2024 Distributed Energy Resources Avoided Cost Calculator Documentation

For the California Public Utilities Commission

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~~https://willdan.box.com/v/2024CPUCAvoidedCosts~~https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

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1 Introduction

This document describes the inputs, assumptions and methods used in the 2024 Distributed Energy Resources (DER) Avoided Cost Calculator (ACC). The DER ACC model, documentation and supporting files are available at:

- https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm , and
- https://www.ethree.com/public_proceedings/energy-efficiency-calculator/, and
- https://willdan.box.com/v/2024CPUCAvoidedCosts

Decision (D.)19-05-019 in the Integrated Distributed Energy Resources (IDER) proceeding, R.14-10-003, initiated a process to implement major and minor updates to the Distributed Energy Resources (DER) Avoided Cost Calculator (ACC) in 2020. This process culminated in a Staff Proposal (ACC Staff Proposal) for the 2020 ACC update that was adopted in D.20-04-010. The 2020 ACC update implemented major changes in the CPUC's approach to estimating the avoided costs of distributed energy resources – most importantly, changes to align the ACC with the integrated resources and distribution planning processes. Since then, ACC updates have been implemented in 2022 and now in 2024, with the 2024 updates summarized below.

The ACC is used to determine the benefits of Distributed Energy Resources (DER), such as energy efficiency and demand response, for cost-effectiveness analyses. The ACC is the first part of the three-part cost-effectiveness process used by the CPUC to determine the costs and benefits of customer programs[1]. The ACC estimates hourly, system-level costs of providing electric or gas service for 30 years, in $/kWh or $/therm. These hourly avoided costs are used with specific program data, such as hourly energy savings, to determine program benefits. Those benefits are then compared to program costs to determine cost-effectiveness.

Two additional uses of the ACC have been introduced in recent years. D.21-05-031 implemented the Total System Benefit (TSB) test for setting EE portfolio goals. The TSB uses avoided costs to represent the total present value lifecycle benefits of EE programs and will replace kWh, kW and therms as the primary goal for EE program portfolios. A December 13, 2021 proposed decision in the Net Energy Metering (NEM) successor tariff proceeding (R. 20-08-020) adopts the ACC as the basis for setting export compensation for behind-the-meter NEM PV.[2]

The ACC includes an electric avoided cost calculator and a natural gas avoided cost calculator (including an avoided natural gas infrastructure calculator). The ACC determines several types of avoided costs including avoided generation capacity, energy, ancillary services, greenhouse (GHG) emissions, high global warming potential gases, transmission and distribution capacity, and natural gas infrastructure.

[1] This three-part process is described in the "Cost-Effectiveness Brief Overview," available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm

[2] A subsequent May 9, 2022 ruling reopened the evidentiary record and invited party comments on a limited basis to explore three elements of the proposed decision.

Since 2020, the ACC has been closely aligned with the grid planning efforts of the Integrated Resource Planning (R. 16-02-007) and distribution planning proceedings. The avoided costs are based on data and analysis from Integrated Resource Planning (IRP) modeling, except for the avoided costs of transmission and distribution, which are based on data and guidance from the distribution planning proceeding. The 2020 ACC was also updated to fully support evaluation of electrification measures that increase load but may decrease total GHG emissions. This includes adopting a new avoided cost of high global warming potential (GWP) gases, which value the GHG impacts of distributed energy resources (DERs) on methane and refrigerant leakage.[3] The 2022 ACC adopted another new avoided cost – the avoided gas infrastructure cost (AGIC), which measures the value that new, all-electric construction provides in avoiding natural gas infrastructure.

The ACC also provides hourly ancillary service price forecasts from the SERVM reliability and production simulation model used in the IRP proceeding. Ancillary services are a potential benefit for dispatchable DER that can provide reserves in CAISO markets. This is different than the avoided ancillary service cost that estimates the value that DER provides to avoid procuring spinning reserves when load is reduced. The ACC's hourly values have been used to determine the *increased* costs incurred by electrification programs that increase electric load. D.22-05-002 adopted the use of the ACC to determine increased, as well as decreased marginal costs.

1.1 Summary of Updates for 2024 ACC

Changes to methodology for the 2024 ACC were proposed by Energy Division Staff in a Staff Proposal published in August, 2023[4]. On June 26, 2024, the CPUC published a Proposed Decision on the Staff Proposal which would adopt many of the changes proposed in the Staff Proposal.[5] The 2024 ACC reflects the proposed changes in the Proposed Decision, including the following key updates:

- Using the IRP's latest adopted system plan as the baseline portfolio of resources, instead of the No New DER portfolio which was used in previous ACC releases
- Calculating generation capacity and GHG avoided costs with an integrated calculation that accounts for the interdependence of these avoided costs
- Using updated logic for the dispatch of storage resources in SERVM reliability modelling which is used for hourly generation capacity value allocation
- Performing additional calibration and benchmarking of SERVM based on historical CAISO market outcomes to improve the accuracy of SERVM outputs

[3] For electrification measures, the cost categories for delivering electricity for added load are not a benefit or 'avoided' cost, but an added cost. Reduced use of natural gas and GWP gases are avoided costs for electrification measures.

[4] Integrated Distributed Energy Resources (IDER) 2024 Avoided Cost Calculator (ACC) Staff Proposal, August 8, 2023, R.22-11-013, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M516/K712/516712053.PDF

[5] Proposed Decision Adopting Changes to the Avoided Cost Calculator, June 26, 2024, R.22-11-103, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M534/K536/534536268.PDF

In addition, the 2024 ACC also includes a Societal Cost Test (SCT) option in response to the Decision Adopting the Societal Cost Test mailed May 24, 2024 (R.22-11-013) for both Electric and Gas models. The SCT implements a social cost of carbon (SCC), societal discount rate, national-average methane leakage adder, and air quality adder, as detailed in Section 11.

Table 1-1 summarizes the primary data sources and major differences between methods used in the 2022 and 2024 ACCs. Additional details of methodology changes are provided for each component in the respective sections of this document. Additional details of data sources used in the 2024 update are summarized in Table .

Table 1-1. Major Changes between 2022 and 2024 ACC Updates

Avoided Cost	2022 ACC	2024 ACC	Data Source
Generation Capacity	Battery Storage Real Economic Carrying Charge (RECC)	Integrated Calculation of Gen Cap and GHG Avoided Costs	RESOLVE inputs & outputs, SERVM outputs
Energy	RESOLVE No New DER and SERVM modeling	RESOLVE PSP and SERVM modeling	SERVM outputs
Ancillary Services	RESOLVE No New DER and SERVM modeling	RESOLVE PSP and SERVM modeling	SERVM outputs
GHG Value	Based on RESOLVE GHG shadow price and cap & trade	Integrated Calculation of Gen Cap and GHG Avoided Costs	RESOLVE inputs & outputs, SERVM outputs
GHG Emissions	SERVM short- run marginal emissions and RESOLVE long-run grid emissions intensity	SERVM short- run marginal emissions and RESOLVE long-run grid emissions intensity	RESOLVE and SERVM outputs, cap & trade prices, annual GHG electric sector goals
Transmission	From Transmission Planning	From Transmission Planning	GRC filings, IEPR forecasts, and historical utility cost and financial data
Distribution	From Distribution Planning	From Distribution Planning	GNA and DDOR data
High GWP gases	Methane & refrigerant leakage modeling	Methane & refrigerant leakage modeling	CARB data
Avoided Gas Infrastructure	From utility filings	From utility filings	Utility data

Table 1-2. Summary of 2024 ACC Update

Input	2024 Update	Data Source
RESOLVE PSP Portfolio	Load and DER Forecasts	Final 2022 CEC IEPR Load Forecasts
	PSP Portfolio	2023 CPUC IRP RESOLVE Capacity Expansion Modeling
IRP Proceeding Inputs	Natural Gas Prices	CEC Power Plant Burner Tip Price Model, 2023 Preliminary Model
	Cost of Solar & Energy Storage	2023 CPUC IRP RESOLVE Resource Costs and Build Inputs
	Weighted Average Cost of Capital	CPUC Authorized Rate of Return for 2023
SERVM Production Simulation	Updated SERVM Model from Astrapé	Run with PSP Portfolio from CPUC IRP
Natural Gas Avoided Cost	CEC IEPR Natural Gas Prices	CEC Power Plant Burner Tip Price Model, 2023 Preliminary Model
	Transportation Rates Forecasts	CEC Power Plant Burner Tip Price Model, 2023 Preliminary Model
Energy	Implied Marginal Heat Rate	Recalculated From SERVM Production Simulation based on CEC IEPR Natural Gas Price forecasts
	Updated Scarcity Pricing Methodology	Scarcity pricing methodology updated. Scarcity pricing calculated within SERVM Production Simulation
	Day Ahead Hourly Energy Prices	SERVM Production Simulation
Ancillary Services	AS Prices	SERVM Production Simulation
	Avoided AS Procurement	Recalculated with SERVM Production Simulation Results
Generation Capacity	Generation Capacity	Calculated with Integrated Calculation of Generation Capacity and GHG avoided costs model
GHG Value	GHG Value	Calculated with Integrated Calculation of Generation Capacity and GHG avoided costs model
	Cap and Trade Value	CED 2022 Update GHG Allowance Price Projections
GHG Emissions	Updated Heat Rates from SERVM Modeling	Implied Market Heat Rates from CPUC SERVM Production Modeling

Input	2024 Update	Data Source
	Average Annual Grid GHG Emissions Intensity	2023 CPUC IRP RESOLVE Capacity Expansion Modeling
Transmission	Update Transmission Allocation Factors	Transmission PCAFs calculated from 2023 CAISO load data for each utility
	Update Marginal Transmission Capacity Cost	Utility GRC Phase II filings and Loading Factor Inputs, Transmission Project Costs and Loading Factor inputs, and CEC IEPR
Distribution	Update Marginal Distribution Allocation Factors	Distribution PCAFs provided by PG&E and SCE; PCAFs for SDG&E calculated using utility distribution load data
	Update Marginal Distribution Capacity Costs	Utility 2023 GNA and DDOR reports for near term, GRC filings for long term and marginal cost factors

A summary comparison of 20-year levelized avoided costs from the 2022 and 2024 ACC electric models are shown for PG&E, Climate Zone 12 (Sacramento) for a 2024 resource is shown in Figure 1-1 through Figure 1-4 (in 2024 dollars). Note that while an Air Quality Adder label is now included in the legend for the 2024 electric model, this component only applies to the SCT and its value is zero under the Total Resource Cost (TRC) version of the model compared in these figures. As explained further in the rest of this document, some key changes in avoided costs from the 2022 ACC to the 2024 ACC are as follows:

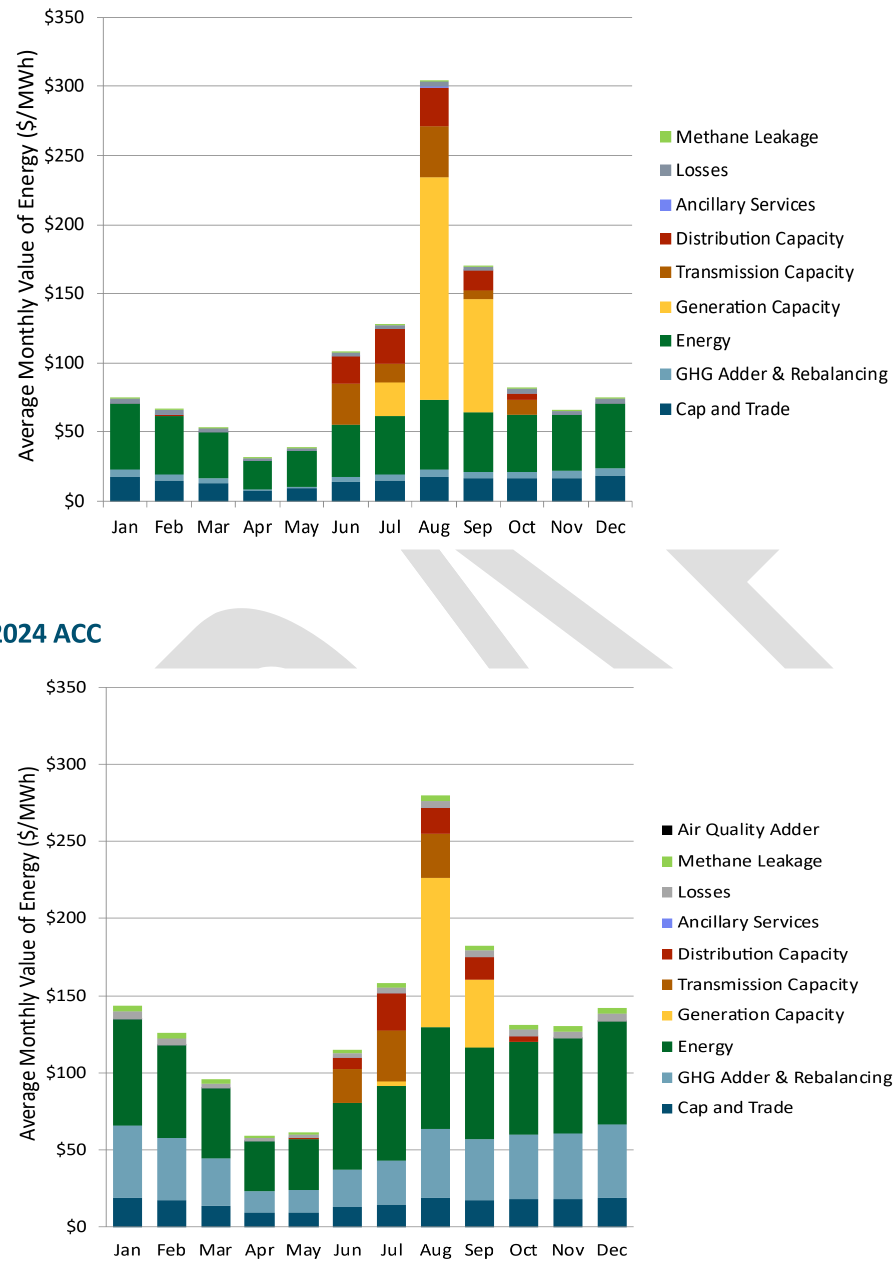
- GHG value increases significantly after 2028 relative to the 2022 ACC, which implicitly reflects the incremental costs of renewable and storage resources needed to continue progress towards the state's long-term decarbonization goals. Contributing to the increased GHG value are the increasing stringency of state's GHG planning targets (25MMT compared to 30 MMT), recent cost increases for solar and storage, and the declining marginal energy value and emissions impacts of solar resources at higher penetrations based on SERVM modelling for the 2024 ACC.
- Capacity value is high in the near-term (though lower than values developed in the 2022 ACC) and declines to a level set by the assumed fixed cost of a natural gas resource.
- Capacity value is spread out across a broader period in the summer, better capturing the windows in which additional energy can provide a reliability benefit to the system as the growing penetration of energy storage allow for energy to be shifted to the periods of greatest need.
- Energy value is lower during solar hours and higher outside of solar hours.
- Near-term distribution avoided costs are lower for all utilities. This is partly tied to a refinement in the marginal cost calculations to better align with the approved T&D White Paper methodology and only include incremental, DER-deferred overloads, rather than those expected to be deferred by planned investments. The calculations are now also performed separately for circuits experiencing load increases and those experiencing load reductions from DERs. The prior approach to group these has become increasingly sensitive to minor forecast differences and would result in a negative avoided cost value.

- Transmission avoided costs for SCE have increased. This change is due primarily to large expenditures associated with the Wildlife substation upgrade project.
- Transmission avoided costs are lower for SDG&E – now comparable to the other two utilities - based on reduced transmission expenditures and increased demand forecasts. The calculation now takes into account a longer demand forecast period based on available data. This better aligns expenditures with the period of load growth they address and helps mitigate fluctuation due to 'lumpy' transmission spend.

Natural gas avoided costs have only minor changes from the 2022 ACC.

Figure 1-1. Average Monthly Avoided Costs (PG&E Climate Zone 12, 20-year levelized value of 2024 resource)

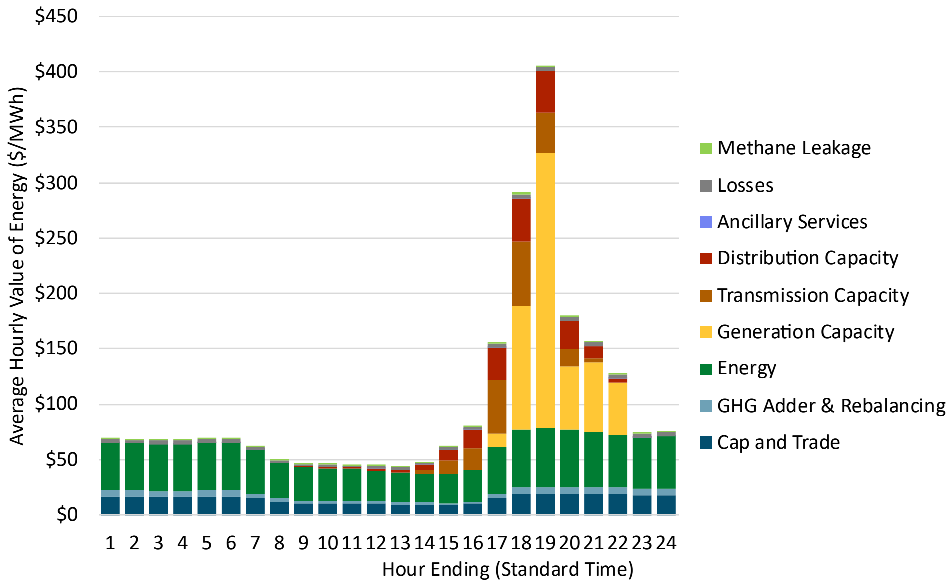
2022 ACC



2024 ACC

Figure 1-2. Average Hourly Avoided Costs (PG&E Climate Zone 12, 20-year levelized value of 2024 resource)

