoption of a single GHG emissions reductions value.
3. Cap Total GHG Value at the Societal Cost of Carbon (SCC): Staff recommends implementing a cap on the GHG value in both electric and gas models equal to the high societal cost of carbon adopted in the Societal Cost Test.
4. Refine the Integrated Calculation of Generation Capacity and GHG Avoided Costs (Integrated Calculation): Staff proposes a simplified implementation of the Integrated Calculation to address transparency and sensitivity to minor inconsistencies between RESOLVE and SERVM models.
5. Use Loss of Load Hours (LOLH) Rather than Expected Unserved Energy (EUE) for Allocation Factors: Staff proposes using LOLH as the basis for the ACC capacity allocation factors to measure the frequency of loss of load events.
6. Use Energy Prices Rather than Temperature for High Generation Capacity Value: Staff recommends using

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[10] The Revised Staff Proposal modified the Integrated Calculation proposed for the 2026 ACC to address output issues with the previously proposed Integrated Calculation. The revised Staff Proposal also modified the transmission avoided cost calculation for Southern California Edison to only include a Discounted Total Investment Method (DTIM) approach rather than a combined DTIM and Locational Net Benefits Analysis calculation.

[11] Staff refers to the Commission's Energy Division working with the consultant Energy and Environmental Economics (E3).

energy prices rather than temperature to calculate the high generation capacity value to reflect increased electricity use in both summer and winter months.

7. Represent Reliability Risk Difference of Weekdays Versus Weekends in Capacity Value Allocation: Staff recommends allocating days with non-zero reliability risk to weekends and weekdays to align with the final capacity value allocation.
8. Refine Hourly Allocation of Transmission Capacity Value: Staff recommends updating the peak capacity allocation factors (PCAF) calculations to use Integrated Energy Policy Report (IEPR) load forecasts for future years instead of historical loads.
9. Align Transmission Avoided Cost Calculations Across Utilities: Staff recommends using only the Discounted Total Investment Method (DTIM) to calculate marginal transmission costs for all electric utilities.

4. Proceeding History

On November 23, 2022, the Commission issued Order Instituting Rulemaking 22-11-013 to achieve consistency of cost effectiveness assessments, improve data access and use, and consider equipment performance standards for DER customer programs.[12] R.22-11-013, the successor to R.14-10-003, provides the procedural framework for advancing the vision articulated in the Customer

[12] DER customer programs are programs offered to ratepayers by utilities, or other load-serving entities, that enable participants to manage their energy use by purchasing energy efficient or electric generation technologies, making behavioral changes, or engaging in other activities that occur on the customer's premises (often called "behind-the-meter"). They are sometimes referred to as "demand-side management" programs because they allow customers to manage their own demand for electricity or natural gas. They are also referred to as "distributed energy resource" programs since the technologies used may be small, modular devices that can be distributed throughout the electric grid or natural gas system, rather than centrally-stationed like most utility-scale generation (e.g., power plants). This proceeding will use the terms DER or customer programs to refer only to behind-the-meter activities. The term "distributed energy resources" as used elsewhere sometimes includes small, distributed generation or energy storage resources owned or procured by load serving entities, which are not considered here.

Programs Track of the Commission's DER Action Plan 2.0. The goal of the DER Action Plan, which R.22-11-013 helps achieve, is to enable all customers to effectively manage their energy usage in a manner that facilitates equitable participation in DER resources and equitable distribution of DER benefits. The DER Action Plan also aims to align activities across evolving rate design and load flexibility, distribution planning, and IRP objectives.

On May 31, 2023, the assigned commissioner issued a Scoping Memo and Ruling that bifurcated this proceeding into two phases. Phase One focuses on issues related to the cost effectiveness of customer DER programs, including updating the ACC, and policies on improving data usage and access to help customers make informed decisions about adoption, evaluation, and utilization of DERs. Phase Two focuses on developing equipment performance standards. The Scoping Memo and Ruling described two tracks for Phase One. Track One examines how to make cost effectiveness assessments more accurate and consistent across DER programs. Track Two examines the rules and requirements to improve data access to facilitate adoption, evaluation, and utilization of DERs by customers and other entities and to improve DER integration with the grid.

As described earlier, D.24-08-007 adopted the 2024 ACC Update, while D.25-11-005 adopted a modified timeline and budget for the biennial ACC updates.

An Amended Assigned Commissioner's Scoping Ruling was issued on March 3, 2026 adding a Track Three to Phase One of R.22-11-013 to examine ACC guiding principles.

An ALJ Ruling was issued on April 23, 2026 requesting party comment on the 2026 ACC Staff Proposal (Staff Proposal). On May 13, 2026, opening comments on the Staff Proposal were filed by the Association of Bay Area Governments for the San Francisco Bay Area Regional Energy Networks (BayREN) and the County of Ventura for the Tri-County Regional Energy Network (3C-REN) filing jointly, Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), California Large Energy Consumers Association (CLECA), San Diego Gas & Electric Company (SDG&E), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), the Solar Energy Industries Association (SEIA), the Coalition of California Utility Employees (CUE), Small Business Utility Advocates (SBUA), and the Natural Resources Defense Council (NRDC). On May 18, 2026, reply comments on the Staff Proposal were filed by BayREN and 3-C Ren filing jointly, PG&E, SCE, CUE, SEIA, SDG&E, SoCalGas, and CLECA.

On June 5, 2026, an ALJ Ruling was issued seeking party comment on a revised 2026 ACC Staff Proposal (Revised Staff Proposal). On June 18, 2026, opening comments on the Revised Staff Proposal were filed by Clean Coalition, SBUA, PG&E, NRDC, and Cal Advocates. On June 19, 2026, opening comments on the Revised Staff Proposal were filed by BayREN and 3-C Ren filing jointly, SoCalGas, SEIA, CLECA, SDG&E, SCE, and the Southern California Regional Energy Network (SoCalREN). On June 26, 2026, reply comments on the Revised Staff Proposal were filed by SEIA, CLECA, PG&E, and SCE.

5. Submission Date

This matter was submitted on June 26, 2026 upon submission of reply comments on the Revised Staff Proposal.

6. Issues Before the Commission

The issue considered in this decision is:

a. What ACC updates should the Commission adopt, beginning with the 2026 ACC?

This decision adopts ACC updates, beginning with the 2026 ACC. The Commission will continue to consider DER data access and privacy issues in Track Two of this proceeding and ACC guiding principles in Track Three of this proceeding.

The following sections describe each proposed change to the ACC in the Staff Proposal and Revised Staff Proposal, party comments and proposals on the proposed change, and a discussion of the Commission's determination regarding the proposed change.

7. Implementing a Single Electricity-Based Value to GHG Emission Reductions

The Staff Proposal recommends using a single electricity-based value to calculate GHG emission reductions rather than using one value to calculate electricity-based GHG emission reductions and another value to calculate natural gas-based GHG emission reductions.

Currently, the state of California lacks a cross-sector basis for valuing GHG reductions since state climate policy is implemented through sector-specific planning frameworks.[13] Additionally, the state has not yet developed sector-specific modeling of marginal abatement costs for the natural gas sector beyond the current interim value based on a 2021 California Energy Commission (CEC) report on the GHG abatement cost in buildings.[14]

The Staff Proposal proposes applying the more current electric-sector GHG value to all GHG reductions in the ACC model, including in both electric and gas

[13] Staff Proposal at 5.