2022 ACC



2024 ACC

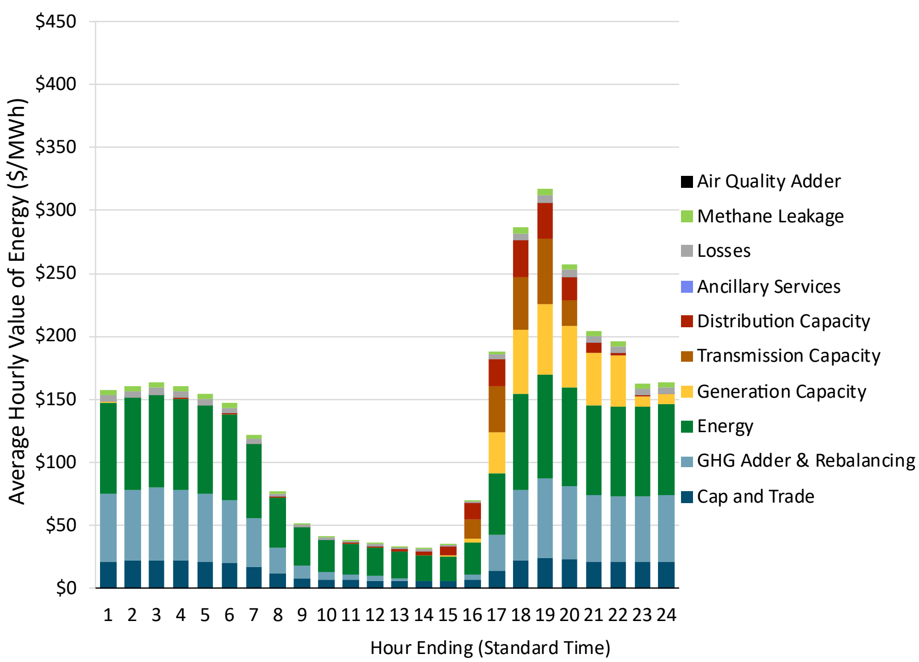
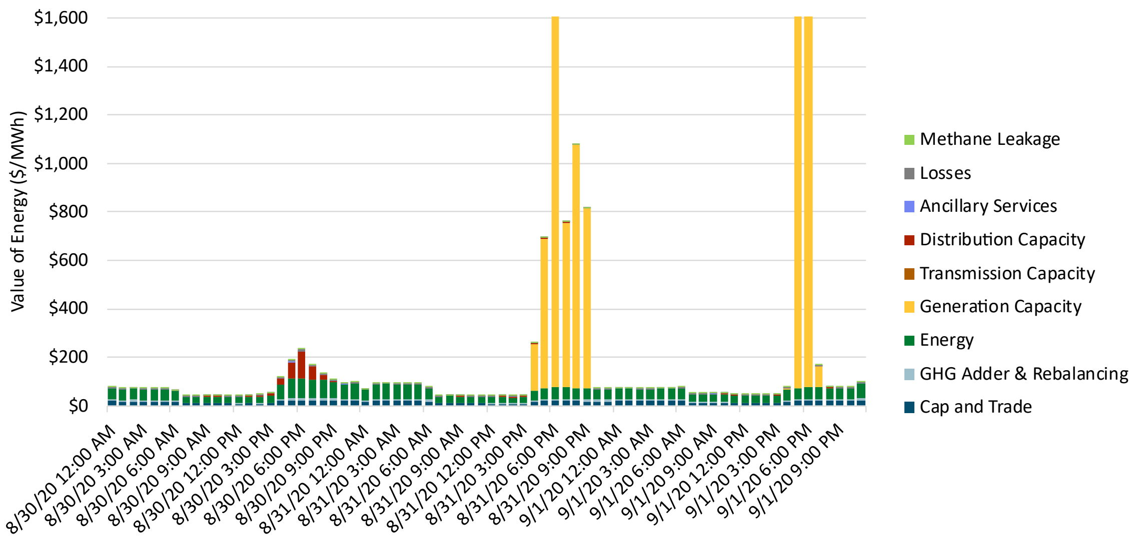
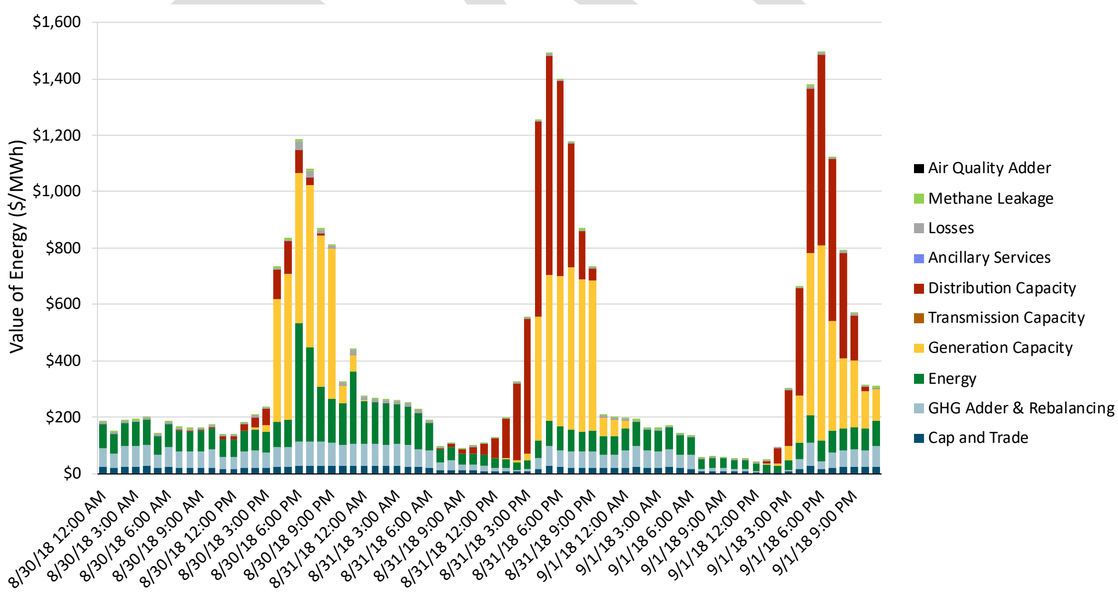


*Figure 1-3. Hourly Avoided Costs for Three Days Beginning August 30th (PG&E Climate Zone 12, 20-year levelized value of 2024 resource)**

2022 ACC



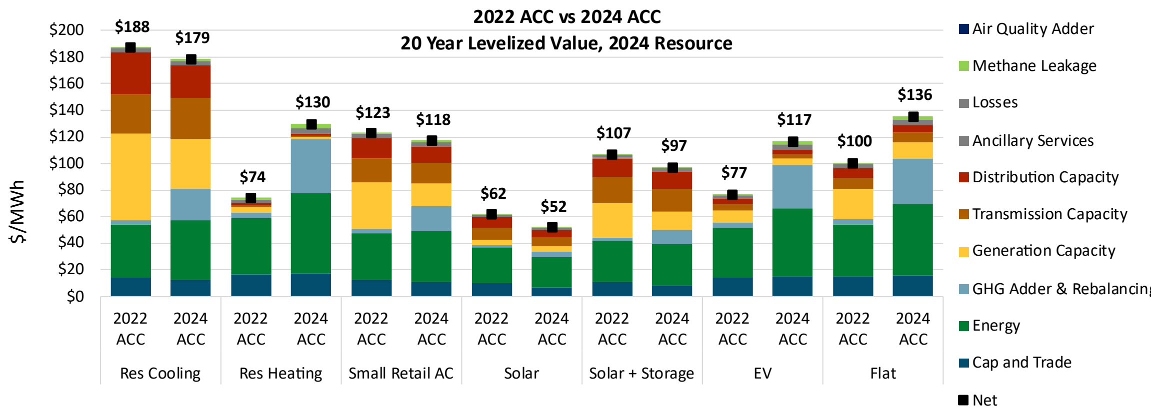
2024 ACC



**Vertical axis is capped at $1,600/MWh. 2022 ACC capacity value extends to $3000/MWh on September 1, 2020). Also note that the 2022 ACC uses a 2020 calendar year and the 2024 ACC uses a 2018 calendar year. This impacts the alignment with the weather year and therefore the T&D allocation factors on each calendar day. High distribution costs in the 2024 ACC on the selected days illustrate how this variance can impact specific days though the 20-year levelized costs have not changed significantly.*

Annual average 20-year levelized avoided costs for a 2024 resource from the 2022 ACC and 2024 ACC are shown for selected end-use electric load shapes in Figure 1-4. The load shapes are end uses (not measure-specific impacts) for selected loads or generation (e.g., solar) types. "Flat" refers to use of a shape that has the same consumption in all hours to reflect a simple average avoided costs across all hours.

Figure 1-4. Average Annual Avoided Cost for Illustrative Normalized Load Shapes (PG&E Climate Zone 12, 20-year levelized value for 2024 resource)



1.2 Flow Charts of Information Used in ACC

Figure 1-5 details the flow of data from IRP, Distribution Planning proceedings, and data sources such as the California Energy Commission (CEC) Integrate Energy Policy Report (IEPR), various California Air Resource Board (CARB) databases, and data from the California Independent System Operator (CAISO). Figure 1-6 shows the flow of inputs and calculations in the ACC.

Figure 1-5. Avoided Cost Process Overview

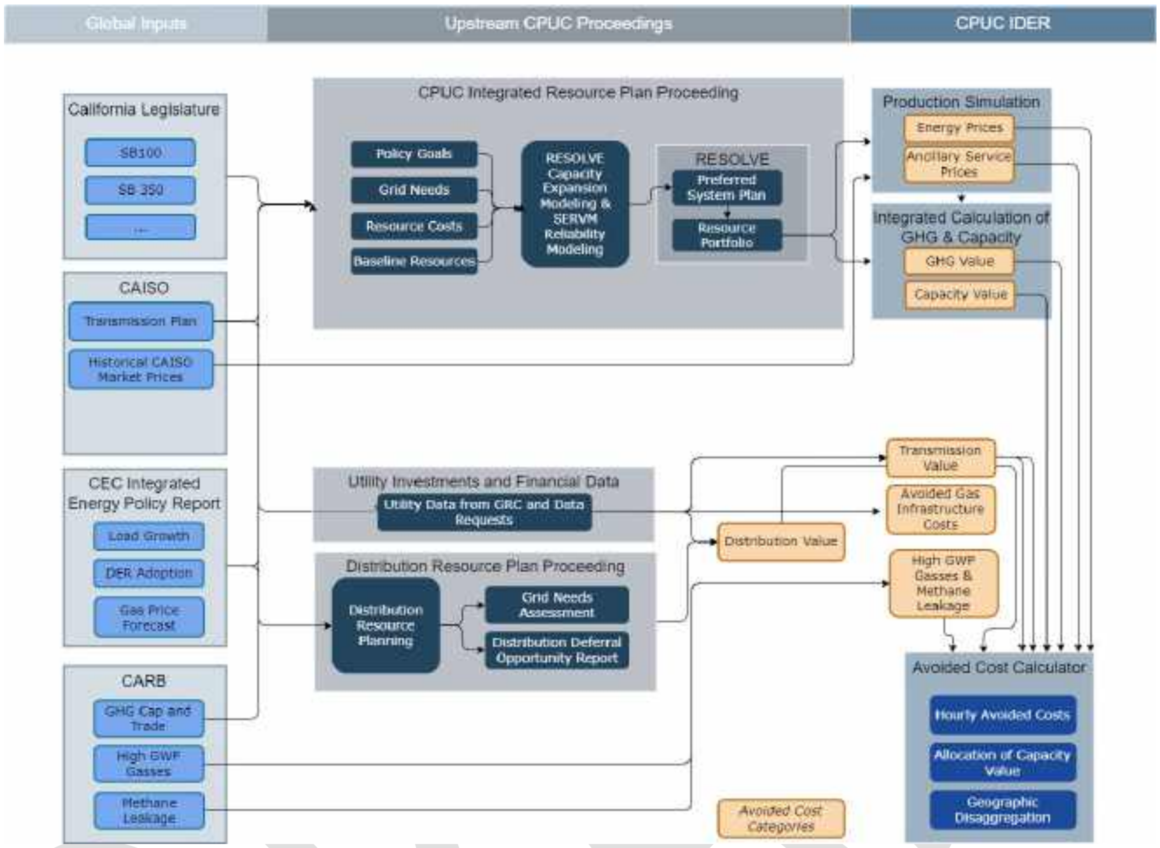
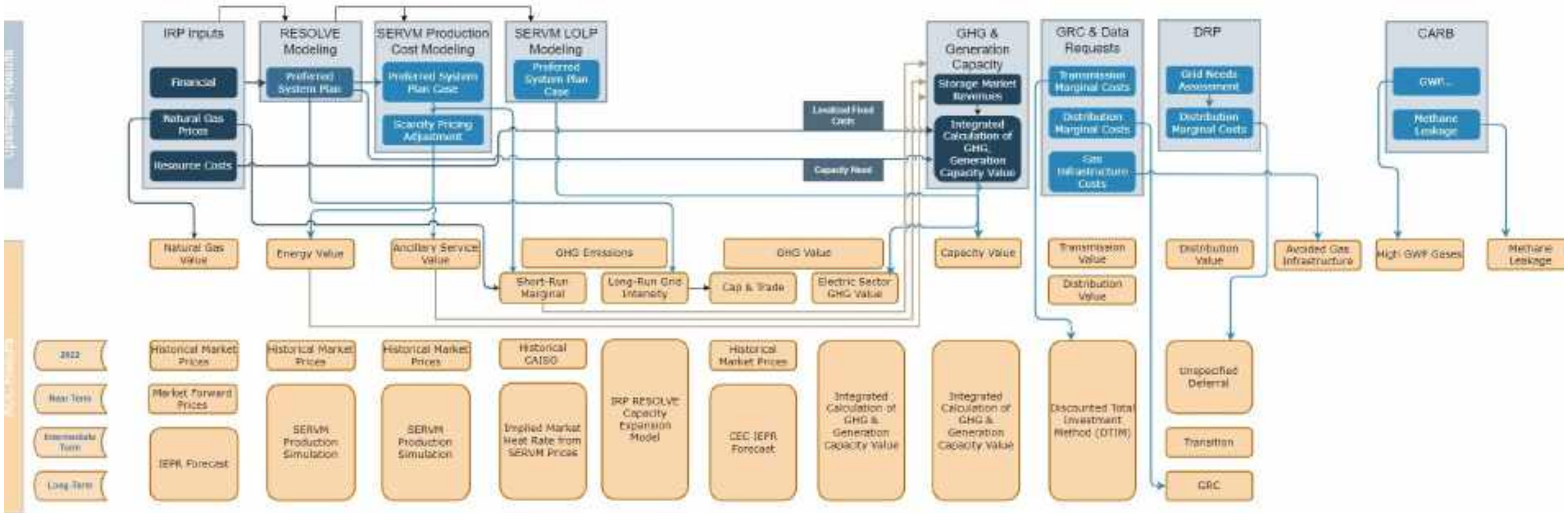


Figure 1-6. Avoided Cost Calculator Structure



1.3 Integrated Resource Planning Proceeding Inputs

Since 2020, the ACC has used inputs from the IRP proceeding.[6] By coordinating with IRP, the ACC better aligns with supply-side planning and projected future energy prices. This approach ensures greater consistency between demand-side resources evaluated using the ACC and supply-side resources evaluated in IRP.

1.3.1 IRP Planning Tools

California's IRP proceeding uses several planning tools to develop and support long-term resource plans that meet the state's reliability needs and decarbonization objectives. These models are useful sources of inputs to the ACC process.

The primary model used in the IRP proceeding is RESOLVE, a long-term capacity expansion model developed and maintained by E3 that has been made publicly available and subjected to stakeholder scrutiny. RESOLVE is a linear optimization model that co-optimizes investment and dispatch for a select number of days over a multi-year horizon to identify least-cost portfolios for meeting carbon emission reduction targets, renewables portfolio standard goals, reliability during peak demand events, and other system requirements.

The IRP proceeding also utilizes SERVM, a production simulation model, for a range of supporting analyses. These include loss-of-load-probability studies that provide key inputs to the IRP proceeding and detailed simulations of portfolios developed in RESOLVE to generate wholesale electricity prices, assess the reliability of the portfolio, and identify periods of risk. SERVM is developed and maintained by Astrapé Consulting.

1.3.2 2023 Preferred System Plan

New in the 2024 ACC is the use of the IRP's latest adopted system plan, the Preferred System Plan (PSP), rather than a counterfactual "No New DER" scenario used in previous versions of the ACC, including the 2022 ACC. The 2023 PSP, adopted by the CPUC in D.24-02-047, was developed using RESOLVE and is designed to meet the state's reliability needs and aggressive decarbonization objectives. The PSP represents a portfolio of resources that:

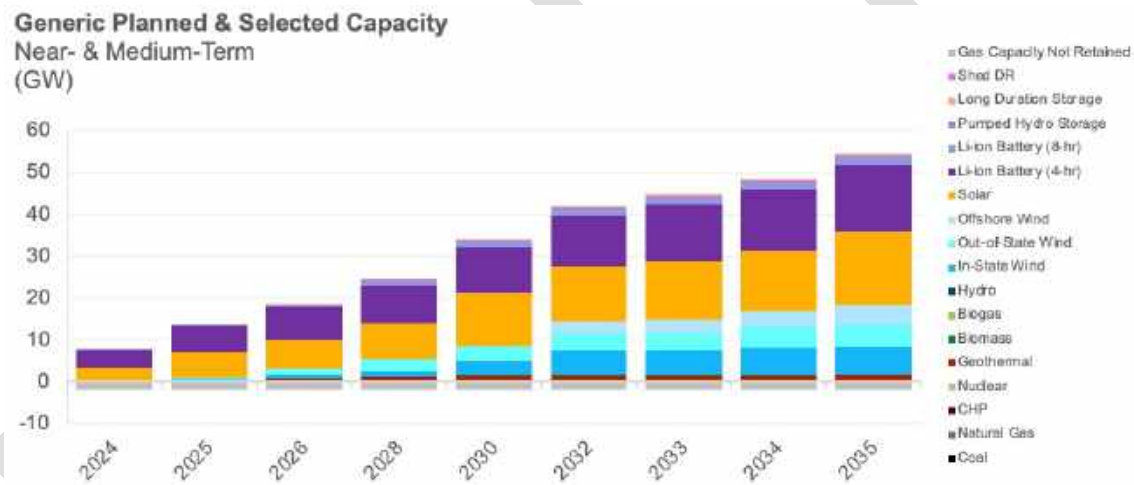
- Aligns with the load forecast and future DER adoption levels produced in the CEC's 2022 Integrated Energy Policy Report (IEPR).
- Meets statewide electric-sector GHG planning targets of 30 million metric tons by 2030 and 35 million metric tons by 2035, as well as state clean energy policy requirements established by SB100.
- Complies with the requirements of the Mid-Term Reliability (MTR) Procurement Orders (D.21-06-035 and D.23-02-040) – requiring a total of 15.5 GW of qualifying capacity from 2023 to 2028 – and meets a long-term planning reserve margin requirement throughout the planning horizon.

[6] See 2022-2023 IRP Events and Materials for source documents: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

- Includes resource additions identified by load-serving entities (LSEs) in plans they developed and submitted to the CPUC in the IRP proceeding pursuant to requirements established in D.22-02-004.
- Includes a diverse mix of new generation technologies to meet these requirements, including solar, onshore wind across a broad geographic footprint, offshore wind, geothermal, energy storage resources with a range of durations, and demand response.

Figure 1-7, reproduced from a public workshop hosted in the IRP proceeding, shows the nameplate capacity of new resources included in this portfolio, which exceed 50 GW by 2035. By 2045, the PSP includes nearly 120 GW of new nameplate capacity (not pictured here), primarily continued additions of solar, storage and wind.

Figure 1-7. PSP capacity additions through 2035[7]



1.3.3 Linkages Between IRP and ACC Proceedings

The PSP and associated inputs, assumptions, and results are used in multiple stages of the development of the ACC. Specifically:

- General inputs and assumptions used in the ACC are aligned with the IRP proceeding where possible. Examples include the utility Weighted Average Cost of Capital (WACC) and the natural gas price forecast (originally a product of the CEC's IEPR).
- The PSP portfolio produced by RESOLVE is simulated in SERVM, an hourly production simulation model. The results of these simulations are used directly in both the development of the avoided costs of energy (Section 3) and greenhouse gas emissions (Section 5.4) and in the allocation of generation capacity value to specific hours of the year (Section 5.5).
- A variety of outputs produced by both RESOLVE and SERVM – including the long-term cost of new solar and storage resources and their respective energy values, marginal capacity contributions,

[7] 2023 Proposed PSP & 2024-2025 TPP: Resolve Modeling Results with updated slides, slide 57, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/2023-proposed-psp-and-2024-2025-tpp-resolve-analysis-slide-deck_final-v2.pdf

and marginal greenhouse gas impacts over time – are used in the Integrated Calculation of GHG and Capacity Avoided Costs (Section 5), which explicitly ties the combined avoided costs of energy, generation capacity, and greenhouse gas emissions to the costs of the new resources needed to meet the state's reliability needs and decarbonization objectives.

1.4 Distribution Planning Proceeding Inputs

In June 2019, the Distribution Planning and IDER proceedings jointly issued an Amended Ruling "to determine how to estimate the value that results from using DER to defer transmission and distribution (T&D) infrastructure".[8] The Ruling includes an Energy Division White Paper entitled *Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values* (T&D Staff White Paper) to estimate avoided T&D costs based on the forecast data provided in the IOU Grids Needs Assessment (GNA) and Distribution Deferral Opportunities Reports (DDOR). Utility GNA and DDOR reports filed in August 2023 are used to calculate near-term distribution avoided costs in the 2024 ACC update.

As first implemented in the 2020 ACC update, the 2024 ACC continued to apply the T&D Staff White Paper methodology for calculating transmission and distribution values. This methodology calculates specified and unspecified costs for both transmission and distribution.

Specified distribution deferral values are costs associated with distribution capacity projects that are currently being undertaken by each utility. Specified distribution deferral values are already estimated through the Distribution Investment Deferral Framework and therefore do not require further modeling to estimate or incorporate their values into the ACC.

Unspecified distribution deferral values are costs that reflect the increased need for distribution capacity projects that are likely to occur in the future but are not specifically identified in current utility distribution planning. Unspecified distribution deferral values are calculated using a system-average approach and a counterfactual forecast to determine the impact of DERs on load. Distribution avoided costs are developed using information from the Distribution Deferral Opportunity Report and the Grid Needs Assessment, as filed in the distribution planning proceeding, supplemented with information acquired through data requests (Section 10).

2 Natural Gas Avoided Costs

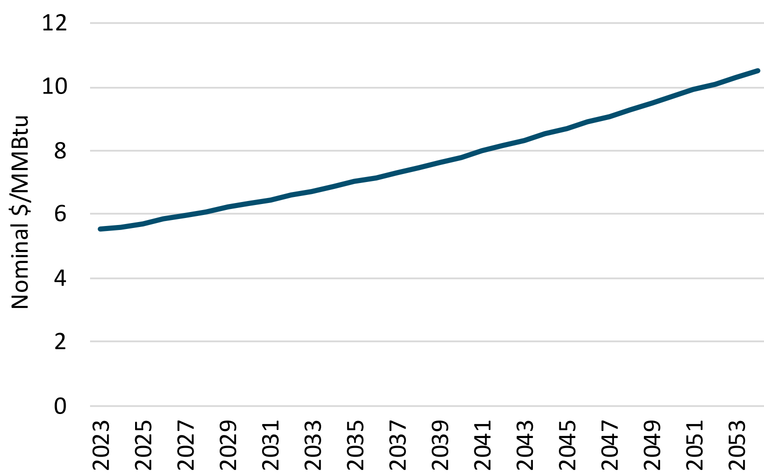
Natural Gas ACC is developed to determine the benefits of programs which reduce direct natural gas consumption. In the 2022 ACC, the Natural Gas ACC switched to CEC IEPR forecasts to develop avoided costs both for retail natural gas consumption and for electric generation, to be consistent with IRP. This is to ensure that demand-side resources and supply-side resources are evaluated using the same assumptions.

[8] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 13, 2019.

2.1 Continental Natural Gas Market

Natural gas delivered to California consumers is traded in an aggregate wholesale market that spans most of North America. Interstate natural gas pipelines transport the gas from the wellhead to wholesale market centers or "pricing hubs," where buyers include marketers, large retail customers, electric generators, and local distribution companies (LDCs) that purchase gas on behalf of small retail customers. The two pricing hubs most relevant for California are "PG&E Citygate" and "SoCal Border." The IEPR Power Plant Burner Tip Price Forecast provides monthly forecasts for the SoCal Border and PG&E Citygate up to 2059[9]. The ACC translates the annual forecast values into monthly values using multipliers derived from the IEPR forecast and extrapolates values beyond 2035 (Figure 2-1~~Figure 2-1~~). The EG natural gas avoided costs are then used as an input for the Electric ACC.

Figure 2-1. CA Gas Price Forecast ($Nominal)

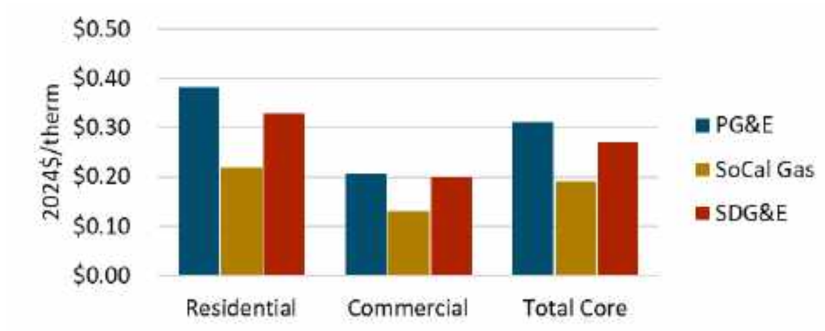


2.2 Avoidable Marginal Distribution Costs for Core Customers

Avoided distribution costs reflect avoided or deferred upgrades to the distribution systems of each of the three IOUs in California. Unlike with electricity, hourly allocations are not necessary because of the ability of utilities to "pack the pipe," making use of the natural storage capacity of gas pipelines. Costs are allocated to winter peak months, however, to reflect the winter-peak driven capacity costs, especially for distribution pipe serving core customers. "Core" customers refer to the residential and small commercial customers that represent the majority of natural gas utility customers in California. The avoided costs were updated for the 2024 ACC with values provided by the IOUs. 2024 values are show in Figure 2-2.

[9] Preliminary 2023 IEPR Electric Generation Price Model, available from the CEC's Natural Gas Electric Generation Prices for California and the Western United States website https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-electric-generation-prices-california-and

Figure 2-2. Natural Gas T&D Avoided Costs by Utility for 2024



2.3 Transportation Charges for Electric Generators

Avoided natural gas costs for electric generators serve as inputs to electricity avoided costs. Electric generators in California purchase natural gas directly from the wholesale market, paying transportation charges to Location Distribution Companies (LDCs). Because generators are not core customers, the appropriate measure of avoidable transportation charges is the applicable LDC tariff rate, which is reflected in the CEC IEPR Power Plant Burner Tip Price Model[10]. Thus, the CEC IEPR Power Plant Burner Tip Price Model is the source used for natural gas price forecast and transportation rates used in the electric model of the ACC. The 2024 ACC uses gas price forecasts directly from the IRP PSP inputs, to ensure alignment with the IRP proceeding. These gas price forecasts take the average transportation rates across several hubs from the CEC IEPR forecasts.

2.4 Natural Gas GHG Value

In 2022, the ACC adopted an 'interim' separate (and higher) GHG value for natural gas. This was intended to reflect that decarbonizing direct natural gas combustion in buildings through building electrification or use of renewable natural gas or other fuels is currently projected to be more expensive than avoiding GHG in electric generation. Assuming renewable natural gas supplies are likely to be targeted for otherwise hard-to-electrify applications, building electrification was found to be the best proxy for a marginal resource for decarbonizing natural gas, at least for this interim value.

[10] Preliminary 2023 IEPR Electric Generation Price Model, available from the CEC's Natural Gas Electric Generation Prices for California and the Western United States website https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-electric-generation-prices-california-and

In the 2022 ACC, the interim value was based on the $114/tonne GHG abatement cost for residential building electrification from the CEC report[11], escalated at utility WACC from 2020 to 2054.[12] The 2024 ACC retains the same gas GHG value as the 2022 ACC.

3 Avoided Cost of Energy

Since 2020, a production simulation model has been used to generate values for the energy, ancillary services, and emissions avoided cost components. California's electricity grid is rapidly evolving with the integration of renewable energy generation and energy storage, and wholesale electricity market price shapes depart from historical trends. Therefore, the Avoided Cost Calculator incorporates production simulation modeling for forecasted years. The CPUC performs extensive production simulation modeling as a part of the IRP modeling, providing a logical source of consistency between the IRP proceeding and the ACC. Day-ahead (DA) hourly energy prices from SERVM are used for the energy component of the ACC to evaluate all types of DER.[13] These hourly energy prices reflect the marginal costs of fuel and power plant operating costs in each hour.[14]

Since the 2020 ACC update, Astrapé has updated algorithms used in SERVM and the CPUC staff and Astrapé performed benchmarking of SERVM model results to calibrate outputs against actual CAISO prices, including – new to the 2024 ACC – an endogenous scarcity pricing function described below. CPUC staff performed new SERVM modeling with the PSP portfolio provided by IRP RESOLVE modeling with the updated SERVM model for the 2024 ACC update. A comparison of 2022 and 2024 SERVM model results is presented in Appendix 12.1.

The composite energy prices produced by SERVM reflect either scarcity conditions or typical marginal cost of production and were robustly calibrated to historical pricing. The role that energy constrained resources will have on market prices in the future is still uncertain, however. The scarcity energy prices in SERVM simulations on days in which storage resources are energy constrained currently only reflect the hourly load and resource balance. In reality, energy availability constraints will likely spread out scarcity pricing effects across a broader range of hours.[15] As an illustration, on a day with an extreme net load peak where loss of load is forecast, all storage resources would prefer to make their energy available for the tightest reserve

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

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

[13] Note that for electrification measures that increase electric load, this value is a cost, not an 'avoided' cost.

[14] The costs of greenhouse gas allowances required under CARB cap and trade are not explicitly included in SERVM and is therefore not reflected in the energy prices produced by the model. These costs are included in the ACC as a separate component and are calculated on an hour-by-hour basis based on the hourly marginal emissions factors described in Section 5.4 and an assumed projection of allowance costs consistent with assumptions used in the IRP proceeding.

[15] To be clear, the scheduling of conventional resources is designed to minimize total production costs, so the hourly marginal energy pricing is accurate, but what individual units can be expected to capture in the energy market will potentially be spread over more hours than their actual dispatch.

hour to maximize revenue. But if all resources behave in this manner, the scarcity will surface in other hours where at least some energy constrained resources are needed for dispatch. Theoretically, the scarcity market prices would be expected to spread out to all hours of storage dispatch to reflect this energy fungibility. Given these market behaviors have not been robustly observed, no changes for this effect have been implemented in the SERVM prices to date. This means that market prices projected by SERVM, particularly in later years with higher penetrations of energy limited resources, may overstate the opportunity for marginal storage resources to earn energy revenues. This effect will be revisited in future ACC cycles.

3.1 Scope of SERVM Simulations

Model runs are performed for years 2024-2035, 2040, and 2045 to reflect forecasted changes in system load and generation portfolio. In years where a resource portfolio is not available from RESOLVE modelling, resource additions are linearly interpolated from available RESOLVE years. Each year assumes the CEC's California Thermal Zone 2022 (CTZ22) typical meteorological year (TMY), shown in the table below.[16] As part of the IRP process, CPUC staff developed predictive models for system load shape and renewable generation profiles based on hourly weather conditions. To accurately model the effects of real weather data, CTZ22 selects specific full historical months, and references those historical months consistently across the state. For example, for the month of June, each climate zone will use local weather data from June 2013. Climate zone effects are then aggregated up to balancing authority and statewide levels.

Table 3-1. CTZ22 Historical Weather Months

CTZ Weather Year	
Month	Year
1	2004
2	2008
3	2014
4	2011
5	2017
6	2013
7	2011
8	2008
9	2006
10	2012
11	2005
12	2004

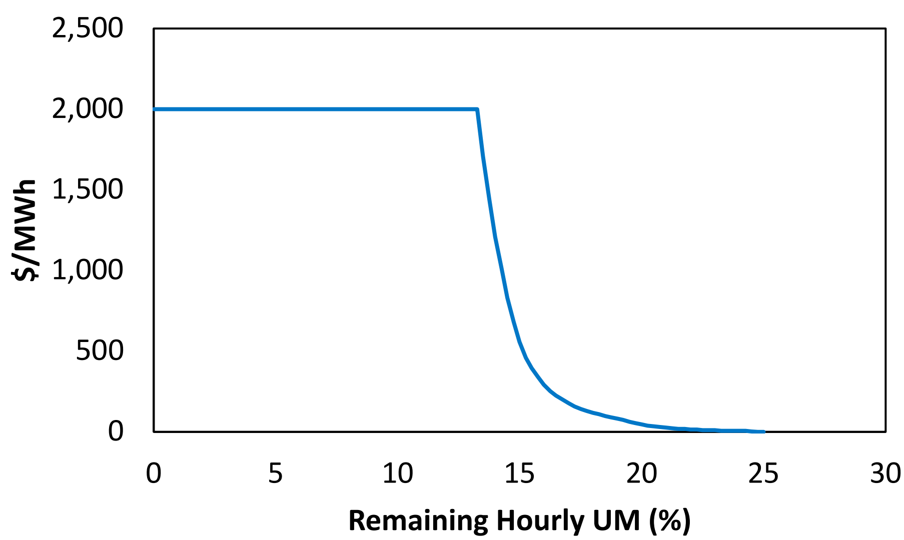
[16] See presentations from Oct 17, 2019 CEC Workshop and methodology reports under Dockets #19-BSTD-03 and #19-BSTD-04

To accurately model grid conditions, SERVM has representations of each balancing area in the Western Electricity Coordinating Council's jurisdiction. Since the ACC is focused on evaluating programs within IOU territories, SERVM outputs are taken from California IOU balancing areas – PG&E, SCE, and SDG&E. These results are aggregated up to NP-15 (PG&E) and SP-15 (SCE and SDG&E) by taking load-weighted averages of hourly market price forecasts.

3.1.1 Scarcity Pricing in SERVM

For the 2024 ACC, SERVM production simulation included scarcity pricing directly in energy price outputs, as opposed to being included as a post-processing step, as was done in the 2022 ACC. Scarcity pricing represents non-ideal market conditions prominent in the highest hours when the system is operating near full capacity. The scarcity pricing function in SERVM ties scarcity pricing adders to periods of low operating reserves and was calibrated using historical market price data.

The process to develop an endogenous scarcity adjustment in SERVM began with a generic exponentially decaying scarcity pricing function that was capped at the $2,000/MWh set by CAISO's Hard Energy Bid Cap. The x-axis of the scarcity pricing function is the total reserves available including demand response and other emergency resources. This curve was shifted right until the modeled and historical scarcity were in alignment. The final modeled ORDC is presented in the Figure below.



3.2 Adjustments to SERVM Prices

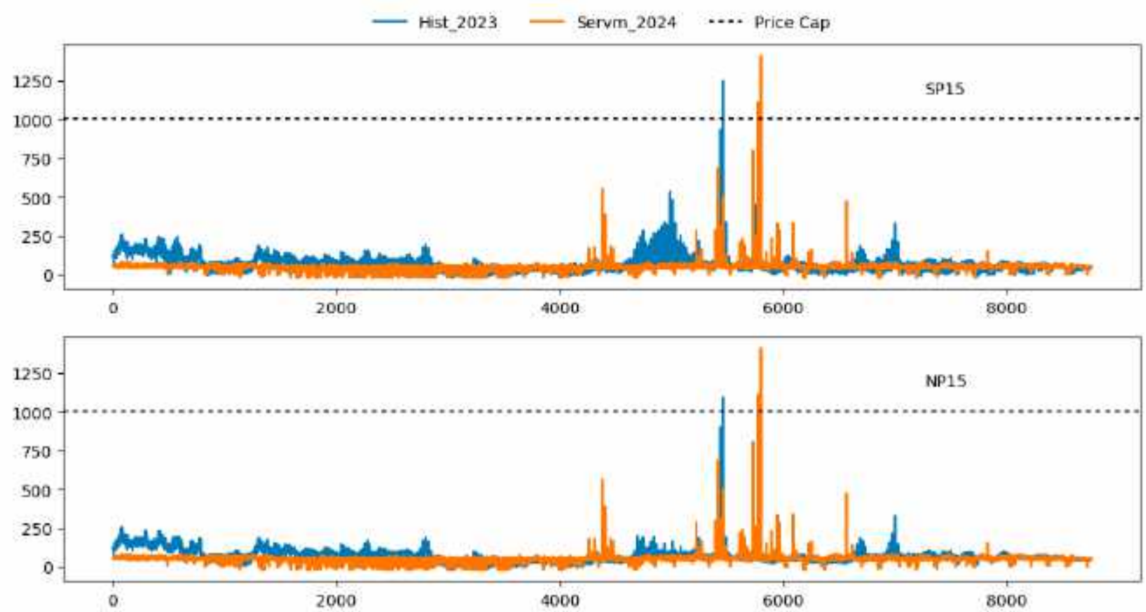
In the 2024 ACC, two post-processing adjustments are applied to the hourly energy prices produced by SERVM:

(1) A price floor of zero is applied such that there are no negative energy prices in the avoided costs. Negative pricing observed in wholesale markets today is largely reflective of the opportunity cost associated with curtailment of renewable resources and the corresponding loss of the renewable energy credit that can be used to comply with the state's RPS requirements. The ACC values resources (including renewables) based on their greenhouse gas reduction value (rather than their

RPS compliance value), meaning that the value of the clean attribute they provide is reflected in the GHG avoided cost.

(2) A price cap of $1000/MWh is also applied based on the soft cap of $1000/MWh in the CAISO markets and the observation that historical prices in 2023 rarely exceeded this value. Figure 3-1~~Figure 3-1~~ shows the historical prices in 2023 and raw SERVM prices in 2024.

Figure 3-1. Comparing Historical and SERVM Simulated Energy Prices, Showing Price Cap



3.3 Implied Marginal Heat Rates

Hourly energy price outputs from SERVM are used to derive hourly implied market heat rates (IMHR) for each hour simulated. IMHR is a simple but useful indicator of the marginal resource that determines the value of energy in each hour. It is independent of the impact of evolving gas and carbon prices, which makes it a suitable reference for interpolating and extrapolating future energy prices.

The derivation of IMHR values as an intermediate step serves several purposes in the ACC framework, each described in further detail in subsequent sections. First, they are used in the process of interpolating and extrapolating avoided costs to years for which explicit simulations were not conducted (described further below). Second, they are used to derive implied marginal emissions factors (tonnes/MWh) for each hour, which both serve as intermediate inputs into the Integrated Calculation of GHG and Capacity avoided costs and are used, in conjunction with the resulting GHG avoided cost ($/tonne) to determine the final hourly GHG avoided cost.

The IMHR in each hour is calculated as:

$$IMHR_i = \frac{P_{e,i} - VOM_{CC}}{P_g}$$

Where $P_{e,i}$ is the energy price in hour *i* in \$/MWh, VOM_{CT} is the variable operations and maintenance (O&M) cost of a combined cycle generator in \$/MWh, P_g is the gas price in \$/MMBtu.

3.4 Marginal Emissions Factors

The IMHR can be translated directly to a marginal emissions factor that represents the quantity of greenhouse gas emissions avoided by a 1 MW reduction in load (or by 1 MW of additional generation) in each hour. While the marginal emissions factors do not directly impact the energy component of avoided costs, they are used in the process of determining both the annual and hourly GHG avoided costs (described in Section 5).

The conversion of IMHR to a marginal emissions factor is based on the carbon content of natural gas fuel (117 lb./MMBtu, or 0.053 metric tons per MMBtu). For instance, in an hour in which the IMHR is 7,000 Btu/kWh (a typical heat rate for a combined cycle natural gas plant), the marginal emissions factor would be 0.371 metric tons per MWh.

In the application of marginal emissions factors to determine GHG avoided costs, an upper bound corresponding to an IMHR of 12,500 Btu/kWh (0.663 metric tons per MWh) is applied. This is consistent with upper limits assumed in previous ACCs and is intended to reflect the fact that few natural gas units operational today have physical heat rates above this level.

3.5 Interpolation & Extrapolation

The scope of the ACC extends to 2054, while the SERVM model provides results in years 2024-2035, 2040 and 2045. Energy prices within intervening periods and beyond 2045 are interpolated and extrapolated, respectively, based on hourly IMHR values. Within the periods 2035-'40 and 2040-'45, the IMHR in each hour of the year is linearly interpolated. Beyond 2045, the IMHR is assumed to remain constant.

To determine the hourly avoided energy cost, the IMHR values are used in combination with the natural gas price forecast to calculate hourly energy prices in years for which SERVM simulations are not conducted:

$$P_{e,i} = IMHR_i \times P_g + VOM_{CC}$$

Fuel costs for final calculation of electricity generation prices are consistent with natural gas commodity prices discussed in Section 2.

3.6 Summary of Results

The final energy avoided costs follow the expected trend of the effects of increased renewable generation and curtailment in the spring. Periods of high renewable production and low load in the spring show very low prices. In near-term years, peak prices occur in the summer evenings. In later years, peak prices continue to occur in summer system peak hours, but also occur in evenings and mornings of months that have limited renewable generation availability and greater electrification demands. As electric space and water heating begin to develop and EV charging will occur overnight, those hours will increasingly be supplied with additional imports or dispatchable energy, which will lead to increasing prices in the overnight hours. Pricing patterns seen in upcoming years will follow changes to the overall electric portfolio, presenting differing price signals depending on how new resources fit into the overall mix. The day-ahead energy prices from SERVM for SP-15 are shown below in Figure 3-2 to Figure 3-4.