[14] Staff Proposal at 5.

models.[15] The GHG value calculated in the electric model is composed of the cap-and-invest value, which represents the IEPR price forecast for the cap-and-invest 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. This value aligns with the marginal GHG value indicated by the IRP, which is considered the state's most robust and transparent modeling process that analyzes the cost to meet specified GHG reduction goals.[16] Adopting the electric-sector GHG value would thus provide a coherent basis for evaluating emissions reductions across the electric and gas sectors. The Staff Proposal states that the electric-sector GHG value also provides a consistent price signal for DER investment by treating all GHG reductions equally.[17] The Staff Proposal states that 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.[18]

In their comments on the Staff Proposal, PG&E and SoCalGas support the staff's recommendation to use a single electricity-based GHG value across both the electric and gas ACC models. PG&E cites "the absence of a natural gas-specific modeling and planning framework akin to the (IRP) used in the electric sector" while SoCalGas cites "the absence of a natural gas specific adder" while agreeing that using the more recently updated electricity-based value would be a more robust measure of the GHG avoided cost value.[19] SoCalGas suggests that the Commission categorize the electric value in the gas ACC as an "updated

[15] Staff Proposal at 5.

[16] Staff Proposal at 5.

[17] Staff Proposal at 5.

[18] Staff Proposal at 6.

[19] PG&E Opening Comments at 2, SoCalGas Opening Comments at 1-2.

interim solution until a specific natural gas adder is established through the Customer DER proceeding or other proceeding."[20]

SCE, Cal Advocates, CUE, and NRDC oppose using a single electricity-based GHG value across both the electric and natural gas ACC models.[21] SCE states that developing a natural gas sector GHG avoided cost value that more accurately reflects the cost of decarbonizing the gas system would make cross-sectoral comparisons of GHG costs more robust.[22] SCE also states that the GHG figure is supposed to measure avoided costs, not the value of each resource as described in the Staff Proposal, and "the GHG avoided cost assumed in the ACC has generally been less than the likely benefit."[23] SCE states that "gas and electric sector abatement costs are substantially different" and that "[a] single multi-sector value risks sending an erroneous signal that gas-sector emissions can be reduced at the same marginal cost as electricity-sector emissions."[24] Cal Advocates makes a similar argument about the different GHG abatement costs in the electric and gas sectors and argues that "[u]sing the electric GHG value for the natural gas sector would systemically undervalue electrification measures because there is no comparable technology to solar and battery storage to decarbonize direct natural gas consumption in buildings."[25] CUE echoes SCE and Cal Advocates' argument about the different GHG abatement costs of gas and electric resources and suggests the Commission develop "an economy-wide

[20] SoCalGas Opening Comments at 2.

[21] SCE Opening Comments at 5-7, PAO Opening Comments at 4-7, CUE at 3-6, NRDC Opening Comments at 2-3.

[22] SCE Opening Comments at 5.

[23] SCE Opening Comments at 6.

[24] SCE Opening Comments at 6-7.

[25] Cal Advocates Opening Comments at 5.

or cross-sector analytical framework, not by importing an electric-sector IRP value into the gas model."[26] NRDC states that Energy Division staff "have selected the lower of the two possible abatement values as the uniform GHG Adder" rather than the marginal cost of reducing emissions across both sectors, which "would be set by whichever sector faces the higher marginal abatement cost."[27] NRDC states: "This choice will leave cost-effective carbon abatement opportunities in the gas sector unrealized."[28]

BayREN and 3C-REN state that using a single electricity-based GHG value across both the electric and gas ACC models could "directly reduce the cost-effectiveness of fuel-switching energy efficiency measures" but state that a final decision on the issue can't be made without first issuing a decision on Track 3 guiding principles.[29] BayREN and 3C-REN state that that the Commission should make any policy determination to phase out natural gas energy efficiency measures through the Viable Electric Alternatives framework that the Commission is developing in its energy efficiency rulemaking.[30]

CLECA, SBUA, SDG&E, and SEIA take no stand on the issue.[31]

The Commission acknowledges the shortcomings of using an electricity-based GHG emissions reductions value to represent both electric and natural gas-based resources. However, the Commission finds that the electric-sector value is the most appropriate value available at this time for the interim

[26] CUE Opening Comments at 5.

[27] NRDC Opening Comments at 3.

[28] NRDC Opening Comments at 3.

[29] BayREN and 3C-REN Opening Comments at 2-3.

[30] BayREN and 3C-REN Reply Comments at 4-5.

[31] CLECA Opening Comments at 7.

valuation of DERs' GHG emissions reduction potential. As several parties note, using the electricity-based GHG emissions value risks undervaluing electrification measures and equating electricity-based GHG reduction measures with gas-based measures. However, using that value across sectors as an interim measure in the 2026 ACC cycle outweighs those drawbacks by employing a GHG emissions reduction value that aligns with the marginal GHG value used in the IRP and is also more frequently updated than the current interim value of natural gas-based GHG emission reductions. Using that electric-sector value on an interim basis rather than sticking with a natural gas-based indicator that potentially overstates the value of electrification measures benefits ratepayers by keeping the cost of those programs from becoming inflated – an important consideration as California wrestles with rising utility costs.

In future ACC cycles, the Commission should re-evaluate whether to continue to use the electric sector GHG value on an interim or permanent basis, or whether some other value more accurately differentiates between gas sector and electric sector GHG abatement costs in the ACC. In the meantime, it is in the ratepayers' interest to adopt an electricity-specific GHG emissions reduction value across the electricity and gas sectors in the ACC that more accurately reflects abatement costs. Accordingly, this decision updates the ACC to apply a single electricity-based value to represent both electricity and natural gas GHG values in the ACC.

8. Removing the GHG Rebalancing Component

The Staff Proposal recommends removing the GHG rebalancing component of the ACC. The GHG rebalancing component of the ACC was originally introduced into the ACC to account for the cross-sector implications of electrification as the electric and gas ACC models used separate GHG values.[32] Specifically, the rebalancing component is intended to capture how changes in electric sector load may lead to changes in the absolute GHG planning target for the electric sector. For example, increases in load due to electrification that reduce emissions in other sectors of the economy may be accompanied by an increase in allowable emissions within the electric sector. The Staff Proposal states that the rationale for the GHG rebalancing component becomes irrelevant if the ACC adopts a single electric-sector GHG value to represent all GHG valuations in the ACC regardless of whether they occur in the electric or natural gas sectors.[33] As a result, applying the electric-sector GHG values uniformly allows the ACC to represent marginal cost signals capturing the full GHG impacts of electrification and fuel-substitution measures without an additional adjustment step.[34]

Removing the GHG rebalancing component also increases consistency with the IRP by aligning with the most current GHG reductions target and the most recent IRP modeling, which are both updated to reflect any electric sector target changes in subsequent ACC cycles.[35] The proposal also would align the GHG value in the ACC with the marginal GHG value calculated in the IRP, which would help ensure the Commission uses consistent GHG values across proceedings.

SEIA and PG&E support removing the GHG rebalancing component. SEIA states that "so long as the ACC reflects the marginal resource costs from the

[32] Staff Proposal at 6.

[33] Staff Proposal at 6.

[34] Staff Proposal at 6.

[35] Staff Proposal at 6.

current IRP portfolio, it will include the ongoing costs needed to re-balance the electric sector to meet its full GHG emission reduction responsibilities."[36]

SCE, Cal Advocates, CUE, BayREN, and 3C-REN oppose removing the GHG rebalancing component. SCE states that the rebalancing component "exists to approximate a quantity adjustment – i.e. a proportional reallocation of allowable GHG emissions – when load shifts among sectors due to electrification and other load-modifying DERs."[37] SCE then quotes from the Staff Proposal that GHG emissions from the electric sector would be expected to increase proportionally if electrification load was added to an electric sector IRP portfolio.[38] Cal Advocates states that the Commission should not adopt the electric GHG value for all sectors and thus should retain the GHG rebalancing component.[39] CUE states that the Commission should first analyze the GHG emission impacts of load-reducing electric DERs, gas-to-electric building electrification measures, and transportation electrification measures and determine whether a single electricity-based GHG value eliminates the need for rebalancing across those three sectors.[40] BayREN and 3C-REN state that removing the GHG rebalancing component would create a "double penalty" for local electrification programs by making the electricity consumed by heat pumps and electric vehicles more carbon-heavy and expensive on paper.[41]

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[36] SEIA Opening Comments at 3.

[37] SCE Opening Comments at 8.

[38] SCE Opening Comments at 8.

[39] Cal Advocates Opening Comments at 7.

[40] CUE Opening Comments at 9.

[41] BayREN and 3C-REN Comments at 8.

SEIA responds that the IRP process already includes the expected growth in demand due to fuel switching technologies such as EVs and heat pumps.[42] CUE challenges this statement by stating that the ACC evaluates program-attributable and tariff-attributable DER impacts while the IRP forecast includes expected baseline electrification, not incremental DERs and programs.[43]

NRDC, SoCalGas, SDG&E, SBUA, and CLECA take no position on the GHG rebalancing component.

The Commission agrees with SCE that the GHG Rebalancing component "exists to approximate a quantity adjustment—i.e., a proportional reallocation of allowable GHG emissions—when load shifts among sectors due to electrification and other load-modifying DERs."[44] The Commission also agrees with the Staff Proposal that this cross-sector reallocation of allowable GHG emissions is appropriately accounted for by aligning the ACC with IRP modelling and that "[i]f 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."[45] This appropriately aligns IRP and ACC modelling, instead of only assuming a change to the allowable GHG emissions in the ACC, which is what the GHG rebalancing component currently does. Accordingly, this decision updates the ACC to remove the GHG rebalancing component.

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[42] SEIA Reply Comments at 3.

[43] CUE Reply Comments at 11-12.

[44] SCE Opening Comments at 8.

[45] Staff Proposal at 6.

9. Capping Total GHG Value at the Societal Cost of Carbon

The Staff Proposal recommends implementing a cap on the GHG value in both the electric and gas models equal to the high value of the SCC in the Societal Cost Test.[46]

The proposal states that such a cap on the final GHG value following the Integrated Calculation would represent a safeguard for ratepayers against a GHG value that exceeds the value that emissions reductions provide to society.[47] The proposal states that capping GHG values within the ACC would reduce the volatility of the ACC GHG value between ACC cycles and thus ensure that a short-term high GHG value is not being used to determine long-term DER investments in the time between IRP and ACC cycles.[48]

SEIA, SCE, and CUE support implementing a cap on the GHG value in both the electric and gas models equal to the high SCC adopted in the Societal Cost Test. SEIA also states, however, that the SCC cap is useful only if it is regularly updated and notes that the Staff Proposal does not define what an up-to-date, scientifically determined SCC value would be for a GHG value cap.[49] SCE notes that an avoided ACC GHG cost cap will minimize the impact of the timing lag resulting from the 2026 ACC assuming GHG targets remain at levels established in D.24-02-047 before the 2024-2026 IRP cycle can consider whether changed conditions warrant an update to the electric sector GHG targets and/or

[46] Staff Proposal at 6.

[47] Staff Proposal at 6.

[48] Staff Proposal at 6.

[49] SEIA Opening Comments at 3-4.

trajectory.[50] CUE points to Staff Proposal language that states that "future electric-sector GHG targets should be adjusted if electric abatement costs are too high for ratepayers to bear or if reductions in other sectors can be achieved more cost-effectively."[51] CUE also states that the Commission should reject implementation proposals that automatically replace capped GHG values with increased generation capacity values.[52] CUE states that Energy Division staff should disclose the annual cap values, the years in which the cap binds, and how the cap interacts with the Integrated Calculation.[53]

Cal Advocates, SDG&E, SoCalGas, NRDC, BayREN, and 3C-REN oppose implementing a cap on the GHG value in both the electric and gas models. Cal Advocates states that the Staff Proposal lacks enough information to determine whether using SCC as an upper limit on the GHG value is merited.[54] SDG&E states that tying the cap to the federal SCC is improper, pointing to the volatility of the federal SCC and what it says is the mismatch between the national scale of the federal SCC and the California-specific marginal abatement cost.[55] SDG&E also states that the SCC measures the present value of societal damage from incremental GHG emissions, not the marginal cost of abating those emissions.[56] SDG&E proposes using the maximum marginal GHG shadow price adopted in

[50] SCE Opening Comments at 3.

[51] CUE Opening Comments at 3.

[52] CUE Reply Comments at 1-2.

[53] CUE Reply Comments at 7.

[54] PAO Opening Comments at 7.

[55] SDG&E Opening Comments at 2-3.

[56] SDG&E Reply Comments at 2.

the most recent IRP cycle as a cap.[57] SCE challenges that proposal, stating the GHG shadow price is only a different way of calculating abatement costs associated with meeting the state's 2045 GHG emissions goal rather than an actual cap on costs based on what is reasonable for customers to bear.[58] CUE also opposes SDG&E's suggestion, stating that the GHG shadow price is a modeled compliance or abatement cost, not an estimate of the societal value of the emissions reductions.[59] SoCalGas states that capping California's GHG avoided costs at the SCC will create inconsistencies across the ACC, IRP, cap-and-invest, and other regulatory frameworks and that such a cap should be implemented across proceedings if it is implemented.[60] SoCalGas also states that capping the GHG avoided cost at the SCC should be part of broader policy change and not as a modeling input to the ACC.[61] NRDC states that capping the value of GHGs on the demand side but not applying it to the supply side will cause demand side resources to be artificially undervalued relative to supply side values.[62] BayREN and 3C-REN state that implementing a GHG value cap based on the SCC would undervalue true societal impacts and "not reflect the full impacts of decisions made as a result of ACC application" and would result in the same amount of avoided carbon emissions being assigned a higher value when they're the result of utility-built infrastructure compared to when they're the product of energy

[57] SDG&E Reply Comments at 2.

[58] SCE Reply Comments at 2.

[59] CUE Reply Comments at 7.

[60] SoCalGas Opening Comments at 2-3.

[61] SoCalGas Reply Comments at 4.

[62] NRDC Opening Comments at 4.

efficiency measures.[63] BayREN and 3C-REN also state that if the Commission adopts a GHG value constraint, it must be applied equally to the supply-side IRP proceedings that use the same GHG shadow prices.[64] Finally, BayREN and 3C-REN state that Energy Division should treat Societal Cost Test values as a floor for GHG cost accounting in standard cost-effectiveness tests.[65] SoCalGas challenges BayREN and 3C-REN's proposal, stating that the SCT was intended to be an information-only cost effectiveness test and not to be used for Total Resource Cost TRC calculations.[66]

CLECA states that "[c]apping GHG is a reasonable measure" but questions using the high Societal Cost Test scenario as the cap level "without explanation" and states that the cap should be implemented consistently with the Integrated Calculation framework, and not only in the final output stage.[67] SEIA and PG&E also support applying the cap in the Integrated Calculation before the GHG value is used as an input.[68] SCE challenges CLECA's proposal, stating that applying the cap within the Integrated Calculation model would increase avoided generation capacity costs in years where the model calculates an avoided GHG cost that exceeds the SCC.[69] CLECA proposes setting the cap at the Base SCC level.[70]

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[63] BayREN and 3C-REN Opening Comments at 7-8.