Figure 3-2. 2024 SP-15 Day Ahead Market Prices from SERVM

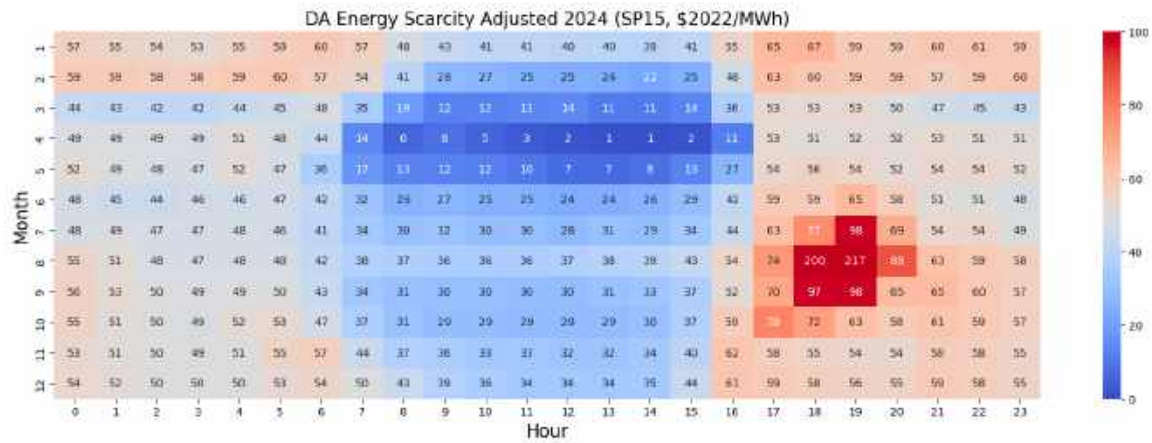


Figure 3-3. 2030 SP-15 Day Ahead Market Prices from SERVM

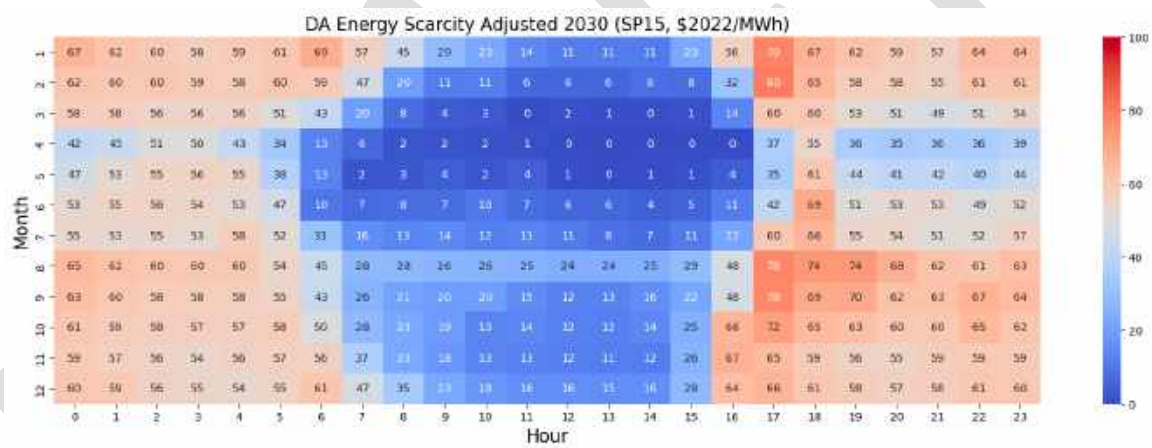
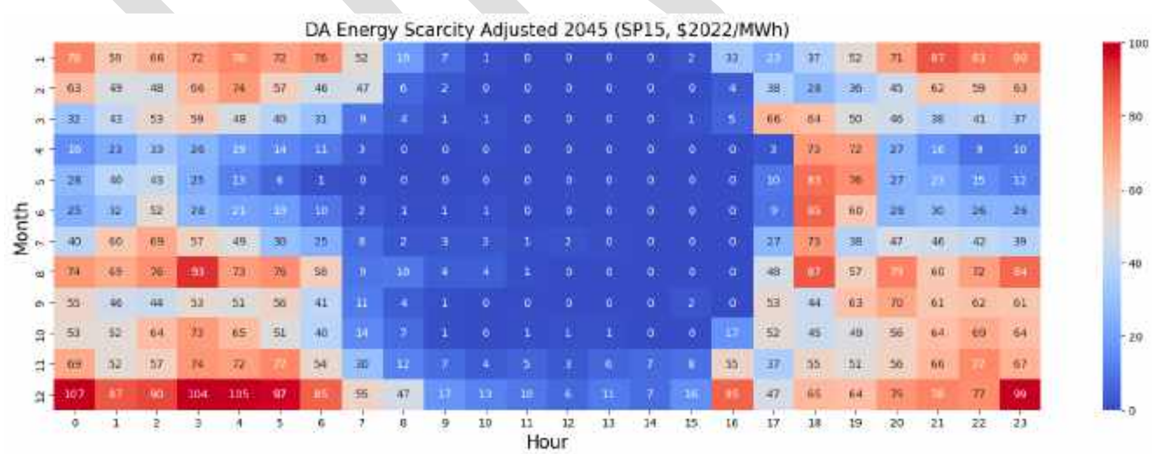


Figure 3-4. 2045 SP-15 Day Ahead Market Prices from SERVM



4 Ancillary Services

The CAISO procures ancillary services (AS) to maintain the reliability of the grid and competitiveness of energy markets. Common AS products include regulation reserves, spinning reserves and non-spinning reserves. Regulation reserves are provided by generation resources that are running and synchronized with the grid and able to increase (reg up) or decrease (reg down) their output instantly. Spinning reserves are provided by generation resources that are running and capable of ramping up within 10 minutes and running for at least two hours. Non-spinning reserves are provided by resources that are available but not running.

Ancillary services and their costs factor into the ACC in two places:

- Within the Electric Sector Model, an avoided ancillary services cost is included for each hour. This cost represents the potential savings resulting from a load reduction since the procurement of some ancillary services (i.e., spinning and non-spinning reserves) is directly linked to the level of load.
- Additionally, ancillary services prices impact the Integrated Calculation. Hourly AS prices are used to calculate storage revenues as inputs to the Integrated Calculation in deriving generation capacity and GHG avoided costs (see section 5.2.2. for details)

4.1 Ancillary Services Prices

For 2024 ACC, SERVM outputs hourly prices for three AS products: regulation down, regulation up and spinning services. This is different from the 2022 ACC where SERVM only generated combined regulation and spin prices, with regulation prices split between regulation up and down using historical data.

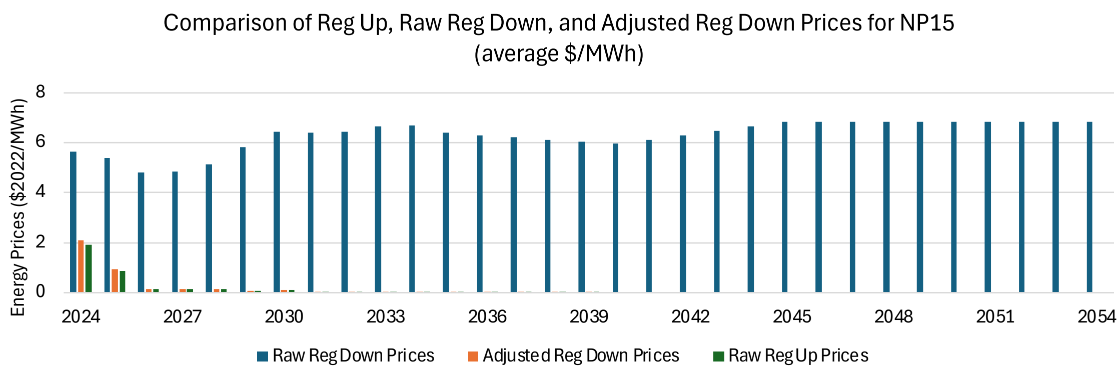
4.1.1 Adjusting Regulation Down Pricing

The price stream generated by SERVM for regulation down is significantly higher than all other AS products and does not decrease in the long term. This trend contradicts the expectation that increased grid storage would lower the opportunity costs for AS products, thereby exerting downward pressure on AS prices. While prices for regulation up and spinning reserves from SERVM indicate an "AS saturation" effect, regulation down prices do not reflect this trend. To address this discrepancy and better align regulation down prices with observed market dynamics, adjustments were made based on the historical correlation between regulation up and down prices. The adjustment formula is as follows:

$$P_{Adjusted,Reg\ Down,i} = P_{Raw,Reg\ Down,i} * \frac{\sum_i P_{Raw,RegUp,i}}{\sum_i P_{Raw,RegDown,i}} * Hist_{RegDown/Up}$$

Here, P represents Reg up or Reg down Prices in hour i in \$2022/MWh. $Hist_{RegDown/Up}$ is the historical correlation between reg up and reg down prices. It is the ratio between the sum of historical reg down and reg up prices over the years 2019-2023. This recalibration ensures that reg down prices saturate at the same pace as reg up prices, without altering their daily shapes.

Figure 4-1. Difference of magnitude between raw reg up and reg down prices



4.2 Avoided Ancillary Services Costs

In ACC, avoided ancillary service costs represent ancillary procurement that could be avoided by load reduction. Reducing load generally decreases the amount of spin and non-spin AS that must be procured to operate the CAISO system. Regulation services are not part of the avoided ancillary service costs because its procurement doesn't depend on load, but rather observed needs during the same periods in prior year and in the previous month.

In 2022, total ancillary services costs were 1.1% of total wholesale energy costs latest CAISO Annual Report on Market Issues and Performance.[17] Consistent with the 2022 ACC, the 2024 ACC assumes that half of these costs (0.55% of wholesale energy costs) are associated with ancillary services that scale directly with load (and therefore could be avoided by incremental DER resources). For each future year, the ancillary services costs as a percentage of wholesale energy costs are adjusted by the ratio of projected spinning reserves prices to wholesale energy prices. For example, in 2022, the average price of spinning reserves was roughly 11% of the average wholesale energy price. In 2024, the simulated spinning reserve price in SERVM is roughly 4% of the average wholesale energy price in SERVM. Therefore, the avoided ancillary services costs for 2024 are calculated 0.2% (by multiplying 0.55% by the ratio between 4% and 11%).

5 Integrated Calculation of GHG and Capacity Avoided Costs

In the 2022 ACC, the avoided costs of generation capacity and greenhouse gas emissions were determined independently:

- The avoided cost of generation capacity, representing the incremental costs of procuring one megawatt of additional accredited capacity, was determined by calculating the "missing money"

[17] CAISO, 2022 Annual Report on Market Issues and Performance, July 2023, Available at: https://www.caiso.com/documents/2022-annual-report-on-market-issues-and-performance-jul-11-2023.pdf

of a marginal capacity resource (energy storage) in each year using a real economic carrying charge (RECC) approach.

- The avoided cost of greenhouse gas emissions ("GHG avoided cost"), intended to reflect the incremental costs of supply-side resources needed to reduce emissions by one metric ton, was tied to the "shadow price" of the 2035 greenhouse gas planning target constraint in RESOLVE.

The 2024 ACC combines the determination of generation capacity and GHG avoided costs into a single step, the Integrated Calculation of Generation Capacity and GHG Avoided Costs ("Integrated Calculation"). The rationale for this improvement is that these two avoided costs are inherently interdependent, as the portfolio of resources that will satisfy both the state's reliability needs and decarbonization objectives includes many resources that provide both capacity and greenhouse gas value to the system. For example:

- Solar resources reduce greenhouse gas emissions by displacing natural gas generation during the day, but also provide generation capacity value during the late afternoon and evening hours.
- Energy storage resources can be dispatched during periods of scarcity to provide generation capacity value, but also support the greenhouse gas objectives of the state by charging and discharging during periods of lower and higher marginal emissions rates, respectively.

The premise behind the Integrated Calculation approach used in the 2024 ACC is that, together, the avoided costs of energy, generation capacity, and greenhouse gas emissions should align with the costs to invest in and operate the portfolio of resources needed to meet the state's reliability and decarbonization objectives. In this respect, the avoided costs of generation capacity and greenhouse gas emissions each represent implicit price signals that should be sufficient to support the long-term investments in new resources necessary to meet those dual objectives.

Solving for both avoided cost components simultaneously requires a more sophisticated modeling approach than used in previous cycles of the ACC. The Integrated Calculation uses optimization – described in further detail below – to solve for these two variables across the entire planning horizon by ensuring that the values for each are sufficient to sustain investments across the planning horizon in two representative resources: solar and energy storage.

While the mechanics of this calculation are unique, the overall principles behind this approach are consistent with both other planning processes and previous cycles of the ACC:

- In the IRP proceeding, the CPUC relies on RESOLVE, an optimization-based capacity expansion model, to identify the Preferred System Plan. Within this optimization, the least cost portfolio of resources is determined by balancing the cost of each potential resource option with its energy value, its contribution to the planning reserve margin, and its effect upon greenhouse gas emissions. The three value streams that principally impact resource valuation in RESOLVE align closely with the components of the ACC.
- In the 2022 ACC process, one of the consequences of adopting the RECC approach to calculate capacity value produced avoided generation capacity costs that, when combined with the energy values provided by storage resources, closely matched the net present value cost assumed for new energy storage resources. The Integrated Calculation is designed to produce similar outcomes by

including constraints that the combined energy, capacity, and greenhouse gas values attributed to representative resources must meet their net present value costs.

5.1 Model Formulation

The Integrated Calculation solves simultaneously for the generation capacity and GHG avoided costs across the 30-year time horizon of the avoided costs, seeking to identify the values that are sufficient to allow each representative resource to fully recover its costs while minimizing costs to ratepayers. Table 5-1 describes the two countervailing forces that shape the avoided costs: under equilibrium conditions, the avoided costs for energy, generation capacity, and greenhouse gas emissions should be closely aligned with the total costs of new supply-side resources.

Table 5-1. Two countervailing forces captured in formulation of the Integrated Calculation

IRP Portfolio Dynamics	**Energy, capacity, and greenhouse gas values must be sufficient to support investments in resources identified as a least-cost portfolio to meet future reliability & clean energy goals**	**In a least-cost portfolio, resources are added to the portfolio until the point at which their marginal value declines to match their marginal cost**
Integrated Calculation Formulation	Constraints applied to each representative resource for each vintage to ensure net present value is at least as large as net present value cost	Optimization problem formulated as a cost minimization to determine lowest possible combination of capacity & GHG avoided costs that satisfy constraints

In practice, the balance between these two forces in the Integrated Calculation is determined by using constrained optimization to solve for a cost-minimizing combination of generation capacity and GHG avoided costs while ensuring that the resulting values are sufficient to offset the net present value costs of representative resources. The revenue neutrality constraint is applied to multiple representative resources on a net present value basis for each vintage and can be expressed as:

$$C \leq R_{energy} + R_{AS} + \boldsymbol{AC_{GC}} \times Q_{ELCC} + \boldsymbol{AC_{GHG}} \times Q_{GHG}$$

Table 5-2 defines each variable, its respective units, and the data source. The top two rows are decision variables; shaded rows are parameters for the optimization equation.

Table 5-2. Decision variable & parameter descriptions for updated GHG and generation capacity avoided cost calculation.

Decision Variable or Parameter	Description	Units	Source
AC_{GC}	Generation Capacity Avoided Costs	$/kW-year	To be Calculated
AC_{GHG}	GHG Avoided Costs	$/tonne	To be Calculated
Q_{ELCC}	Deemed RA contribution	ELCC kW	RESOLVE output

Q_{GHG}	Marginal GHG impacts	tonne/kW-yr.	Derived via SERVM energy prices
C	Resource Cost (Levelized Fixed Costs + Operations and Maintenance (O&M))	$/kW-yr.	RESOLVE output
R_{energy}	Net Energy Revenues (excluding cap-and-trade prices)	$/kW-yr.	Derived via SERVM energy prices
R_{AS}	AS Revenues	$/kW-yr.	Derived via SERVM AS prices

Each component in the equation above represents a net present value across the assumed lifetime of the resource; the equation below provides the expanded version of the same equation (where d is the discount rate, i is the first year of the resource, and n is the lifetime of the resource):

$$
\begin{aligned}
&NPV(d, \{C_i, C_i, \dots, C_i\}) \\
&\qquad \le NPV\left(d, \{R_{energy,i}, R_{energy,i+1}, \dots, R_{energy,i+n}\}\right) + NPV\left(d, \{R_{AS,i}, R_{AS,i+1}, \dots, R_{AS,i+n}\}\right) \\
&\qquad + NPV\left(d, \{\boldsymbol{AC_{GC,i}} \times Q_{ELCC,i}, \boldsymbol{AC_{GC,i+1}} \times Q_{ELCC,i+1}, \dots, \boldsymbol{AC_{GC,i+n}} \times Q_{ELCC,i+n}\}\right) \\
&\qquad + NPV\left(d, \{\boldsymbol{AC_{GHG,i}} \times Q_{GHG,i}, \boldsymbol{AC_{GHG,i+1}} \times Q_{GHG,i+1}, \dots, \boldsymbol{AC_{GHG,i+n}} \times Q_{GHG,i+n}\}\right)
\end{aligned}
$$

The optimization aims to calculate **Generation Capacity Avoided Costs ($\boldsymbol{AC_{GC}}$)** and **GHG Avoided Costs ($\boldsymbol{AC_{GHG}}$)** every year based on other parameters listed in the table; the optimization minimizes total costs of representative resources subject to the condition that each resource selected in the portfolio must be made whole of its resource cost.

In addition to calculating avoided costs that minimize the total cost, the following constraints and features are applied to ensure resulting avoided costs are within appropriate range and do not fluctuate excessively year by year:

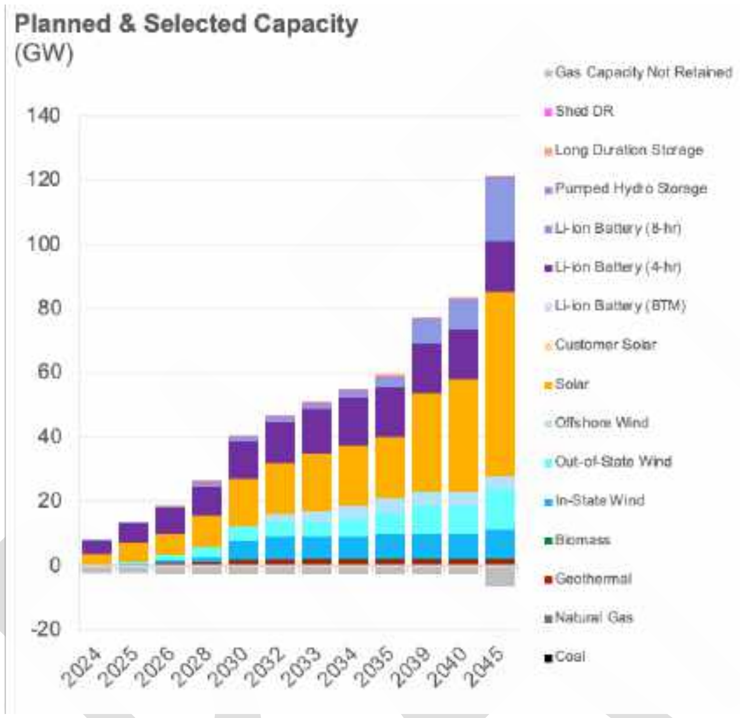
- Avoided costs should cover at least the first year of resource levelized costs minus energy and AS revenues.
- The Integrated Calculation solves for GHG and Capacity avoided costs in years with explicit SERVM prices. For 2024 ACC, the years are 2024-2035, 2040 and 2045. Avoided costs for intervening years are interpolated linearly, consistent with the calculation of energy avoided costs in years without SERVM prices. After 2045, generation capacity and GHG avoided costs are escalated at a nominal inflation rate.