[64] BayREN and 3C-REN Reply Comments at 2.

[65] BayREN and 3C-REN Opening Comments at 11.

[66] SoCalGas Reply Comments at 2.

[67] CLECA Opening Comments at 7-8, CLECA Reply Comments at 6.

[68] SEIA Opening Comments on June 5 Ruling at 4-5, PG&E Reply Comments on June 5 Ruling at 2.

[69] SCE Reply Comments at 4, SCE Reply Comments on June 5 Ruling at 3.

[70] CLECA Reply Comments at 6.

PG&E supports capping the total GHG value on an interim basis but urges the Commission to work with the California Air Resources Board (CARB) on a marginal measure in the next CARB Scoping Plan due in 2027 that informs both the demand and supply sides.[71] SCE challenges PG&E's proposal, stating that the CARB marginal abatement cost would only be a separate methodology for estimating the costs necessary to reach the state's 2045 GHG emissions goals under status quo conditions and not based on what is reasonable for customers to bear.[72]

SBUA takes no stand on the issue.

The Commission agrees with SoCalGas that capping California's GHG avoided costs at the SCC will create inconsistencies across the ACC, IRP, cap-and-invest, and other regulatory frameworks. The Commission also agrees with NRDC, BayREN, and 3-C Ren that capping the GHG value on the demand side but not applying it to the supply side will cause demand side resources to be artificially undervalued relative to supply side values. Finally, the Commission agrees with SDG&E that the federal SCC may prove to be too volatile and incompatible to use in the ACC.

As explained below, the Integrated Calculation will be updated in the ACC to adopt the RESOLVE model's GHG constraint as used in the IRP to calculate GHG avoided costs from the Commission's IRP proceeding, which will better align ACC and IRP values. Using that "shadow price" will more accurately reflect current valuations of GHG avoided costs than adopting a federal SCC-based cap. Accordingly, this decision does not update the ACC to

[71] PG&E Opening Comments at 2, PG&E Reply Comments at 3.

[72] SCE Reply Comments at 2.

adopt a SCC-based cap on GHG values. The Commission 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.

10. Refining the Integrated Calculation of Generation Capacity and GHG Avoided Costs

The Revised Staff Proposal recommends adopting a simplified implementation of the Integrated Calculation to address concerns about the calculation's transparency and sensitivities to minor inconsistencies between the results produced by RESOLVE and SERVM.[73]

The 2024 ACC introduced the Integrated Calculation of both GHGs and Generation Capacity Avoided Costs that derived the two cost components simultaneously.[74] Staff implemented the Integrated Calculation as an optimization problem requiring that the net present value of the energy, capacity, and GHG benefits could offset the total cost of the resource.[75] The model also sought to minimize total system costs while producing internally consistent annual generation capacity avoided costs and GHG avoided costs.[76] The staff implemented the model through a Python-based script and workbook that summarized key assumptions and data sources.[77] Finally, the 2024 ACC adopted staff recommendations to only include in the Integrated Calculation model utility solar and lithium-ion energy storage resources because they were the dominant resource additions from the IRP.[78]

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[73] Revised Staff Proposal at 7.

[74] Revised Staff Proposal at 7.

[75] Revised Staff Proposal at 7.

[76] Revised Staff Proposal at 7.

[77] Revised Staff Proposal at 7.

[78] D.24-08-007 at 20.

For the 2026 ACC Update, staff initially proposed a simplified formula that retained the same principles of the 2024 ACC Integrated Calculation but used two governing equations to directly calculate a resource's GHG avoided cost and annual generation capacity costs for each year.[79] After SEIA and CLECA pointed out that the proposed Integrated Calculation produced inconsistent results,[80] a June 5, 2026 ALJ Ruling (June 5 Ruling) proposed a revised Integrated Calculation that uses only one governing equation to calculate a resource's generation capacity costs for each year.[81]

The revised 2026 ACC model update first adopts the "shadow price" of the RESOLVE model's GHG constraint as used in the IRP to calculate GHG avoided costs. The "shadow price" represents the marginal cost per metric ton incurred by California ratepayers to achieve that level of carbon reductions.[82] The Revised Staff Proposal proposed calculating generation capacity value in the ACC using a single equation to represent a hybrid resource composed of marginal resources selected based on the resources built into the IRP portfolio.[83] The hybrid resource used in the revised 2026 ACC model would be solar + 4-hour storage until 2036 and then solar + 8-hour storage thereafter "[c]onsidering the portfolio of resources from the IRP used in the 2024 ACC."[84] The combination of resources

[79] Revised Staff Proposal at 7.

[80] SEIA Opening Comments at 5, CLECA Opening Comments at 10-12.

[81] Revised Staff Proposal at 9-10.

[82] Revised Staff Proposal at 8.

[83] Revised Staff Proposal at 9.

[84] Revised Staff Proposal at 9.

included in the hybrid resource may change and will be based on the latest IRP or TPP modeling.[85]

For the hybrid marginal resource in year n, the relationship between resource costs and avoided costs is expressed as:

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

RECC is the gross real economic carrying charge, R_{energy} is net energy revenues, AC_{GC} is the generation capacity avoided costs, Q_{ELCC} is the deemed resource adequacy contribution, AC_{GHG} is the GHG avoided costs, and Q_{GHG} is the marginal GHG impacts.

Staff stated that the new calculation will be easier for stakeholders to review and audit since it is entirely contained in an Excel workbook.[86] The modified method is more tolerant of inconsistent inputs because it doesn't rely on optimization.[87] Staff also highlighted that a single resource was often driving both GHG and generation capacity value leading to results that were set based on the bounds of the problem.[88]

Staff proposed to continue to implement lower bounds on both the generation capacity and GHG avoided costs, aligned with the ACC modeling, with the generation capacity bounds reflecting the assumed ongoing fixed O&M cost of existing gas resources, while the floor for the GHG avoided costs is set equal to the forecast for cap-and-invest allowance prices used in the IRP.[89]

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[85] Revised Staff Proposal at 9.

[86] Revised Staff Proposal at 8.

[87] Revised Staff Proposal at 8.

[88] Revised Staff Proposal at 7.

[89] Revised Staff Proposal at 10.

SDG&E supports the revised Integrated Calculation but suggests that Energy Division publish a side-by-side comparison of the calculation's outputs under the new and prior methodologies for at least one common set of inputs or one common year.[90]

SCE supports the revised Integrated Calculation but proposes aligning the generation capacity value in the ACC with the generation capacity value in the IRP.[91] PG&E supports SCE's proposal but warns that the capacity values in the ACC and IRP models should be checked for consistency first.[92] SEIA opposes SCE's proposal, stating that the generation capacity costs estimated in the early years of the modeled IRP portfolio are distorted due to resources chosen not based on economic reasons but because they were included in the LSEs' resource plans.[93] SEIA also states that the IRP and Integrated Calculation have different purposes, as the IRP is intended to optimize the selection of a portfolio of resources based on preferences in the LSEs' resource plans while the Integrated Calculation aims to determine an avoided generation capacity cost that enables a marginal resource from the IRP to recover its costs fully.[94] CLECA also opposes SCE's suggestion about the ACC adopting the IRP's generation capacity value.[95]

SCE also suggests reintroducing the smoothing step for GHG and generation capacity avoided costs included in the original Staff Proposal using a

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[90] SDG&E Opening Comments on June 5 Ruling at 1-2.

[91] SCE Opening Comments on June 5 Ruling at 2-3.

[92] PG&E Reply Comments on June 5 Ruling at 1-2.

[93] SEIA Reply Comments on June 5 Ruling at 2-3.

[94] SEIA Reply Comments on June 5 Ruling at 3.

[95] CLECA Reply Comments on June 5 Ruling at 7-8.

seven-year rolling average to reduce inter-year volatility.[96] CLECA and SEIA agree with SCE's suggestion about the smoothing step.[97]

SBUA and PG&E support the revised Integrated Calculation while SoCalGas supports the revised Integrated Calculation as an interim measure.[98]

SEIA overall supports the revised Integrated Calculation but states that it should incorporate a wider range of resources.[99] Additionally, SEIA recommends moving up, to 2029-2031, the switch from the model's 4-hour battery assumption to an 8-hour battery assumption to avoid the major swings in the results during the transition year.[100] CLECA supports SEIA's recommendation on modifying the transition from 4-hour to 8-hour battery assumptions.[101]

CLECA states that the revised Integrated Calculation is not technology-agnostic and excludes resources that the IRP relies upon for reliability.[102] SEIA agrees that the Integrated Calculation should include more resources.[103] CLECA also states that the Revised Staff Proposal does not explain why the revised Integrated Calculation chooses a hybrid solar-plus-storage resource versus another resource and that it remains unstable because it relies on "a poorly chosen, incomplete set of resources with attributes that sit too close together to

[96] SCE Opening Comments on June 5 Ruling at 3.

[97] CLECA Reply Comments on June 5 Ruling at 6-7, SEIA Opening Comments on June 5 Ruling at 8.

[98] SoCalGas Opening Comments on June 5 Ruling at 1, SBUA Opening Comments on June 5 Ruling at 1, PG&E Opening Comments on June 5 Ruling at 1.

[99] SEIA Opening Comments on June 5 Ruling at 9-10.

[100] SEIA Opening Comments on June 5 Ruling at 9-10.

[101] CLECA Reply Comments on June 5 Ruling at 6.

[102] CLECA Opening Comments on June 5 Ruling at 3.

[103] SEIA Reply Comments on June 5 Ruling at 5.

produce meaningful, stable results."[104] SEIA agrees with CLECA's comments, stating "hybrids are not a candidate resource in RESOLVE, and the IRP does not require or plan for solar and storage projects to be developed together as hybrids."[105] CLECA writes that the natural gas O&M cost floor is understated because it omits taxes and insurance costs and that the revised Integrated Calculation subordinates capacity value to the GHG value and removes the independence of modeled resources.[106] SCE and SEIA agree with CLECA's comments about the natural gas O&M cost floor being too low.[107] Finally, CLECA questions the accuracy of the results of the SERVM and RESOLVE models.[108]

BayREN and 3C-REN state that the Commission should publish the Integrated Calculation's GHG outputs and allow for party comment before approving a final calculation.[109] BayREN and 3C-REN also write that the Commission should not approve a final ACC model before deciding on guiding principles in Track 3 of this proceeding.[110]

SoCalREN opposes the revised Integrated Calculation, stating that "collapsing GHG abatement costs into a single value oversimplifies their true variation and undermines the model's ability to serve Equity customers effectively." SoCalREN argues that GHG abatement costs really vary by

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[104] CLECA Opening Comments on June 5 Ruling at 3.

[105] SEIA Reply Comments on June 5 Ruling at 4.

[106] CLECA Opening Comments on June 5 Ruling at 5 and 7-8.

[107] SCE Opening Comments at 11-13, SEIA Reply Comments on June 5 Ruling at 5.

[108] CLECA Opening Comments on June 5 Ruling at 11-13.

[109] BayREN and 3C-REN Opening Comments on June 5 Ruling at 4.

[110] BayREN and 3C-REN Opening Comments on June 5 Ruling at 5.

customer sector, e.g., differing between large industrial and equity-focused multifamily sectors.[111]

NRDC states that the Staff Proposal should not presume that future clean energy procurement targets will be adjusted if emission reductions can be achieved more cost effectively elsewhere due to statutory electric sector specific mandates.[112]

The Commission agrees with SBUA, PG&E, SoCalGas, SDG&E, and SCE that the revised Integrated Calculation fixes the inconsistent results from the previous Integrated Calculation proposal issued with the April 23, 2026 ALJ Ruling. Additionally, the Commission agrees with SCE that the "changes improve transparency, reduce model complexity, and better align the ACC with underlying IRP outcomes."[113] The Commission also agrees with SBUA that the "additional refinement of representing marginal resources as hybrid resources in a single equation should ensure that the Integrated Calculation accurately accounts for inputs that do not indicate a system in equilibrium."[114] The Commission adopts solar generation and battery storage as the hybrid resource in the Integrated Calculation because they are the marginal resources in the IRP model.

The Commission declines to align the generation capacity value in the ACC with the generation capacity value in the IRP, as suggested by SCE. The Commission agrees with SEIA that the IRP and Integrated Calculation have different purposes. Also, the Commission notes that hourly energy prices are

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[111] SoCalREN Opening Comments on June 5 Ruling at 2-3.

[112] NRDC Opening Comments at 4.

[113] SCE Opening Comments on June 5 Ruling at 1.

[114] SBUA Opening Comments on June 5 Ruling at 1.

uniquely calculated in the ACC (and not in the IRP) and considering them in the generation capacity value calculation provides additional information that is not included in the IRP generation capacity shadow prices.

The Commission similarly declines to include a wider range of resources in the Integrated Calculation as suggested by SEIA. The Commission notes that the resources providing marginal GHG value and generation capacity value reflect the largest avoided cost value needed to make a resource whole. The Integrated Calculation uses solar and storage (4-hour in near-term years and 8-hour in later years) as the marginal resources because both resources are selected economically throughout the IRP planning horizon, reflecting their respective long-term roles as scalable resources meeting the state's reliability and decarbonization goals. The 2024 version of the ACC adopted this resource mix, which remains the same in the 2026 ACC.

Responding to CLECA's comments questioning the use of a hybrid solar-plus-storage resource in the Integrated Calculation, the Commission notes that the hybrid resource solution captures the interdependence of solar and storage resources without requiring inputs to show a system perfectly in equilibrium. The adoption of the hybrid solar-plus-storage resource also addresses party concerns that the original methodology understated the GHG reduction benefit associated with solar because it does not capture that solar is used to charge storage, which subsequently discharges during hours with high GHG emissions.

The Commission declines to publish any calculation outputs at this time, as suggested by SDG&E, BayREN, and 3C-REN, as the 2026 ACC is a methodological proposal and it would be premature to share results and values prior to the revised model's approval.[115] The Commission also declines to delay approval of the 2026 ACC model until after deciding on guiding principles in Track 3 of this proceeding.

In response to SCE, CLECA, and SEIA's recommendation that the Commission re-introduce a smoothing step for GHG and generation capacity avoided costs, the Commission acknowledges that generation capacity values can be volatile when there are step changes in resource costs but the Commission declines to adopt a smoothing step in the 2026 ACC so that it can maintain flexibility in implementing smoothing for future updates.

In response to SEIA's recommendation that the revised ACC model move up to 2029-2031 the switch from the model's four-hour battery assumption to an eight-hour battery assumption, the 2026 ACC calculation will move up the hourly switch in 2028 to align with the latest IRP. Similarly, the Commission declines to modify the natural gas O&M cost floor to better align the value with the IRP inputs and assumptions.