5.2 Key Assumptions

5.2.1 Preferred System Plan Resource Additions

The method described above is applied to develop avoided costs consistent with the CPUC's Preferred System Plan developed in the IRP proceeding. This portfolio includes resources sufficient to meet the state's near- and long-term reliability needs and meets a greenhouse gas planning target of 25 MMT in 2035. The cumulative new resource additions needed to meet these objectives is shown below.

Figure 5-1. CPUC IRP Preferred System Plan (PSP) new capacity additions



Based on these results, the Integrated Calculation includes two types of resources to derive avoided costs: generic utility-scale solar and lithium-ion battery storage.[18] These two resources are suitable choices for this exercise for multiple reasons:

- Both resources are selected economically throughout the IRP planning horizon (2024-2045), reflecting their respective long-term roles as scalable resources to meet the state's reliability and decarbonization goals.
- The two resources are sufficiently different from one another in the combination of values that they provide the system that they allow for meaningful differentiation of capacity and greenhouse gas value.
- When compared with other renewable resources, solar resources are relatively homogeneous in quality, making the definition of a "generic" solar resource for inclusion in this exercise more straightforward (in contrast, wind capacity factors and profiles vary considerably across geographies).

[18] Mirroring the resource selection observed in the PSP developed in RESOLVE, the duration of energy storage resources included in the Integrated Calculation modeling is assumed to transition from four to eight hours in 2035.

While the PSP includes other new resources in addition to solar and storage, including all resources selected in the portfolio is not necessary to determine the value of capacity and greenhouse gas emissions. Within the context of a long-term optimization like RESOLVE, the same implicit values for reliability and greenhouse gas emissions are ascribed to different resources (accounting for each resource's ability to contribute to that need). In practice, this means that the greenhouse gas value determined for solar should be identical to the greenhouse gas value provided by all other resources that contribute to meeting the greenhouse gas planning target.

5.2.2 Representative Resource Characterizations

One of the overarching objectives of the Integrated Calculation is to harmonize assumptions with the CPUC's IRP proceeding (RESOLVE and SERVM). All inputs for the Integrated Calculation are either direct outputs from the two models or derived using RESOLVE and SERVM results. The section below describes the calculation of key inputs, which are shown in subsequent tables:

Levelized Fixed Costs: The levelized fixed costs as inputs to the Integrated Calculation are consistent with the IRP. In the IRP, the costs of new resources are represented as a real levelized cost, intended to represent a stream of payments from a utility to a third-party developer under a long-term power purchase agreement escalating with inflation. The same methods and assumptions – including assumptions on the cost parameters for the resource, how it is financed, and how those costs are incurred by a utility – are used in the 2024 ACC. The levelized cost of resources in a specific year is calculated based on cost assumptions (capital cost, fixed operations and maintenance costs, warranty and augmentation costs) and financing parameters (costs of debt and equity, financing life, debt term, and debt-to-equity ratio).

Since the 2022 ACC, costs for new solar and storage resources have risen. In the IRP, these higher costs are assumed to remain relatively stable in the near term before declining in the late 2020s and early 2030s. In the long term, as the pace of technological improvement slows, the so does the pace of cost declines. The declining cost trends for both solar and storage have an important impact on the Integrated Calculation, which accounts for the temporal opportunity cost of building a resource at a higher cost in one year rather than a lower cost the next.

Transmission Upgrade Costs due to Generation Addition: In the IRP, resource additions may require a transmission upgrade based on transmission capability and costs data provided by CAISO.[19] Transmission upgrade costs associated each resource are incorporated in resource levelized fixed costs. The costs are calculated as the following:

1. Using the selected resource and transmission builds from the RESOLVE Results Viewer for the 2023 PSP Core portfolio, marginal resource builds in each year are calculated for all resources.
2. The marginal transmission builds are multiplied by the levelized transmission upgrade costs ($/kW-yr.) to produce the marginal transmission costs in each year, in units of levelized 2022 $/yr.

[19] Inputs and Assumptions of 2022 IRP, Transmission Constraint Implementation, slides 83-86 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/iamag09222022.pdf

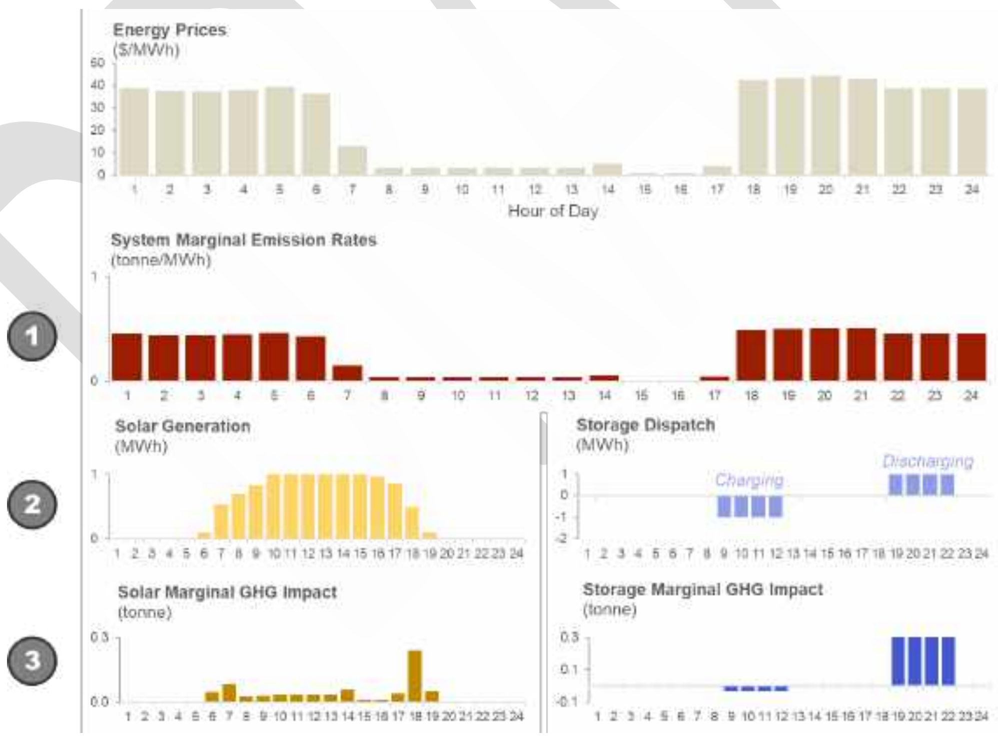
3. Marginal transmission costs are assigned to each resource, using the marginal resource builds and HSN constraint utilization factors ("Deliverability Factors") to determine the cost apportioning.

Energy Value (or Energy Revenues) [20]: energy revenues are calculated for each representative resource in each year by multiplying an hourly dispatch profile by the hourly energy price in that year. The solar generation profile is derived from SERVM resource availability profile, while the storage dispatch profile reflects the optimal dispatch of storage resources against SERVM energy prices and ancillary services prices.

Over the planning period, the energy value of solar resources declines. This reflects the effect of increasing saturation of renewable generation in day-time hours, which leads to increasingly frequent suppression of energy prices to zero. Meanwhile, energy revenues earned by the marginal storage resource increase over the same period, as the increasing frequency of low daytime prices presents an arbitrage opportunity for additional energy storage resources.

Marginal GHG Impact (tons/kW-yr.): The marginal GHG impact for each representative resource is the product of hourly marginal emissions factors and the resource's hourly dispatch profile. This value represents the quantity of greenhouse gas emissions displaced by each unit of generating capacity in each year. When multiplied by the GHG avoided cost ($/tonne), the result is the total annual GHG value provided by the representative resource. This approach is shown illustratively in the figure below.

Figure 5-2. Illustrative calculations of the GHG impacts of solar and storage on an example day



[20] This value does not include the value associated with avoided cap-and-trade allowances, which are included in the GHG avoided cost instead

Resource RA contribution: each resource's contribution to the system's capacity (or reliability) needs is characterized by its marginal ELCC, a direct output of RESOLVE in the CPUC IRP proceeding. Marginal ELCCs for solar resources are relatively low (<10%) today due to the timing of the net peak in the early evening and remain at similar levels through the planning period. Marginal ELCCs for energy storage are relatively high today but decline as the penetration of storage in the portfolio increases. The eventual shift from four- to eight-hour storage in RESOLVE is partially driven by the implicit need for longer duration storage that is reflected by the declining marginal ELCC.

The inputs to the Integrated Calculation Model are summarized as green cells in the following tables. All resources see cost declines as they are built in future years. While solar energy revenues and GHG contribution decline with higher penetration, storage revenues and GHG impacts increase overtime.

Generic Solar

Vintage/ Year	Fixed Costs by Vintage	Transmission Adder	Total Resource Fixed Costs by Vintage	Total Generation	Energy Revenues	Energy Value	Marginal GHG Impact	ELCC
	2022$/kW-yr	2022$/kW-yr	2022$/kW-yr	MWh/kW-yr	2022$/kW-yr	2022$/MWh	tonnes/MW-yr	%
2024	85.0	0.0	85.0	2.9	85.3	29.3	693.3	8%
2025	85.2	0.0	85.2	2.9	82.1	28.0	664.4	8%
2026	85.1	0.0	85.1	2.9	80.1	27.3	645.4	12%
2027	84.9	0.0	84.9	2.9	75.6	25.8	605.3	14%
2028	83.6	0.0	83.6	2.9	66.9	22.8	530.2	13%
2029	81.5	0.0	81.5	2.9	53.1	18.1	417.6	11%
2030	79.1	0.0	79.1	2.9	43.4	14.7	337.7	10%
2031	76.3	0.0	76.3	3.0	41.2	14.0	317.9	10%
2032	73.5	0.0	73.5	3.0	38.7	13.1	296.7	10%
2033	70.7	0.0	70.7	3.0	36.5	12.3	277.6	10%
2034	67.9	0.0	67.9	3.0	36.6	12.3	276.1	10%
2035	65.2	0.0	65.2	3.0	41.3	13.9	309.7	9%
2036	62.3	0.0	62.3	3.0	38.7	13.0	286.7	9%
2037	59.7	0.0	59.7	3.0	35.8	12.0	262.7	8%
2038	57.4	0.0	57.4	3.0	32.9	11.1	238.0	8%
2039	55.3	0.0	55.3	3.0	29.9	10.0	212.8	7%
2040	53.5	0.0	53.5	3.0	26.1	8.8	187.0	6%
2041	51.9	0.1	52.0	3.0	24.0	8.1	169.4	6%
2042	50.5	0.3	50.7	3.0	21.8	7.4	151.3	8%
2043	48.9	0.4	49.3	3.0	19.6	6.6	133.3	10%
2044	48.1	0.5	48.6	3.0	17.4	5.9	115.2	12%
2045	47.3	0.7	47.9	2.9	14.8	5.0	97.0	14%

Generic 4-Hour Storage

Vintage/ Year	Fixed Costs by Vintage	Transmission Adder	Total Resource Fixed Costs by Vintage	Total Generation	Energy Revenues	AS Revenues	Energy + AS Revenues	Energy Value	Marginal GHG Impact	ELCC
	2022$/kW-yr	2022$/kW-yr	2022$/kW-yr	MWh/kW-yr	2022$/kW-yr	2022$/kW-yr	2022$/kW-yr	2022$/MWh	tonnes/MW-yr	%
2024	169.9	0.0	169.9	1.4	38.6	35.7	70.6	51.6	334.5	79%
2025	169.9	0.0	169.9	1.4	50.5	14.1	61.4	43.4	406.4	79%
2026	171.6	0.0	171.6	1.4	54.9	1.2	53.4	37.4	427.5	66%
2027	170.8	0.0	170.8	1.4	59.4	1.3	57.6	40.2	458.8	52%
2028	167.1	0.0	167.1	1.4	65.6	1.5	63.7	44.3	504.5	48%
2029	157.0	0.0	157.0	1.4	75.5	0.7	72.4	50.1	576.6	45%
2030	147.4	0.0	147.4	1.4	81.9	1.2	78.9	54.5	618.4	42%
2031	138.8	0.0	138.8	1.4	84.7	0.4	80.9	55.8	633.2	42%
2032	134.8	0.0	134.8	1.5	87.0	0.3	83.0	57.2	644.2	42%
2033	130.7	0.0	130.7	1.5	92.1	0.2	87.6	60.2	671.1	42%
2034	126.7	0.0	126.7	1.5	93.9	0.1	89.3	61.3	678.1	42%
2035	123.4	0.0	123.4	1.5	92.0	0.0	87.4	60.1	659.4	40%
2036	121.0	0.0	121.0	1.5	92.6	0.0	88.0	60.5	661.9	38%
2037	119.3	0.0	119.3	1.5	96.3	0.0	91.5	62.8	679.6	36%
2038	117.7	0.0	117.7	1.5	102.0	0.0	96.9	66.5	708.4	34%
2039	116.1	0.0	116.1	1.5	109.1	0.0	103.6	71.2	742.1	32%
2040	114.5	0.0	114.5	1.5	117.5	0.0	111.6	76.8	775.8	30%
2041	112.8	0.0	112.8	1.5	117.3	0.0	111.4	76.5	752.1	28%
2042	111.2	0.0	111.2	1.5	120.0	0.0	114.0	78.2	739.4	24%
2043	109.6	0.0	109.6	1.5	122.4	0.0	116.3	79.8	738.7	19%
2044	107.9	0.0	107.9	1.5	126.3	0.0	120.0	82.4	743.0	15%
2045	107.9	0.0	107.9	1.4	131.5	0.0	125.0	86.3	751.2	11%

Generic 8-Hour Storage

Vintage/ Year	Fixed Costs by Vintage	Transmission Adder	Total Resource Fixed Costs by Vintage	Total Generation	Energy Revenues	AS Revenues	Energy + AS Revenues	Energy Value	Marginal GHG Impact	ELCC
	2022$/kW-yr	2022$/kW-yr	2022$/kW-yr	MWh/kW-yr	2022$/kW-yr	2022$/kW-yr	2022$/kW-yr	2022$/MWh	tonnes/MW-yr	%
2024	293.8	0.0	293.8	2.3	64.0	28.6	88.0	38.8	540.5	80%
2025	293.8	0.0	293.8	2.5	79.5	11.1	86.1	34.7	639.5	80%
2026	296.8	0.0	296.8	2.5	84.8	0.9	81.4	32.4	666.3	67%
2027	295.0	0.0	295.0	2.5	92.1	1.0	88.5	34.7	719.2	54%
2028	287.9	0.0	287.9	2.6	102.8	1.2	98.8	37.9	797.8	53%
2029	269.0	0.0	269.0	2.7	119.2	0.5	113.7	42.5	916.9	52%
2030	251.2	0.0	251.2	2.7	130.5	1.1	124.9	46.1	993.3	51%
2031	234.9	0.0	234.9	2.7	134.8	0.3	128.3	47.2	1016.4	54%
2032	226.7	0.0	226.7	2.7	138.4	0.2	131.7	48.2	1034.0	57%
2033	218.5	0.0	218.5	2.7	145.7	0.1	138.5	50.5	1074.3	59%
2034	210.3	0.0	210.3	2.8	148.4	0.1	141.0	51.1	1083.7	62%
2035	203.7	0.0	203.7	2.8	143.7	0.0	136.5	49.5	1040.3	60%
2036	198.9	0.0	198.9	2.8	146.8	0.0	139.5	50.1	1058.8	59%
2037	195.8	0.0	195.8	2.8	154.2	0.0	146.5	51.7	1099.7	57%
2038	192.8	0.0	192.8	2.9	164.9	0.0	156.6	54.7	1159.8	56%
2039	189.7	0.0	189.7	2.9	177.6	0.0	168.7	58.9	1228.5	55%
2040	186.7	0.0	186.7	2.9	192.6	0.0	183.0	64.1	1299.6	53%
2041	183.6	1.0	184.5	2.9	191.0	0.0	181.5	63.3	1248.3	52%
2042	180.5	1.9	182.4	2.9	193.0	0.0	183.3	63.8	1211.2	44%
2043	177.4	2.9	180.3	2.9	194.9	0.0	185.2	64.4	1199.7	36%
2044	174.4	3.8	178.2	2.9	199.8	0.0	189.8	66.2	1202.7	28%
2045	174.4	4.8	179.2	2.8	207.7	0.0	197.3	70.4	1220.6	20%

5.2.3 Upper and Lower Bounds on Capacity & GHG Avoided Costs

Three additional boundary conditions are imposed in the Integrated Calculation:

(1) A lower bound of $39/kW-yr. is applied to the generation capacity avoided cost. This value reflects the assumed ongoing fixed O&M cost of existing gas resources in the 2022-2023 IRP PSP inputs

and assumptions.[21] The application of this floor is intended to ensure that the outputs of the Integrated Calculation also provide sufficient value to retain natural gas resources included in the PSP for their resource adequacy value.

(2) The floor for the GHG avoided costs is set equal to the forecast for cap-and-trade allowance prices used in the IRP, similar to previous ACC cycles. A GHG avoided cost that is equal to the cap-and-trade price would have a GHG adder of $0/tonne.

(3) For years 2040 and 2045, the *maximum* generation capacity avoided cost is set at $39/kW-yr. This is because in later years, energy and GHG revenues alone are sufficient to cover storage costs. The lack of need for additional capacity value for new storage resources in later years leads to the model being under-constrained. Without setting additional constraints, such as setting the capacity avoided costs to be the floor, the optimization has too many degrees of freedom, yielding solutions that are theoretically optimal but practically unbounded.

5.3 Integrated Calculation Results

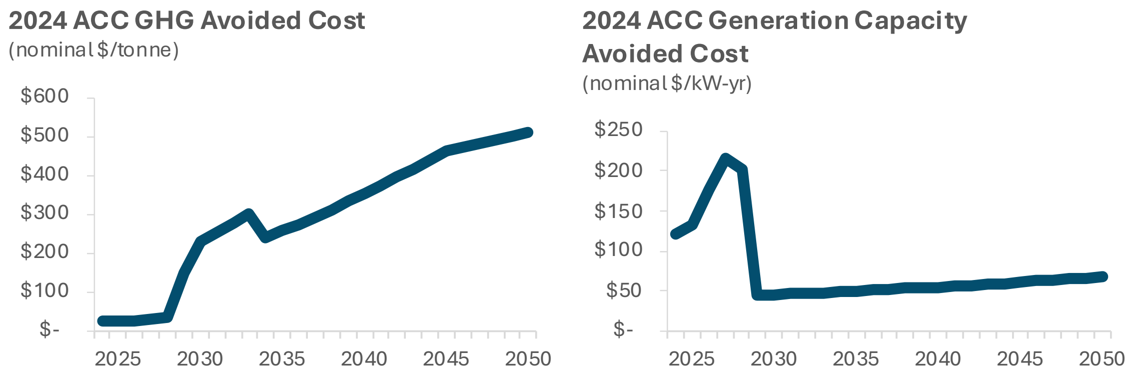
5.3.1 Annual Values for Generation Capacity & GHG Avoided Costs

Based on the methodology, inputs, and assumptions described above, the Integrated Calculation produces avoided costs for GHG emissions and generation capacity for each year of the planning horizon summarized in Figure 5-3.

- GHG avoided costs begin at the cap-and-trade price but rise quickly between 2029 and 2034 as the GHG planning target requires investments in new clean resources; thereafter, the avoided cost of GHGs rises slowly through the remainder of the planning horizon as the declining value of new renewable resources more than offsets their continued cost declines.
- The trajectory for generation capacity avoided costs follows a different trajectory: avoided generation capacity costs are relatively high in the near term, reflecting the high incremental costs of new resources necessary to ensure reliability in the near future, but decline over time as the combined energy and GHG value of supply-side resources is largely sufficient to cover their costs.
- The coordinated movement of the two avoided costs (for example, the simultaneous rise of GHG avoided costs and decline of generation capacity avoided costs from 2028-2030) is a natural outcome of the Integrated Calculation method, as higher values in one avoided cost stream reduce the residual value that the other must provide to make representative resources whole.