Finally, the Commission disagrees with CLECA's comments about the accuracy of the results of the SERVM and RESOLVE models as well as SoCalREN's comments about the impact of the revised model on equity populations. The GHG avoided cost valuation adopted in this decision uses marginal costs generated by IRP supply-side models, that is, the procurement costs attributable to compliance with GHG emissions constraints that can be avoided by DERs. SoCalREN's comment confuses customer costs of abating GHG emissions with the avoided system costs of adding DERs.

[115] See D.22-05-002, Ordering Paragraph 1, as reaffirmed by D.24-08-007 at 5.

Accordingly, this decision adopts the revised Integrated Calculation issued in the June 6 Ruling as a more transparent, simpler method for estimated generation capacity and GHG avoided costs that better aligns with the IRP process.

11. Refining the Hourly Allocation of Generation Capacity Value

The Staff Proposal recommends adopting three refinements to the process for calculating hourly generation capacity avoided costs in the ACC, which aim to quantify, for each hour of the year, the reliability value associated with a marginal megawatt-hour (MWh) of load reduction.[116] The ACC multiplies the annual generation capacity avoided costs by hourly generation capacity allocation factors to produce hourly generation capacity avoided costs.[117]

The 2024 ACC derives 8,760 hourly allocation factors from month-hour averages of expected unserved energy (EUE) outputs from SERVM reliability modelling for the years 2026, 2023, 2035, and 2040. EUE represents the expected quantity of unserved energy when system demand exceeds available generation capacity. EUE values are based on the IRP portfolio, which is then tuned to achieve a system Loss of Load Expectation (LOLE) of 0.1 events per year.[118] The 2024 ACC converted month-hour average EUE values to 8,760 capacity allocation factors using temperature data by: calculating a load-weighted daily maximum statewide temperature using typical weather year data used in the 2022 building code cycle; assigning month-hour average EUE values from SERVM for all hours within days on which the maximum temperature exceeds a specific temperature

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[116] Revised Staff Proposal at 10.

[117] Revised Staff Proposal at 10.

[118] Revised Staff Proposal at 10.

threshold; and assigning a value of zero for days with a maximum temperature below the threshold. Capacity allocation factors were then normalized to sum to 1.0 over the full year.[119]

11.1. Using Loss of Load Hours Rather than EUE for Generation Capacity Allocation Factors

The Staff Proposal suggests modifying the hourly allocation of generation capacity value by using loss of load hours (LOLH) rather than EUE as the basis for the allocation factors. The proposal explains that EUE measures the magnitude of unserved energy, which places greater weight on hours in which system shortfalls are larger rather than hours with smaller shortfalls.[120] That approach concentrates capacity value allocation in hours where the magnitude of unserved energy is the largest. However, the value of a small increase or decrease in load (the marginal value) does not depend on whether the system shortfall is small versus large in any given hour. The reliability benefit of a marginal change in load is the same across all hours with a loss of load, regardless of the magnitude of the loss of load event.[121] The Staff Proposal thus suggests using LOLH to calculate the ACC capacity allocation factor, which would measure the frequency rather than the magnitude of such loss of load events.[122]

Cal Advocates, SDG&E, and PG&E support modifying the hourly allocation of generation capacity value by using LOLH rather than EUE as the basis for the allocation factors. Cal Advocates states that "[a]ny marginal loss of

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[119] Revised Staff Proposal at 10.

[120] Revised Staff Proposal at 11.

[121] Revised Staff Proposal at 11.

[122] Revised Staff Proposal at 11.

load hour has an equivalent marginal reliability value, since a single MWh of load reduction has the same reliability benefit for any hour that has a loss of load, regardless of the magnitude of the loss of load."[123] SDG&E states that EUE factors are sensitive to a small population of high-magnitude events and can substantially shift weights placed on individual hours while the modification aligns with the Commission's adopted reliability planning standard using LOLH rather than EUEs.[124] PG&E states that the modification will help spread DER response across a wider set of hours than using EUE.[125]

CUE states that it supports the proposal in concept and that an allocation method based only on the magnitude of unserved energy can over-concentrate value in a smaller number of extreme events.[126] However, CUE states that the Energy Division and E3 should provide more hourly allocation detail before the Commission approves the proposal.

Bay-REN and 3C-REN state that the Commission should defer a decision on this issue until it issues a decision on ACC guiding principles in Track 3 of this proceeding.[127]

SEIA, SCE, CLECA, SDG&E, and SBUA take no position on using LOLHs rather than EUE as the basis for the allocation factors.

The Commission agrees with the Staff Proposal that using LOLH rather than EUE as the basis for the generation capacity value allocation will better reflect the reliability benefit of a generation resource across all hours rather than

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[123] Cal Advocates Opening Comments at 10.

[124] SDG&E Opening Comments at 4-5.

[125] PG&E Opening Comments at 3.

[126] CUE Opening Comments at 13-14.

[127] BayREN and 3C-REN Opening Comments at 5.

focusing on hours with the greatest amount of unserved energy. The Staff Proposal and accompanying ACC model provide enough detail about the proposed LOLH methodology to approve its adoption in the ACC. Accordingly, this decision updates the ACC to use LOLH rather than EUEs to allocate generation capacity value.

11.2. Using Energy Prices Rather than Temperature to Assign Days with High Generation Capacity Value

The Staff Proposal suggests modifying the method for 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. The proposal states that the current approach of assigning the generation capacity values to the hottest days reflects historical energy system dynamics in which the days of greatest reliability concern typically aligned with high temperatures.[128] The proposal, however, notes that the combination of increasing winter loads due to building electrification and the growing penetrations of renewables is shifting reliability risks from summer to winter months.[129] Other metrics, such as energy prices, better reflect the timing of loss-of-load events within the year, when the balance between supply and demand is most constrained, according to the Staff Proposal.[130]

Therefore, staff recommend that the ACC adopt hourly energy prices from SERVM, rather than temperature, to identify days of greatest grid constraints, as energy prices capture both supply and demand dynamics and scarcity of

[128] Revised Staff Proposal at 11.

[129] Revised Staff Proposal at 12.

[130] Revised Staff Proposal at 12.

available generation.[131] Days within each month with high energy prices would be used to allocate non-zero capacity allocation hours using month-hour average outputs developed from reliability modeling.[132]

Cal Advocates, PG&E, and CUE support modifying the method for assigning month-hour averages of generation capacity values from the days with the highest temperatures to the days with highest energy prices.

Bay-REN and 3C-REN state that the Commission should defer a decision on this issue until it issues a decision on ACC guiding principles in Track 3 of this proceeding.[133]

SEIA, SCE, CLECA, SDG&E, SoCalGas, NRDC, and SBUA take no stand on modifying the method for assigning month-hour averages of generation capacity values.

The Commission agrees with the Staff Proposal that 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. Accordingly, this decision updates the ACC to adopt hourly energy prices from SERVM, rather than temperature, to identify days of greatest grid constraints.

[131] Revised Staff Proposal at 12.

[132] Revised Staff Proposal at 12.

[133] BayREN and 3C-REN Opening Comments at 5.

11.3. Representing Reliability Risk Difference of Weekdays Versus Weekends in Capacity Value Allocation

The Staff Proposal suggests allocating days with non-zero reliability risk to weekends and weekdays so that the final capacity value allocation aligns with the weekend/weekday risk from reliability modeling.[134]

The ACC currently does not take into account differences in reliability risk on weekends compared to weekdays although reliability modeling has shown that weekdays typically have significantly higher reliability risk than weekends.[135] Already, several end-uses of the ACC do consider the differences between weekends and weekdays such as the DER profiles used in cost-effectiveness evaluation and the export rates in the Net Billing Tariff.[136]

Cal Advocates, SDG&E, and PG&E support differentiating between weekends and weekdays when allocating reliability risk.

CUE supports differentiating between weekends and weekdays when allocating reliability risk but states that the Commission should demand more detail about hourly allocation factors from Energy Division and E3 before approving the proposal.

SEIA, SCE, CLECA, SDG&E, SBUA, NRDC, Bay-REN, and 3C-REN take no stand on the issue.

The Commission agrees with the Staff Proposal that taking into account differences in reliability risk on weekends compared to weekdays in the ACC model will better reflect the results of reliability modeling that show weekdays

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[134] Revised Staff Proposal at 13.

[135] Revised Staff Proposal at 13.

[136] Revised Staff Proposal at 13.

have significantly higher reliability risk than weekends. Accordingly, this decision updates the ACC to account for reliability risk differences on weekdays and weekends.

12. Refining the Hourly Allocation of Transmission Capacity Value

The Staff Proposal suggests updating the peak capacity allocation factors (PCAFs) used to calculate the hourly allocation of transmission capacity value by calculating the PCAFs with IEPR load forecasts for future years instead of historical loads.[137]

The 2024 ACC Update calculated the PCAFs by using historical system-level hourly loads from the CAISO Energy Management System dataset that were then adjusted to align with the typical weather year represented by the ACC.[138] The same PCAFs were applied to all years, assuming that the hours of constrained transmission capacity will stay static.[139] However, the IEPR load forecasts indicate that the hours of constrained transmission capacity will evolve due to increasing penetration of electric vehicles and building electrification and increasing behind-the-meter generation. Therefore, staff propose using those IEPR load forecasts to update the PCAF calculations for transmission capacity allocation to better represent the hours in which DERs are expected to provide transmission capacity value in the future and to better align with energy avoided costs and generation capacity allocation factors currently used in the ACC.[140]

[137] Revised Staff Proposal at 13.

[138] Revised Staff Proposal at 13.

[139] Revised Staff Proposal at 13.

[140] Revised Staff Proposal at 13.

Cal Advocates supports estimating the hourly allocation of transmission capacity value by calculating the PCAFs with IEPR load forecasts for future years instead of historical loads. Cal Advocates states that using the IPER load forecasts provides a more updated, dynamic estimate of the avoided cost value of marginal distributed resources on the transmission grid.[141]

BayREN and 3C-REN state that the Commission should defer a decision on this issue until it issues a decision on ACC guiding principles in Track 3 of this proceeding.

CUE states that the proposal appears to be "directionally reasonable" but that more workpapers and impact analysis are needed for the Commission to adopt the proposal.[142]

SEIA, SCE, CLECA, SDG&E, PG&E, SBUA, SoCalGas, and NRDC take no stand on the issue.

The Commission agrees with the Staff Proposal that calculating the PCAFs with IEPR load forecasts for future years instead of historical loads will better capture the hourly allocation of transmission capacity value due to increasing transportation electrification and behind-the-meter generation. While BayREN and 3C-REN urge the Commission to postpone updating the PCAF methodology until guiding principles are defined in Track Three of this proceeding, they do not specify how the outcome of Track Three would impact the PCAF methodology specifically compared to the other updates suggested in the Staff Proposal. Without such specificity, the Commission cannot delay the 2026 ACC update cycle until guiding principles are defined and implemented.

[141] Cal Advocates Opening Comments at 12.

[142] CUE Opening Comments at 17.

Additionally, any ACC guiding principles adopted in Track Three can be applied to the next biannual ACC update. Accordingly, this decision updates the ACC to calculate the PCAFs with IEPR load forecasts for future years, as used in SERVM modelling for calculating energy avoided costs, instead of historical loads.

13. Alignment of Transmission Avoided Cost Calculations Across Utilities.

The Revised Staff Proposal suggests using only the Discounted Total Investment Method (DTIM) to calculate marginal transmission costs for SCE, rather than the combination of the DTIM and the Locational Net Benefits Analysis (LNBA) which had been applied for SCE since the 2020 ACC update cycle.[143] The DTIM is generally applied for system-wide capacity-driven transmission investments while the LNBA is 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.[144] Transmission values for PG&E and SDG&E were already calculated using only the DTIM in prior cycles. In prior cycles, Energy Division staff calculated transmission value for SCE using both the DTIM and LNBA because SCE provided costs and capacity needs for individual large projects as well as system-wide investments.[145] With the staff proposal to use only the DTIM method for SCE, the capacity needs and investment associated with any large projects would be folded into the overall system-wide capacity needs and investment.[146] The proposed method would improve consistency in the calculations across electric utilities and reduce

[143] Revised Staff Proposal at 14.

[144] Revised Staff Proposal at 14.

[145] Revised Staff Proposal at 14.

[146] Revised Staff Proposal at 14.

volatility in the transmission value tied to the impacts of individual large projects.[147]

SCE supports the adoption of the transmission avoided cost calculation method for all electric utilities only for the 2026 ACC Update, stating that it has not been able to fully investigate the impacts of retiring the LNBA method on a permanent basis.[148] SCE also writes that it expects the one remaining LNBA transmission project to shift to the DTIM for 2026.[149]

SDG&E does not oppose or support the transmission avoided cost calculation method but states it "does not oppose a revision that is transparent, grounded in verifiable planning information, and sufficiently documented to permit stakeholder review."[150]

Clean Coalition states that the Commission should require the 2026 ACC workpapers to clearly identify which SCE large transmission projects are included in the DTIM calculation, which projects are excluded and why, how capacity need is calculated, and how the resulting DTIM-only value compares to the prior combined DTIM/LNBA value.[151]

SEIA does not oppose the standardization of the transmission avoided cost calculation across all electric IOUs but recommends that SCE and SDG&E's DTIM calculations of avoided transmission costs use the same criteria adopted by PG&E to determine which future transmission projects are capacity-related.[152]

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[147] Revised Staff Proposal at 14.

[148] SCE Opening Comments on June 5 Ruling at 4.

[149] SCE Opening Comments on June 5 Ruling at 4.

[150] SDG&E Opening Comments on June 5 Ruling at 2.

[151] Clean Coalition Opening Comments on June 5 Ruling at 2.

[152] SEIA Opening Comments on June 5 Ruling at 10-11.

SEIA also recommends parties be allowed to provide feedback on the cost data to be used for the marginal transmission costs in the 2026 ACC.[153]

SoCalREN, PG&E, SoCalGas, SBUA, and CLECA do not take a position on the transmission avoided cost calculation.[154]

The Commission agrees with SCE that all electric IOUs should be required to use the DTIM-only transmission avoided cost calculation. The Commission agrees with the Revised Staff Proposal that adopting the proposed DTIM-only approach will improve consistency in calculations across utilities and maintain the use of a DTIM-only approach that has been approved and used in recent ACC cycles.[155] Responding to Clean Coalition's suggestion that the Commission require that the 2026 ACC work papers clearly identify which SCE large transmission projects are included in the DTIM calculation, the Commission declines to specify particular contents of the workpapers in this decision. Accordingly, this decision adopts the DTIM-only transmission avoided cost calculation for all electric utilities in the 2026 and future ACC cycles.

14. Party Proposals Related to the Avoided Cost Calculator

SEIA, SCE, Cal Advocates, CLECA, BayREN, 3C-REN, and CUE all state that parties did not receive enough time and information to thoroughly evaluate the proposed changes within the proceeding schedule. The parties request more time as well as another round of comments and additional workshops on the

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[153] SEIA Opening Comments on June 5 Ruling at 10-11.