[21] Inputs & Assumptions of 2022-2023 IRP, October 2023, Fixed O&M costs for baseline gas resources, page 30, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf

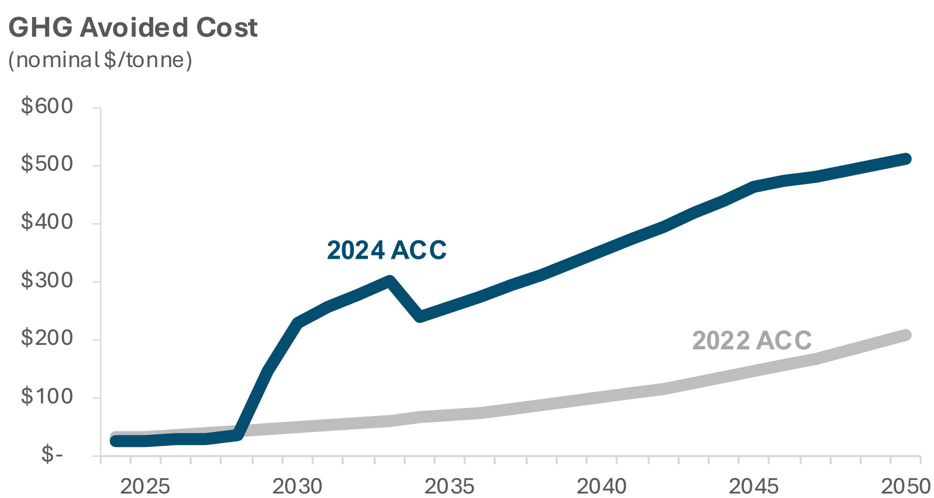
Figure 5-3. Annual avoided costs for GHG emissions and generation capacity



5.3.2 Drivers of Changes from 2022 to 2024

Figure 5-4 compares the GHG avoided costs between the 2022 and 2024 ACC. The avoided cost of greenhouse gas emissions in the 2024 ACC is higher than in the 2022 ACC throughout most of the planning horizon. Multiple factors – both methodological and related to data and assumptions – contribute to this outcome.

Figure 5-4. Comparison of GHG avoided costs, 2022 ACC and 2024 ACC



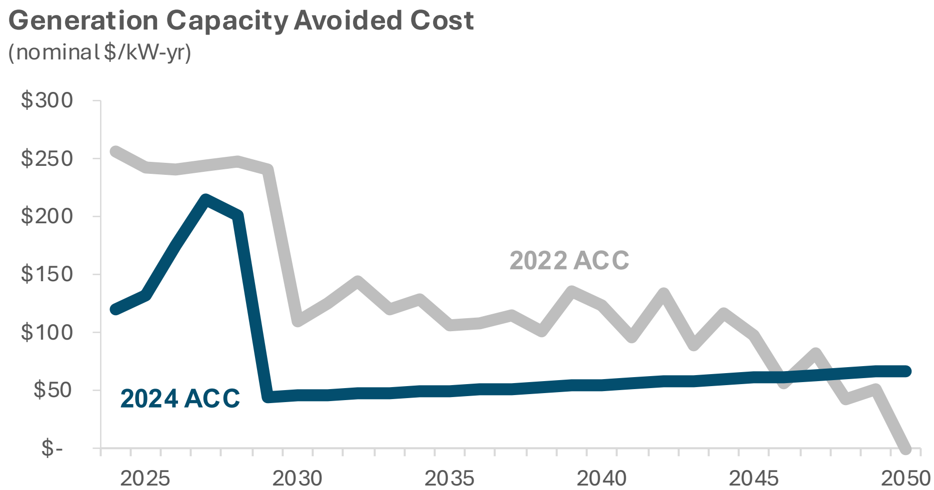
First, it is noteworthy to highlight how the shift in methodology impacts the results of this calculation. In the 2022 ACC, the GHG avoided cost was determined by escalating/deescalating the 2035 GHG shadow price produced by RESOLVE across the entire planning horizon, implicitly tying the value of GHG reductions over the whole period to assumed resource costs and system dynamics observed in 2035. In contrast, the Integrated Calculation produces a GHG avoided cost for each year that explicitly considers the conditions on the grid, the costs of resources that could enable GHG reductions, and anticipated future conditions. Therefore, whereas the 2022 GHG avoided cost was a smooth curve assumed to escalate at utility WACC, the year-by-year changes in the 2024 ACC are an explicit representation of the changing cost of GHG abatement over time based on the evolution of the power system.

In addition to the methodological difference, several key updates to inputs and assumptions contribute to higher GHG avoided costs across the planning horizon:

1. The 2023 PSP includes a more stringent GHG planning target than the prior PSP, aiming for 25 MMT CO2 statewide by 2035. The increased stringency of the GHG planning target naturally places upward pressure on the marginal cost of GHG reductions, as achieving a more stringent target requires investments in more costly resources and results in further decline in the energy value and marginal greenhouse gas impact of new resources due to market saturation effects.
2. Since the 2022 ACC, costs for most new resources – and in particular, solar and storage – have risen as a result of general inflation and supply chain disruptions. The higher costs of new resources directly increase the cost of carbon abatement. Additionally, assumed resource cost *reductions* in the late 2020s and early 2030s create further upward pressure on GHG avoided costs due to an intertemporal opportunity cost (avoiding an investment in a resource in one year may allow that same resource to be developed in the next year at a lower cost). This dynamic is similar to the effect produced by the real economic carrying charge methodology used in the 2022 ACC for generation capacity avoided costs, where projected declining costs for energy storage contributed to high near-term generation capacity avoided costs.

Figure 5-5 compares the generation capacity avoided costs between the 2022 and 2024 ACC. The generation avoided capacity costs determined in the Integrated Calculation in the 2024 ACC are lower than the values used in the 2022 ACC. While the same updates to inputs and assumptions discussed above impact the calculation of generation capacity avoided costs as well, the most significant reason for this result is related to the updated methodology. The Integrated Calculation recognizes that energy storage resources contribute to meeting the GHG planning targets by storing renewable energy during periods of surplus and discharging to reduce utilization of emitting resources, an operational dynamic captured in the marginal GHG impact. Across most of the planning horizon, the combined energy value and GHG value attributed to storage resources is more than sufficient to cover the costs of those resources, resulting in generation capacity avoided costs at the floor throughout much of the horizon. This outcome reflects the interdependence between the GHG and generation capacity avoided costs.

Figure 5-5. Comparison of generation capacity avoided costs, 2022 and 2024 ACC



5.3.3 Implied Value of Representative Resources

Comparing the cost of each representative resource with the combined energy, generation capacity, and greenhouse gas value attributed to it on a net present value basis additional insight into the results, their drivers, and the behaviors of the Integrated Calculation.

Figure 5-6 compares the net present value cost and values for generic solar resources for each new resource vintage between 2024 and 2045. These values are closely aligned throughout the planning horizon, indicating that throughout the period, the energy, generation capacity, and GHG avoided cost components are closely calibrated to the cost of new utility-scale solar.

Figure 5-6. NPV cost vs. value for new generic solar resources by vintage

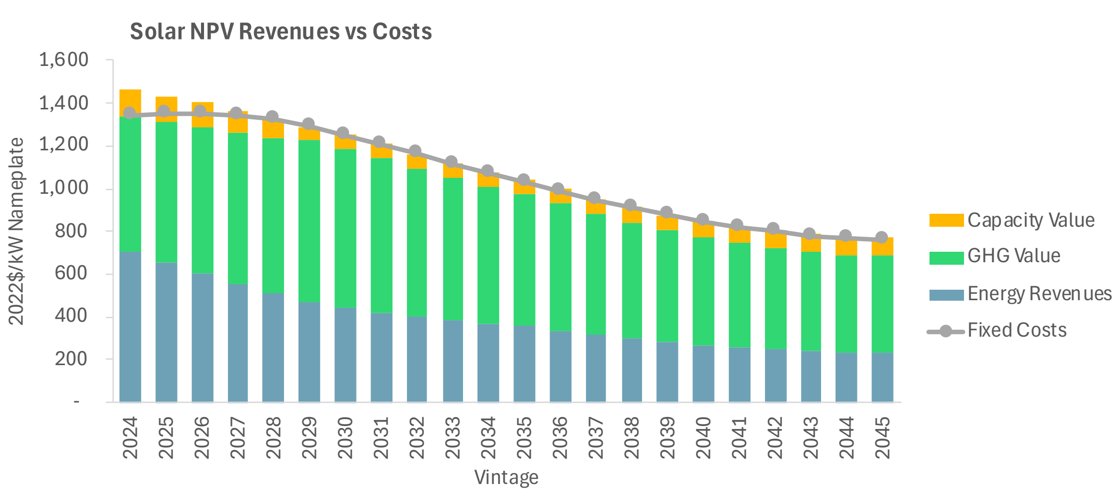
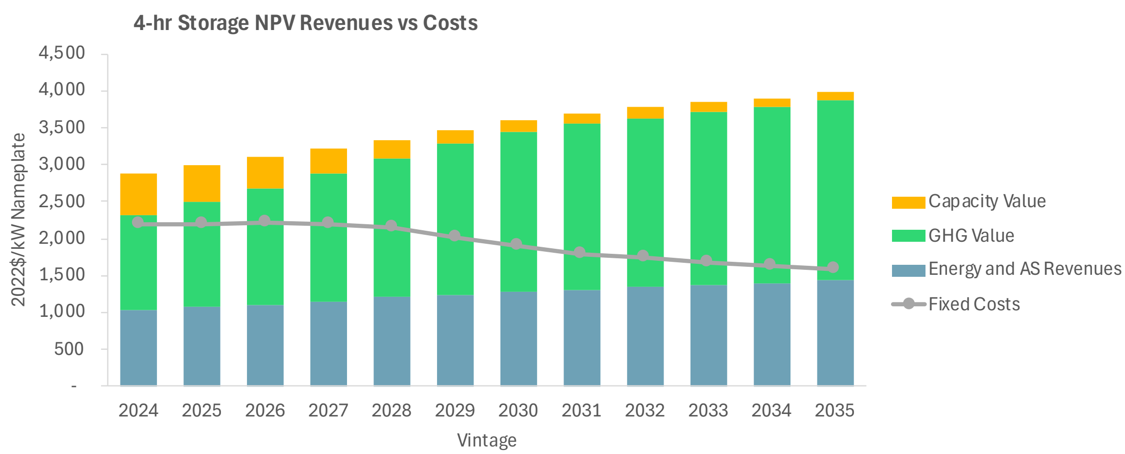
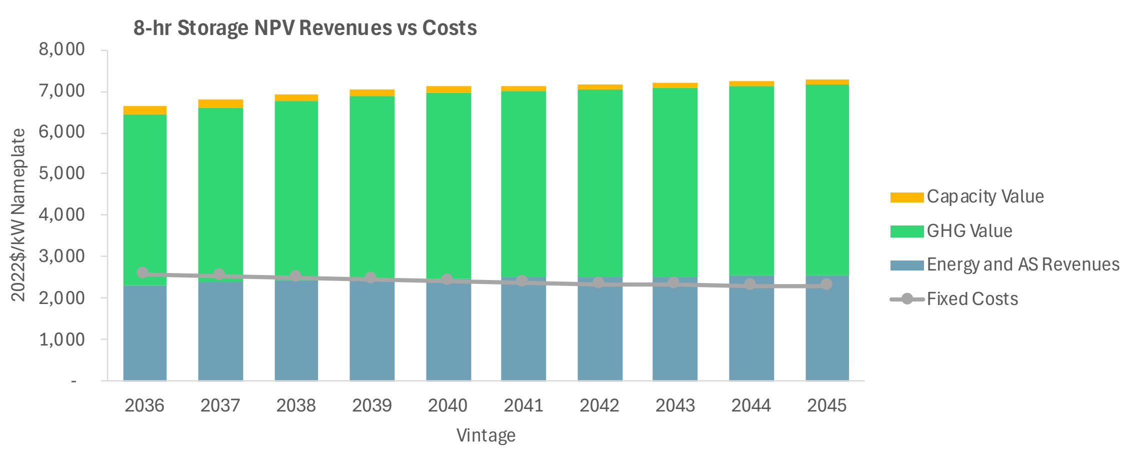


Figure 5-7 shows a similar plot for new energy storage resources. In this case, the combined energy, capacity, and greenhouse gas values attributed to energy storage resources exceed their costs throughout the planning horizon; the gap between the two is comparatively small in the near term but increases in the long term. As described in Section 5, the energy prices produced by SERVM do not account for how hour-to-hour prices may re-equilibrate across periods of storage dispatch, which may lead to overestimates of the energy value and GHG impacts of marginal storage resources. This effect would become increasingly pronounced as the penetration of storage in the system increases.

Figure 5-7. NPV cost vs. value for new generic energy storage resources by vintage





5.3.4 Comparison to RESOLVE Shadow Prices

The outputs of the Integrated Calculation can also be compared to the implied values of generation capacity and greenhouse gas emissions produced by RESOLVE produced in the development of the PSP. RESOLVE includes constraints in each year that require the portfolio meet a minimum planning reserve margin and achieve a specified greenhouse gas emissions target, and the "shadow prices" on these constraints produced by the optimization represent the marginal costs of meeting those constraints.

There are multiple reasons that the shadow prices produced by RESOLVE would not be expected to align exactly with the calculated avoided costs of generation capacity and greenhouse gas emissions. The most significant of these reasons include:

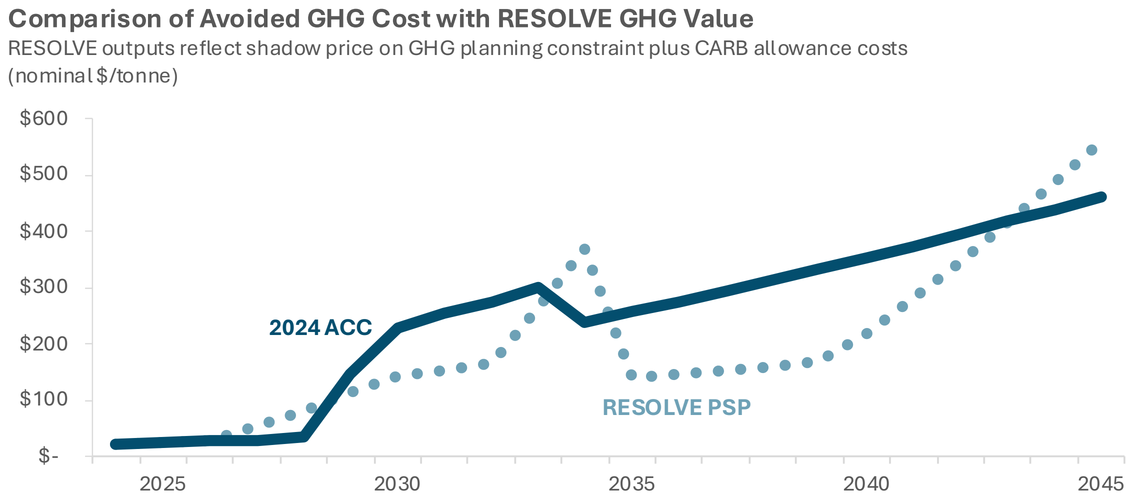
- Through 2035, the PSP includes requirements for specific resources that shape the portfolio according to resource plans submitted by the LSEs; these requirements have a confounding effect upon the marginal costs of GHG and generation capacity as reflected in the shadow prices. For instance, in some years in the near term, the LSE plans include sufficient resources to meet the PRM requirement, which results in a non-binding constraint and a shadow price of zero despite the fact that investment in new capacity resources has been identified as necessary to meet the state's reliability needs.
- As described in Section 5, the energy prices produced by SERVM do not account for how hour-to-hour prices may re-equilibrate across periods of storage dispatch, which may lead to overestimates of the energy value and GHG impact of marginal storage resources. These dynamics differ from the implicit energy value ascribed to energy storage in RESOLVE, in which the hourly energy shadow prices become increasingly flat during evening and overnight periods at increasing penetrations of storage. The presence of some differences in the underlying energy price signals between the two models naturally contributes to differences in dependent calculations (including generation capacity and GHG avoided costs).

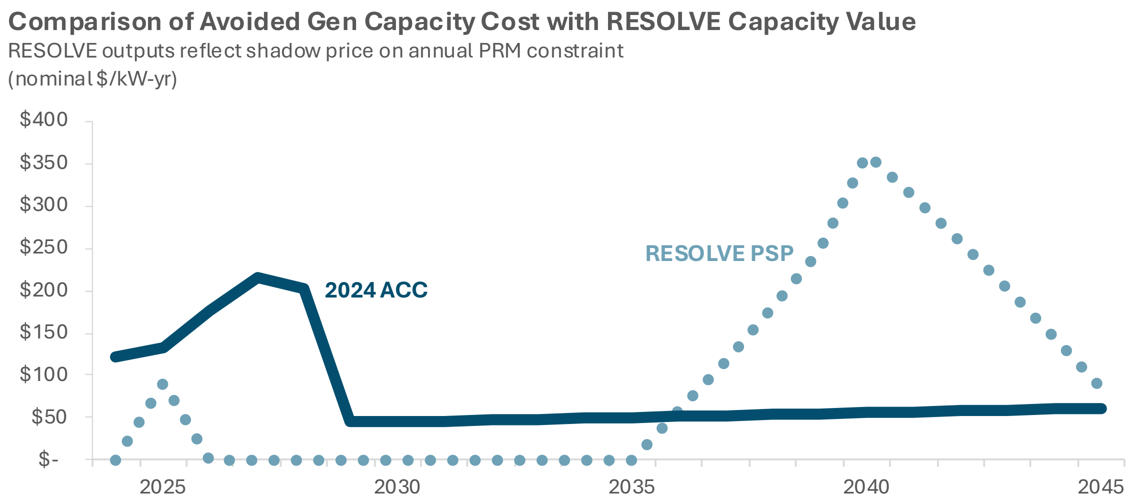
Despite these differences, the shadow prices produced by RESOLVE are useful reference points to contextualize the levels and trends observed in the avoided greenhouse gas emissions and generation capacity costs. This comparison is shown in Figure 5-8.

- From 2025-2030, the GHG values produced by the two models are similar, beginning at the cap-and-trade price and increasing towards the end of the period as the GHG planning targets begin to bind. With respect to generation capacity value, RESOLVE shows a very low value in this period, a result driven by (1) the forced inclusion of LSE plans directly in the PSP and (2) the complementary MTR constraint requiring new resources in the near term; the higher value observed in the Integrated Calculation for the 2024 ACC is explicitly capturing the costs of those resources needed to meet near-term reliability needs.
- Between 2030 and 2035, the two models show similar dynamics: continuing increases in GHG values and low generation capacity values. The continued GHG emissions reductions required in the PSP make GHG value the more pronounced driver of new resource investments across this period (rather than generation capacity value, which is low in both models).
- Between 2035 and 2040, the RESOLVE shadow prices show lower GHG values and higher generation capacity values than the Integrated Calculation. It is noteworthy that these differences are in offsetting directions, once again indicating the interactive tradeoff between GHG and generation capacity value. Because SERVM energy revenues for energy storage resources are relatively high (indicating the net cost of generation capacity would be low), the higher GHG avoided cost produced by the Integrated Calculation is an expected result.
- By 2045 (the final year of RESOLVE's planning horizon), RESOLVE's generation capacity value has returned to a much lower value, and the GHG value increases once again. This tracks closely with the outcome of the Integrated Calculation.

Overall, while differences between the results of the two models exist, the comparison between the two and the explanation of more notable differences suggests that the results of the Integrated Calculation are properly capturing the general trends of resource value.

Figure 5-8. Comparison of implied values for greenhouse gas emissions and generation capacity produced by RESOLVE with calculated values in the ACC





5.4 Hourly GHG Avoided Costs

The Integrated Calculation described above produces an annual GHG avoided cost that represents the sum of two values:

- Cap-and-Trade: The explicit carbon cap and trade allowance cost captured in real-world energy prices, which represents the short-term cost of purchasing carbon allowances.

- GHG adder: the implicit value of carbon representing the additional costs incurred by utilities to procure renewable and storage resources needed to support the state's decarbonization goals (represented by the "GHG Adder," as adopted by the CPUC).[22]

For the purposes of valuing DERs based on hourly profiles, the annual GHG avoided cost is translated to an hourly stream that is inclusive of two components (similar to previous ACC cycles):

1. **Hourly Marginal GHG Avoided Costs:** In each hour, the annual GHG avoided cost is multiplied by a short-run marginal emissions factor (derived from SERVM as described in Section 3.4) to determine the hourly marginal GHG avoided costs. This represents the GHG value provided by a resource assuming a static emissions target for the electric sector.
2. **Portfolio Rebalancing:** The avoided costs also include a "portfolio rebalancing" component intended to capture how changes in electric sector load may lead to changes in the absolute greenhouse gas planning target for the electric sector (i.e. 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). This component is determined based on the average greenhouse gas intensity of the portfolio produced by RESOLVE. The approach implemented for the ACC is similar in concept to the approach used for the fuel substitution test (D. 19-08-009), described in the Fuel Substitution Technical Guidance Version 1.1.[23] The CEC also uses a similar approach for the 2022 Title 24 TDV.[24]

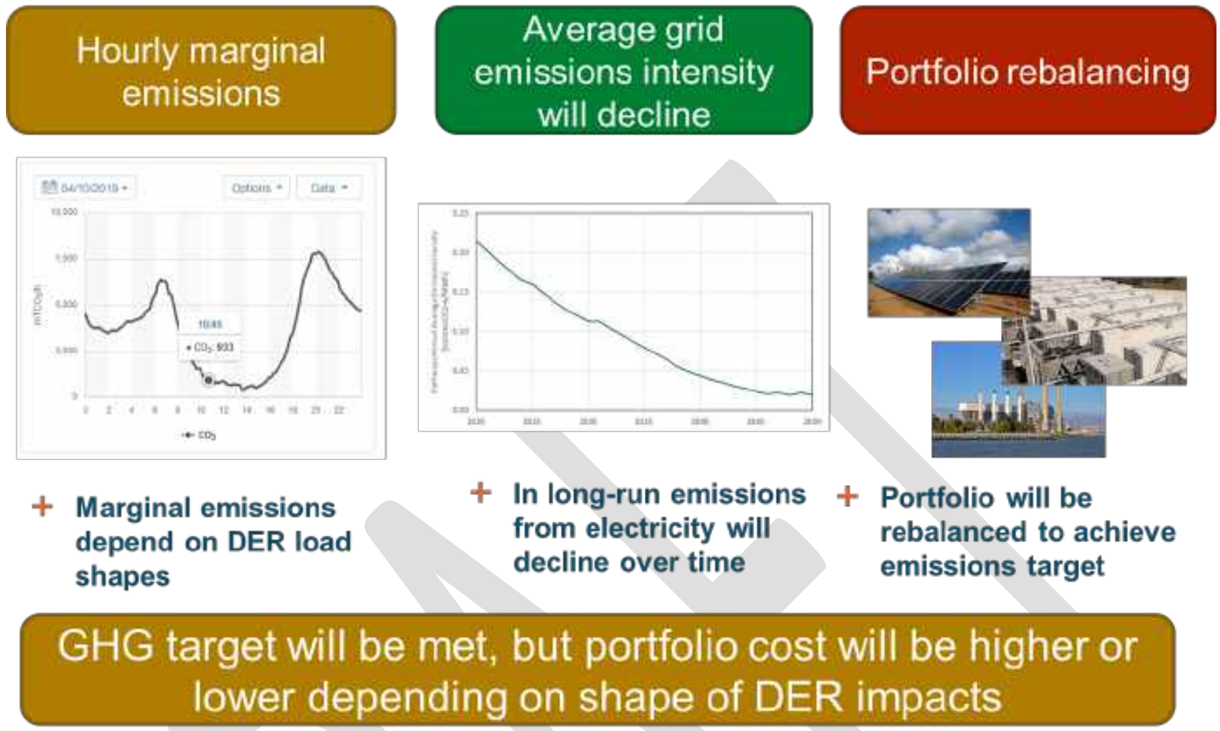
These two components are illustrated in Figure 5-9~~Figure 5-9~~.

[22] D.18-02-018, Table 6. Note that in Table 6 of this IRP Decision, the term "GHG Adder" is used, inconsistent with the usage in IDER, to represent the combined value of the monetized cap and trade allowance price and the non-monetized residual value (rather than only the residual, non-monetized value).

[23] Fuel Substitution Technical Guidance for Energy Efficiency, V.1.1, October 31, 2019, Appendix A at Figure 1.

[24] Documentation is in development and will be published in the 2022 Energy Code Pre-Rulemaking Docket Log: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-BSTD-03

Figure 5-9. GHG Emission Impact Estimation for DERs



5.4.1 Hourly Marginal GHG Avoided Costs

As described in section 3.4, hourly marginal emission factors are derived from SERVM energy prices. These hourly marginal emissions factors, expressed in metric tons per MWh, are multiplied by the annual GHG avoided cost to produce hourly marginal GHG avoided costs. Because the marginal emissions factors are directly proportional to the price of energy (calculated as described in Section 3.4), the hourly marginal GHG avoided costs exhibit the same general patterns throughout the year: across the horizon, hourly marginal GHG avoided costs tend to be lowest during daytime hours when the system is saturated with solar and highest during the evening and overnight periods when higher cost marginal resources must be operated to serve load.

5.4.2 Portfolio Rebalancing

The marginal emissions impact of adding or decreasing load provides only a partial picture; in measuring the impact of changes in load, it is also necessary to account for how the allowable GHG emissions target would adjust when load is added or removed on the margin. The clearest example is made by considering building and transportation electrification. These measures reduce GHG emissions overall, but add load to the electric system. If electrification load were added to an electric sector IRP portfolio, one would expect the allowable GHG emissions from the electric sector to increase proportionally, not to remain fixed at the original total emissions target.

The ACC is a simplified, static snapshot of the marginal costs for a given electric sector resource portfolio and a given GHG emissions target. The ACC requires a correspondingly simple and straightforward approach to reflect a proportional reallocation of allowable GHG emissions between the transportation, building and electric sectors with increased electrification load. The approach used in the ACC is to use the *average* grid emissions intensity for the modeled IRP portfolio to calculate a Step 2 portfolio rebalancing impact. The simplifying assumption is to assume the average grid intensity is a reasonable reflection of the electric sector's proportional responsibility for meeting California's total GHG emissions target. Thus, when considering incremental load growth from electrification, the allowable GHG emissions from the electric sector increases proportionally, and the allowable increase is the incremental load in kWh times the average grid emissions intensity in GHG/kWh.

5.4.2.1 Implementation of the GHG Portfolio Rebalancing in the ACC

The rebalancing is based on annual average emission intensity levels. It is calculated as:

Rebalancing Cost_y (\$/MWh) = - Emissions Intensity_y (tonnes/MWh) * GHG Adder Cost_y (\$/tonne)

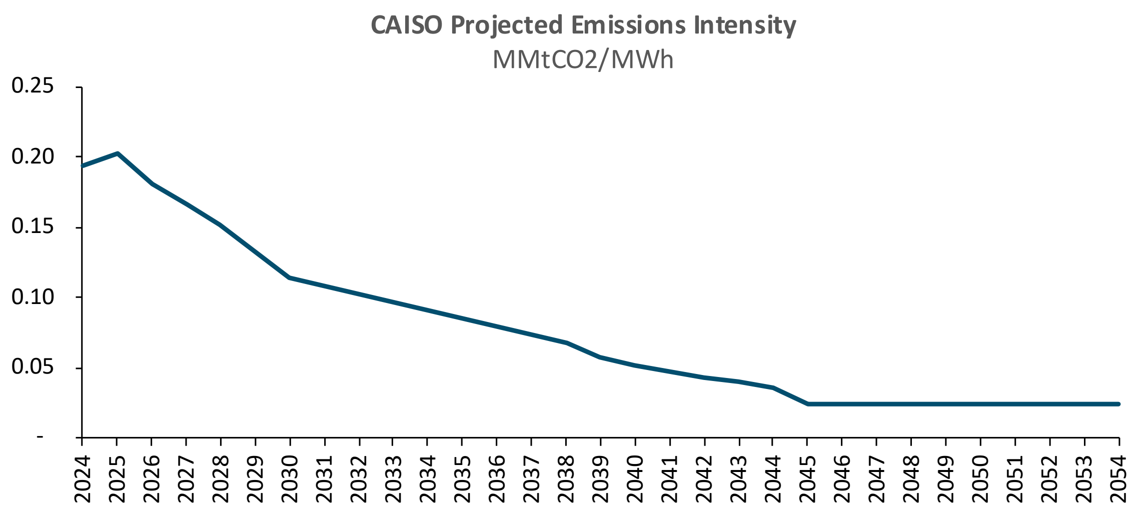
Within a year the rebalancing costs (\$/MWh) are the same for all hours. Note that the rebalancing cost is presented as a negative value consistent with the presentation of avoided costs as positive benefits associated with load reductions. In the case of the rebalancing costs, a program that reduces load would incur a rebalancing disbenefit, that is, rebalancing would reduce the avoided cost benefits of the program. Conversely for a program that increases load, the rebalancing costs would reduce the net cost increases associated with the program.

5.4.2.2 Average Annual Electric Grid GHG Emissions Intensity

RESOLVE capacity expansion modeling in the IRP determines the least-cost resource portfolio for meeting electricity sector GHG emission targets. The portfolio will achieve increasingly lower GHG emissions intensity over time. Figure 5-10~~Figure 5-10~~ depicts the annual emissions intensity trajectory derived from the IRP RESOLVE modeling. Emissions intensity is calculated as tonnes of GHG per MWh of retail sales to be consistent with SB100 language that zero-carbon resources supply 100% of retail sales of electricity to end-use customers in 2030. The formula for calculating average intensity factors is shown here, for year *t*:

$$Emissions\ Intensity_t(\frac{tCO_2}{MWh}) = \frac{Total\ CAISO\ Emissions_t(tCO_2)}{Total\ Retails\ Sales_t\ (MWh)}$$

Figure 5-10. CAISO Projected Emissions Intensity, 2023 IRP Preferred System Plan Results



5.5 Hourly Allocation of Generation Capacity Value

The annual generation capacity avoided costs ($/kW-yr.) produced by the Integrated Calculation are allocated to the hours of the year that exhibit the greatest risk of reliability events based on SERVM modeled reliability event timing. Allocating generation capacity avoided costs in this manner is intended to value resources based on their marginal contributions to system reliability (or, in other words, based on their ability to improve system reliability).

Based on the electric demand and generation profiles used in the PSP RESOLVE case, staff studied the PSP case in SERVM to determine the timing and magnitude of Expected Unserved Energy (EUE) events. These results are based on simulations of a system tuned to total Loss of Load Expectation (LOLE) of 0.1 (1 expected event in ten years), which is the industry standard. SERVM simulated 23 years of hydro variability with 23 weather years of weather variability, and 5 levels of demographic uncertainty in future years to total 2645 cases for each future year. The SERVM model determines the expected unserved energy (EUE) for each month/hour period in the year based on a dataset from the PSP RESOLVE cases. It is expected that as solar and storage are installed on the grid, LOLE events gradually migrate to later in the evening. EUE will increasingly reflect risk at the “Net Load” peak, which no longer occurs in the mid-afternoon when overall electric demand is highest. Instead, reliability risk will occur when solar and storage are largely expended for the day and demand is met with residual thermal capacity and imports.

The reliability simulations used to allocate generation capacity avoided cost to hours in the 2024 ACC incorporate new storage dispatch logic in SERVM to more accurately capture the marginal reliability value of energy production in hours outside of modeled loss of load hours. This approach was implemented by “spreading out” loss of load over all hours in which additional energy could reduce EUE. This recognizes that incremental energy production in hours prior to loss of load could preserve battery state of charge for the critical hours. To implement this approach, Astrapé has modified the way in which storage is discharged.

- A counterfactual dispatch is produced on days with loss of load.

- The dispatch of storage resources that were exhausted at the time of loss of load was redistributed to shave the net load peak.
- This results in an equal distribution of EUE across all hours at which the referenced storage resources were dispatched or there was a capacity shortfall.

The profile of EUE events driven by pure capacity shortfalls (e.g. not driven by energy storage exhaustion) were not adjusted. Resulting month-hour average EUE values for 2026, 2030, 2035, and 2040 are shown below in Figure 5-11~~Figure 5-11~~ and Figure 5-12.

Figure 5-11. 2026 Expected Unserved Energy [MWh] from SERVM

Month\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1																								
2																								
3																								
4																								
5																								
6																								
7																		0.1	1.0	0.5				
8						0.0									0.1	0.6	45.5	46.5	48.2	52.6	47.8	47.5	0.1	
9																0.5	3.2	21.5	30.0	12.9	3.8	3.8	0.2	
10																								
11																								
12																								

Figure 5-12. 2030 Expected Unserved Energy [MWh] from SERVM

Month\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1																								
2																								
3																								
4																								
5																								
6																								
7																	0.0	0.4	2.2	1.5	0.4	0.4	0.4	0.3
8															0.4	2.9	24.1	45.7	46.9	49.1	48.9	48.9	5.2	4.6
9															0.1	1.2	9.2	38.3	35.5	17.5	14.7	14.5	8.7	4.8
10																								
11																								
12																								

Figure 5-13: 2035 Expected Unserved Energy [MWh] from SERVM

Month\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1																								
2																								
3																								
4																								
5																								
6																								
7																	0.8	3.7	3.7	3.7	3.7	3.7	3.7	3.5
8	0.1														10.1	14.5	59.5	79.2	81.3	84.6	84.3	84.4	84.4	82.0
9	2.0	0.1				0.2	0.2	0.2	0.2		0.5	0.5	1.0	5.2	6.8	58.4	96.8	115	125	133	133	134	90.6	89.6
10																								
11																								
12																								

Figure 5-14: 2040 Expected Unserved Energy [MWh] from SERVM

Month\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1																								
2																								
3																								
4																								
5																								
6																								
7	4.3	0.0												0.2	0.4	2.8	5.4	11.0	15.4	17.2	16.6	16.0	17.0	16.1
8	2.1												0.4	2.8	4.8	11.8	32.4	55.8	60.2	66.0	63.2	51.8	47.7	42.3
9	31.4	0.1						0.1					0.1	0.3	1.0	7.3	29.2	47.6	52.5	58.2	58.5	48.5	44.6	42.9
10																								
11																								
12																								

These month/hour EUE values were then allocated to days of the year using the CTZ22 temperature data and the 2018 calendar year for consistency with energy prices. A load-weighted daily maximum statewide temperature is calculated and all hours in days where the temperature exceeds a threshold receive the corresponding month/hour EUE value from SERVM. The temperature threshold was calculated as one standard deviation below the highest temperature, resulting in a temperature threshold of 87 F. The allocation factors between modelled years are interpolated. Years before 2026 use 2026 allocation factors, and years after 2040 use 2040 allocation factors.

6 Transmission Avoided Capacity Costs

6.1 Background

The 2024 ACC update relies on the same general methodology as was used for the 2022 ACC to calculate transmission avoided costs for SCE and SDG&E. Changes made to improve consistency between utilities and incorporate updates to utilities' project data are noted in section 12.3. For PG&E, the transmission avoided cost value remains unchanged from the 2022 ACC update except for escalation adjustments. Though PG&E estimates transmission avoided costs in its GRC filings, the value used in the 2022 and 2024 ACC updates reflects an avoided cost value proposed by the Solar Energy Industries Association and adopted by the CPUC in its D.21-11-016 ruling. Transmission avoided costs for SCE and SDG&E are calculated using the Discounted Total Investment Method (DTIM) for system-wide projects and Locational Net Benefits Analysis (LNBA) for individual large projects. Inputs are provided by each utility in response to individual data requests. The final values for all three utilities are listed in Table .

Transmission avoided capacity costs represent the potential cost impacts on utility transmission investments from changes in peak loadings on the utility systems. The paradigm is that reductions in peak loadings via customer demand reductions, distributed generation, or storage could reduce the need for some transmission projects and allow for deferral or avoidance of those projects. The ability to defer or avoid transmission projects would depend on multiple factors, such as the ability to obtain sufficient dependable aggregate peak reductions in time to allow prudent deferral or avoidance of the project, as well as the location of those peak reductions in the correct areas within the system to provide the necessary reductions in network flows.

This avoided cost update does not look to evaluate whether any particular technology, measure, or installation could provide transmission avoided cost savings. Those determinations should be made in the proceedings in which these avoided costs are applied. The values developed herein represent the value provided IF the peak loading reductions can be obtained in the right amount, right location, and with the right dependability.

It should also be noted that the locations of the needs for demand reductions or distributed generation or storage will move over time as loadings on the utility systems evolve differently in different areas within the utility service territories. Thus, over the next ten years there could be a value to load reductions in area A, but not area B; but in years 10-20 the situation may flip, and area B could become the area with a need for load reductions, while area A no longer has a need. Given this locational and temporal uncertainty, the transmission avoided capacity costs are presented as a simple system average value for each utility. While this may underestimate the value of net load reductions in some areas and overestimate in other areas, the consultant believes that this approach is superior to trying to forecast locational needs far into the future. Details on the calculation of the utility-specific transmission costs are included in Appendix 12.3.

Table 6-1. Long-Term Transmission Marginal Costs ($2023)

	PG&E	SCE	SDG&E
Transmission Capacity ($/kW-yr.)	$53.21	$~~24.47~~49.95	$39.64

6.2 Annual Transmission Marginal Capacity Costs

The transmission capacity marginal costs are escalated to nominal dollars using the annual transmission escalation rates shown below. The escalation rates were provided by the utilities in their responses to the Energy Division data request for the 2024 ACC update. Values for all three utilities have decreased from the 2022 ACC update. The utilities noted that escalation rates used in transmission planning may vary annually or by project based upon the forecast conducted during project planning. The values in Table 6-2 are an average across years in the near-term transmission planning horizon.

Table 6-2. Transmission Escalation Rates

PG&E	SCE	SDG&E
0.72%	1.99%	1.95%

The annual transmission capacity costs by utility are shown in Table .

Table 6-3. Annual Transmission Marginal Capacity Costs ($ Nominal)

Year	PG&E	SCE	SDG&E
2023	$53.21	$24.47	$39.64
2024	$53.59	$24.95	$40.41
2025	$53.98	$25.45	$41.20
2026	$54.37	$25.96	$42.00
2027	$54.76	$26.47	$42.82
2028	$55.15	$27.00	$43.65
2029	$55.55	$27.54	$44.50
2030	$55.95	$28.09	$45.37
2031	$56.35	$28.65	$46.26
2032	$56.76	$29.22	$47.16
2033	$57.17	$29.80	$48.08
2034	$57.58	$30.39	$49.02
2035	$57.99	$30.99	$49.97
2036	$58.41	$31.61	$50.95
2037	$58.83	$32.24	$51.94
2038	$59.25	$32.88	$52.95
2039	$59.68	$33.54	$53.99
2040	$60.11	$34.20	$55.04
2041	$60.54	$34.88	$56.11
2042	$60.98	$35.58	$57.21
2043	$61.42	$36.29	$58.32
2044	$61.86	$37.01	$59.46
2045	$62.30	$37.75	$60.62
2046	$62.75	$38.50	$61.80
2047	$63.21	$39.26	$63.00
2048	$63.66	$40.04	$64.23
2049	$64.12	$40.84	$65.49
2050	$64.58	$41.65	$66.76
2051	$65.05	$42.48	$68.06
2052	$65.51	$43.33	$69.39
2053	$65.99	$44.19	$70.75
2054	$66.46	$45.07	$72.12

6.3 Hourly Allocation of Transmission Avoided Capacity Costs

The annual capacity costs shown in Table are allocated to hours of the year to allow the ACC to reflect the time-varying need for transmission capacity. The peak capacity allocation (PCAF) method used to estimate distribution allocation factors in the prior ACC updates has been applied to the UTILITY system-level hourly loads to estimate the transmission hourly allocation factors. 2023 Historical system loads were taken from the CAISO Energy Management System dataset[25]. CAISO averaging methods during daylight savings hours were removed to generate a true 8760 hourly load profile, aligned with the CTZ22 weather year.