[154] SoCalREN Opening Comments on June 5 Ruling at 6, PG&E Opening Comments on June 5 Ruling at 1, SoCalGas Opening Comments on June 5 Ruling at 2, SBUA Opening Comments on June 5 Ruling at 1, CLECA Opening Comments on June 5 Ruling at 13.

[155] Revised Staff Proposal at 15.

proposed ACC modifications.[156] PG&E proposes adopting a schedule similar to that followed in the Resource Adequacy proceeding, which gathers stakeholder ideas, allows them to present their ideas in workshops, and includes a formal comment process on those proposals.[157]

BayREN and 3C-REN propose that Energy Division publish a side-by-side comparison of current 2024 ACC GHG values, proposed 2026 ACC GHG values, and 2026-2027 TPP RESOLVE shadow prices before adopting GHG methodology changes.[158] BayREN and 3-C Ren also suggest that the Commission publish the Integrated Calculation's GHG output and allow for party comment before a final calculation method is adopted.[159]

15. Timeline of 2026 Avoided Cost Calculator Update

The updates to the ACC methodology, as described in the Conclusions of Law in this decision, are adopted.

Energy Division will release a draft 2026 ACC after the proposed decision is issued and hold a workshop on the draft 2026 ACC. The workshop discussions and subsequent party comments will be considered in a Commission resolution approving the 2026 ACC. The 2026 ACC will be effective upon approval of the resolution approving the 2026 ACC.

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[156] SCE Opening Comments at 13-15, Cal Advocates Opening Comments at 2-4, CLECA Opening Comments 2-4, CLECA Reply Comments at 3-5, SEIA Opening Comments, at 16-19, SEIA Reply Comments at 6, BayREN and 3C-REN Opening Comments at 3-5, CUE Opening Comments 10-13 and 15-18, CUE Reply Comments at 3 and 14-17, PG&E Reply Comments at 1-2, CLECA Reply Comments on June 6 Ruling at 3.

[157] PG&E Reply Comments at 2.

[158] Bay REN and 3C-REN Reply Comments at 8.

[159] BayREN and 3-C Ren Opening Comments on June 5 Ruling at 4.

16. Summary of Public Comment

Rule 1.18 of the Rules of Practice and Procedure allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

No relevant public comments were received in the docket of this proceeding as of the date of submission of the record for this decision.

17. Procedural Matters

This decision affirms all rulings made by the Administrative Law Judge and the assigned Commissioner in this proceeding. All motions related to the issues in this decision not ruled on are deemed denied.

18. Comments on Proposed Decision

The proposed decision of ALJ Jack Chang in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

19. Assignment of Proceeding

Darcie L. Houck is the assigned Commissioner, and Jack Chang is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The state of California lacks a cross-sector basis for valuing GHG reductions.

2. The state of California has not developed sector-specific modeling of marginal abatement costs for the natural gas sector beyond the current interim value based on a 2021 CEC report on the GHG abatement cost in buildings.

3. The electric sector GHG value is more frequently updated than the natural gas sector GHG interim value currently used in the ACC.

4. Using an electric sector GHG value for all GHG reductions in the ACC model aligns with the marginal GHG value indicated by the IRP.

5. Adopting the electric-sector GHG value for all GHG reductions would provide a coherent basis for evaluating emissions reductions across the electric and gas sectors.

6. Avoiding the overvaluation of GHG reduction measures by adopting an electric-sector GHG value for all GHG reductions is in the ratepayer interest.

7. The GHG rebalancing component of the ACC was introduced to account for the reallocation of allowable GHG emissions across electric and gas sectors.

8. Removing the GHG rebalancing component aligns the GHG value in the ACC with the GHG value in the IRP.

9. Using the IRP GHG avoided cost "shadow price" in the ACC would align the IRP and ACC.

10. Adopting a simplified Integrated Calculation using a hybrid energy resource and the GHG avoided cost shadow price from the IRP model to calculate avoided generation capacity costs will help provide a consistent method across the ACC and IRP proceedings.

11. A small versus large amount of load reduction during an hour results in the same reliability benefit across all hours with a loss of load.

12. Using LOLH to calculate the ACC capacity allocation factor would measure the frequency rather than the magnitude of such loss of load events.

13. The combination of increasing winter loads due to building electrification and the growing penetrations of renewables is shifting reliability risks from summer to winter months due to higher winter loads and lower renewable output during winter months.

14. Energy prices, compared to temperature, better reflect the timing of loss-of-load events within the year, when the balance between supply and demand is most constrained.

15. Reliability modeling has shown that weekdays typically have significantly higher reliability risks than weekends.

16. Differentiating between weekends and weekdays when allocating days with non-zero reliability risk enables the final capacity value allocation to align with the weekend/weekday risk from reliability modeling.

17. IEPR load forecasts indicate that the hours of constrained transmission capacity will evolve due to increasing penetration of electric vehicles and building electrification and increasing behind-the-meter generation.

18. Using IEPR load forecasts to update the PCAF calculations for transmission capacity allocation better represent the hours in which DERs are expected to provide transmission capacity value and better align with energy avoided costs and generation capacity allocation factors currently used in the ACC.

19. Using a DTIM-only method to measure marginal transmission costs for all electric utilities would improve consistency in the calculations across utilities and reduce volatility in the transmission value tied to the impacts of individual large projects.

Conclusions of Law

1. The ACC should be updated to apply a single electricity-based value to represent both electricity and natural gas GHG values in the ACC.
2. The ACC should be updated to remove the GHG rebalancing component.
3. The ACC should not be updated to implement a cap on the GHG value in both electric and gas models equal to the high societal cost of carbon adopted in the Societal Cost Test.
4. The ACC should be updated to implement a simplified Integrated Calculation to address transparency and sensitivity to minor inconsistencies between RESOLVE and SERVM models.
5. The ACC should be updated to use LOLH rather than EUE as the basis for ACC capacity allocation factors.
6. The ACC should be updated to use energy prices rather than temperature to calculate high generation capacity values to better reflect increased electricity use in both summer and winter months.
7. The ACC should differentiate between weekends and weekdays when allocating days with non-zero reliability risk to align with weekend/weekday reliability risk indicated in reliability modelling.
8. The ACC should be updated so that the PCAF calculations for transmission avoided costs uses the IEPR load forecast for future years, as used in SERVM modelling for calculating energy avoided costs, instead of historical loads.
9. The ACC should be updated to use a DTIM-only method to calculate marginal transmission costs for all electric utilities.

10. It is reasonable to continue to use the current methodology and the most current transmission and distribution cost data to calculate avoided transmission and distribution costs in the ACC.

11. Except as explicitly provided in the Conclusions of Law of this decision, it is reasonable to apply the methodologies approved in the 2024 ACC Decision to the ACC.

12. It is reasonable to affirm all rulings made by the assigned ALJ or the assigned Commissioner related to the issues considered in this decision.

13. It is reasonable to deny all motions related to the issues considered in this decision that were not ruled on.

O R D E R

IT IS ORDERED that:

1. The updates to the Avoided Cost Calculator methodology described in the Conclusions of Law of this decision are adopted.

2. All rulings made by the assigned Administrative Law Judge or the assigned Commissioner related to the issues considered are affirmed.

3. All motions related to the issues considered in this decision that were not ruled on are denied.

4. Rulemaking 22-11-013 remains open.

This order is effective today.

Dated _____, at Sacramento, California.