[25] CAISO Historical EMS Load Data can be found here: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx#Historical

The PCAF method allocates capacity costs to the hours of highest load where each utility system is most likely to be constrained and require upgrades, with the additional constraint that the peak period contains between 20 and 250 hours for the year.

PCAF[a,h] = (Load[a,h] – Threshold[a]) / Sum of all positive (Load[a,h] – Threshold[a])

Where:

a is the utility,

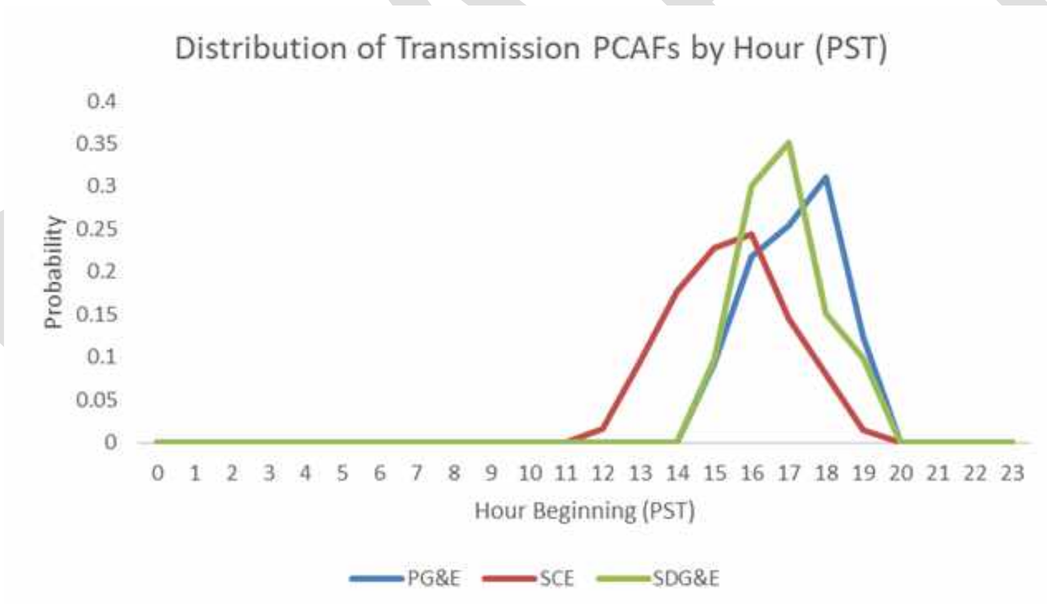
h is hour of the year,

Load is the net utility load on the grid, and

Threshold is the utility maximum demand less one standard deviation, or the closest value that satisfies the constraint of between 20 and 250 hours with loads above the threshold.

The approach to performing day and weather year mapping is detailed in section 7.6.1. This same approach was used to reallocate transmission PCAFs. The consultant aggregated climate zone temperature data to temperature profiles for each utility by taking the weighted average of temperature based on the load of each climate zone in each utility.

Figure 6-1. Transmission PCAF Allocators by UTILITY



7 Distribution Avoided Capacity Costs

The 2024 ACC update recalculates the avoided distribution capacity costs using similar methodology to prior ACC updates and with detailed 2023 GNA and DDOR information provided by each utility.

Distribution avoided costs represent the value of deferring or avoiding investments in distribution infrastructure through reductions in distribution peak capacity needs. The Distribution Resources Plan (DRP) proceeding developed considerable insight and data related to the impact of DERs on the distribution system. Specifically, the Energy Division T&D White Paper attached to the DRP's June 13, 2019 ALJ Ruling[26] defines two types of avoided costs, specified and unspecified, and proposes to leverage information from utility DDOR and GNA filings that contain detailed information about utility needs and investment plans. The avoided costs developed herein leverage information from those reports to estimate near-term distribution marginal costs (for years one through five of the forecast) based on the recommendations in the T&D White Paper.

The distribution marginal costs then transition to GRC distribution marginal costs for the long-term values. Such GRC-sourced marginal costs have been a staple in the ACC in the past.

7.1 Near-term Distribution Marginal Costs from Distribution Planning

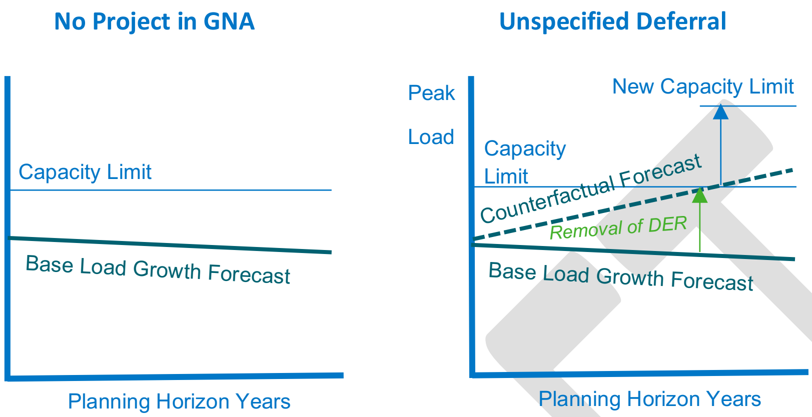
The utilities calculate distribution avoided costs as part of the annual DDOR process. These avoided costs are specific to a small number of utility capacity projects that could potentially be deferred via DER adoptions in the project areas. The DDOR avoided costs represent the value of deferring distribution investment projects through the addition of DER or other load reducing measures that are *above and beyond* the DER growth the utility expects in the project area because of current DER policies, incentives, and programs. The T&D White Paper defines these DDOR costs as **"specified deferrals."**

The challenge is that specified deferrals are not theoretically well-suited to determining the avoided distribution costs that could be provided by the DER that the utilities have embedded in their planning forecasts. Instead, the need for a capacity-driven distribution project is determined by the intersection of the capacity limit with the load growth forecast. In some cases, the load growth forecast may not intersect the capacity limit because of the expected peak load reductions from new embedded DERs. However, if that new embedded DER were removed from the forecast, there could have been a need for a capacity project.

This is illustrated in Figure 7-1, where the chart on the left represents the GNA analysis for a circuit that shows no need for a capacity project within the five-year planning horizon. The chart on the right shows the effect of the removal of the new DER growth from the load forecast. The removal of the new embedded DER increases the loading on the equipment and results in higher deficiencies as well as the need for incremental projects over the five-year planning horizon (compared to the utility planning forecasts). The No New DER local load forecasts are referred to as the "counterfactual" forecasts in the T&D White Paper.

[26] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 13, 2019

Figure 7-1. Project need from counterfactual forecast



The concern with how to estimate marginal costs under the No New DER paradigm prompted the effort to quantify **"unspecified deferrals"** and the associated marginal distribution cost. For the ACC, the near-term marginal distribution capacity costs are the system average marginal costs under the counterfactual forecast for each utility. The marginal costs of the specified deferrals are not included in the ACC as the ACC modeling is done at the system and climate zone level, and the ACC would not currently accommodate the geographic specificity that would be necessary for the specified deferral cases. Instead, the marginal costs of specified deferrals should be applied with the already established DDIF process.

To calculate the marginal cost under the counterfactual forecast, the consultant implemented the method put forth in the T&D White Paper.[27]

1. **Calculate the counterfactual forecast from the GNA:** For each listed circuit, the counterfactual load can be derived by removing the circuit-level DER forecast from the circuit-level load.
2. **Identify potential new capacity projects under the counterfactual forecast:** Identify all circuits that exceed the facility rating in any year of the counterfactual forecast and determine the associated capacity of overload. In the T&D White Paper, this step also identifies projects that *would* have occurred in the planning forecast and excludes those projects from those considered DER-deferrable. This is done to focus on the marginal investment that DERs would defer or avoid, rather than the marginal investments that DERs may not be able to and are not expected to avoid. In prior ACC updates, this exclusion step was omitted in performing the final marginal cost calculations.
3. **Estimate the percentage of distribution capacity overloads that lead to a deferred distribution upgrade:** Calculate a system-level quantity for deferred distribution capacity by using a ratio between capacity overloads identified in the GNA to capacity overloads deferrable in the DDOR. The resulting percentage is a proxy for the percentage of distribution capacity upgrades that can be deferred by DER. Multiplying this percentage with the number of deferrable projects from Step 2 determines the subset of counterfactual capacity projects that could potentially be deferred via DER.
4. **Calculate the average marginal cost of the deferred distribution upgrades:** The average DDOR marginal cost is the sum of the DDOR avoided distribution cost ($/kW-yr.) for each project from the

[27] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 2019, Attachment A, p. 11

DDOR filing, multiplied by its total deficiency need over the planning horizon, and then divided by the total deficiency need for all DDOR projects.

5. **Calculate system-level avoided costs:** Multiply the average DDOR marginal cost found in step 4 by the total quantity of deferred capacity by DERs for each circuit. This product is then divided by the sum of forecasted level of DERs for all areas (not just DDOR areas) to obtain a single, system-level distribution deferral value in $/kW-yr.

This method essentially uses the utilities' GNA planned case to indicate the unit cost to add distribution capacity. A counterfactual forecast that adds back the load reductions of DER embedded in the utility planning cases is then used to calculate a counterfactual distribution capital plan. The counterfactual plan has the same system average distribution unit cost[28] as each IOU's plan and is reduced if needed to reflect that not all forecasted overloads lead to a distribution project. In some cases, low or no cost solutions are available that would allow a circuit or area deficiency to be addressed without a meaningful capital project. The proportion of deficiencies that could be addressed in such a manner are removed from the counterfactual distribution plan.

This counterfactual plan is then converted into a system average marginal cost using standard GRC methods of applying a RECC annualization factor along with loaders or adders, such as administrative & general (A&G) and O&M expenses. Note that while only a fraction of the circuits and areas have need of a capital project even under the counterfactual forecast, the entire forecast amount of DER load reductions is used to calculate the system average marginal cost. This allows the near-term distribution marginal cost to reflect that only a fraction of DER installed in the next five years could contribute to deferring a distribution project over that same time period. However, the distribution marginal capacity costs do increase toward long-term marginal cost levels after year five, reflecting the potential value that could be provided by DERs with load reductions persisting past year five.

Table 7-1. Near-Term Distribution Marginal Costs

	PG&E	SCE	SDG&E
Circuits only		$0.97	
B-Bank Substations		$1.93	
A-Bank Substations		$0.26	
Subtransmission		$0.17	
Total Distribution Capacity ($/kW-yr.)	$1.54 ($2023)	$3.34 ($2023)	$2.38 ($2023)

7.2 Refinements to Near-term Distribution Cost Calculation

The 2024 ACC update remains consistent with the T&D White Paper method approved for calculation of marginal distribution costs and seeks to better align with that method while incorporating updated utility data. To this end, two refinements are made to specific calculations used in the 2022 ACC update.

[28] Unit cost used here is the distribution capital cost per kW of circuit or area deficiency over the five-year planning horizon.

7.2.1 Exclusion of Overloads Deferred by Planned Investments when Determining Incremental DER-Deferred Overload Capacity

The first refinement is described above in relation to Step 2 of the T&D White Paper method. The 2024 ACC update includes a step to exclude capacity needs which are addressed by investments in the existing planning forecast from the total counterfactual overloads. This step is prescribed in the White Paper method and ensures that only the counterfactual capacity need that is incremental and anticipated to be deferrable by DERs is used to calculate the total distribution system costs deferrable by DERs.

The exclusion step was omitted in the 2020-2022 ACC updates both in an effort to reflect a system-wide value -one unaffected by which circuits had anticipated DER growth and thus reduced planned investments- and to align with the fact that the average marginal cost of deferred distribution upgrades (calculated in Step 4 of the T&D White Paper method) factors in costs across all planned investments rather than only a subset that are eligible for deferral from DERs. This omission has been explicitly noted in the documentation of the prior ACC updates. However, it is still reasonable to arrive at a systemwide value when applying the exclusion step, and the practical rationale for including all planned investments in Step 4's weighted average is not directly applicable to Step 2. Therefore, the 2024 ACC update returns to a more direct application of the T&D White Paper Method.

7.2.2 Delineate DER Load-Reducing and DER Load-Increasing Circuits

A second refinement to the near-term distribution calculation addresses sensitivity of the calculations to new data and the types of DERs expected in the utility planning forecasts. For prior ACC Updates, the circuit-level DER forecast used in Step 1 and carried throughout the T&D White Paper Method looked at the net load impact of DERs on the system both when evaluating individual circuits and aggregating across circuits. This has been useful for obtaining a single value for distribution avoided cost, regardless of the type of DER, but can make the calculations sensitive to the forecast in two ways.

First, using the net load impact can result in the distribution capacity value associated with DERs crossing from positive to negative. If there is an overall reduction in load across the system due to DERs, but also an increase in forecasted overloads (shown as a decrease in overloads in the counterfactual when DERs are removed), then the resulting distribution deferral value will be negative. This also applies if there is an overall increase in load across the system from DERs but a decrease in overloads. Both scenarios are possible because the impact of DERs on load may vary by circuit and not all changes in load will result in an overload or the avoidance of an overload at the circuit level.

In an example scenario, the majority of circuits may experience a reduction in load due to load-reducing DERs (such as rooftop solar or energy efficiency) without there being a noticeable impact on the number of overloads or the total overload capacity. At the same time, just a few circuits which are near maximum capacity could experience an increase in load from load-increasing DERs (such as vehicle or building electrification) which pushes them into an overload and is enough to see an increase in the net overload capacity. When all of the forecasted DERs are removed in the counterfactual scenario, the overloads decrease, meaning that level of required investment in the system to address those overloads also decreases despite overall load increasing. Because the distribution deferral value is calculated in terms of avoided investment divided by the total forecasted DER capacity, this gives a negative result. This scenario is more likely to occur when the capacity of load-increasing DERs is similar to that of load-reducing DERs or when load-reducing DERs are concentrated on circuits where load-reduction benefits are not required to avoid overloads but load-increasing DERs are expected in constrained locations. This has not arisen in prior ACC updates, but did occur for the 2024 update when calculating avoided distribution costs for both SCE and SDG&E using the net load impact approach. This also occurred for PG&E in the 2024 update prior to adopting the refinement described in section 7.2.1.

The second drawback of using overall net load impact in the avoided distribution cost calculations is that the magnitude of the distribution deferral value can be affected by the difference between the number of forecasted load-increasing and load-reducing DERs. This is especially likely to skew results when the capacity of load-increasing DERs is similar to that of load-reducing DERs. Where the distribution deferral value is calculated in terms of avoided investment divided by the net forecasted DER capacity, if there is a scenario where many circuits would be overloaded in the counterfactual scenario (meaning high avoided investment) and there is just a slightly greater capacity of load-reducing or load-increasing DERs forecasted system-wide, then the denominator becomes very small and the result is either a very high magnitude positive or negative value. While it may be reasonable that avoided costs are more significant when circuits are on the threshold of being overloaded, it is not necessarily appropriate that the difference between the forecasted capacity of load-reducing and load-increasing DERs systemwide would impact that.

The 2024 ACC update addresses these concerns by calculating total deferral value independently for circuits which are forecasted to experience a net reduction in load from DERs vs. those which are forecasted to experience a net increase in load from DERs. The results from these two separate calculations are then averaged to arrive at a single value. This average is inherently weighted by the capacity of each type of DER installed. This approach minimizes the risk of arriving at an arbitrarily negative avoided cost value or one that is overly influenced by the forecasted difference between load-reducing and load-increasing DERs.

Both refinements described align with the broader methodological approach of the T&D White Paper and June 2019 ruling, which was reaffirmed to be used in the 2024 ACC update. These updates follow that prescribed approach with greater accuracy while accommodating the updated data and developments in systemwide DER growth patterns.

7.3 Use of Short-term and Long-term Avoided Distribution Costs

As stated in the T&D White Paper, “the impact of DERs to defer distribution upgrades accrue over the long term, while the GNA is limited to the forecast horizon that is necessary for distribution planning.” The avoided costs estimates discussed above are based on DDOR and GNA filings that use a five-year planning horizon. To extrapolate these estimates into long-term forecasts, the avoided costs in years one through five would be the unspecified deferral values held constant on a real dollar basis. Years eight and beyond would be the GRC level held constant on a real dollar basis. Years six and seven would linearly transition between the two end points of years five and eight. This method is depicted in Figure 7-2.

Figure 7-2. Illustrative Distribution Avoided Cost Transition

7.4 Long-term GRC-based Marginal Costs

The California IOUs have used a wide variety of methods for estimating distribution marginal costs in their GRC filings.[29] The long-standing purpose of the marginal costs in a GRC filing is to guide the allocation of the utility revenue requirement to customer classes and the design of marginal cost-based rates. The GRC filing therefore provides a useful source for marginal costs that are estimated on an approximate three-year cycle. However, the GRC marginal costs might not be completely appropriate for use in DER cost effectiveness evaluations. As with the values calculated for near-term marginal costs, GRC marginal costs are not location-specific and can include cost categories that are not necessarily avoidable. Therefore, Staff recommends that the GRC values be the source for long-run marginal costs, with the recognition that they may need to be modified for DER cost effectiveness and the ACC. No new GRC Phase IIs have been approved between the timing of the 2022 ACC update and the 2024 ACC update, so values for each utility remain the same, excepting the simple escalation of long-term cost results.

The values are presented in 2023$ in Table 7-2~~Table~~.

Table 7-2. Long-term Distribution Marginal Costs

Utility Climate Zone	PG&E (simple Average)	SCE All	SDG&E All
Long Term Distribution Capacity Cost ($/kW-yr.)	$ 57.29	$ 189.53	$ 89.51

[29] Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, Prepared for the CPUC, October 2004, p. 102

7.4.1 GRC Data Hierarchy

In selecting data to use for the long term avoided costs, Staff used the following hierarchy of GRC Phase II data sources, presented in descending order of preference.

1. Values adopted for revenue allocation from most recently completed proceeding.
2. Values adopted for rate design purposes from most recently completed proceeding.
3. Values agreed to by majority of parties for revenue allocation in settlement agreement from most recently completed proceeding.
4. Values agreed to by majority of parties for rate design purposes in settlement agreement from most recently completed proceeding.
5. Utility-proposed values for revenue allocation from most recently completed proceeding.

7.4.2 Distribution Marginal Costs from Most Recently Completed Proceedings

7.4.2.1 PG&E

PG&E provided updated marginal distribution capacity costs for the 2022 ACC, adopted in Decision 21-11-016.[30] PG&E confirmed that these values remain valid and the most appropriate data for use in the 2024 ACC update. Data is expressed in $/PCAF-kW-yr. and $/FLT-kW-yr. PCAF (Peak Capacity Allocations Factors) are hourly allocation factors used by PG&E to calculate the relative need for distribution capacity across the year. The PCAF-KW are the PCAF-weighted coincident peak demands on primary capacity equipment. The FLT-kW are the peaks on the final line transformers and represent a more noncoincident measure of peak demand on the secondary equipment. To make the two marginal costs compatible, secondary costs are converted from $/FLT-kW-yr. to $/PCAF-kW-yr. based on the ratio of FLT-kW to PCAF-kW in the division. The PCAF and FLT Loads used for converting secondary cost to $/PCAF-KW-YR and weighting climate zones come from PG&E's settlement agreement in the utility's 2017 Phase II General Rate Case (GRC) proceeding. These latter values and the source data were previously outlined in the 2021 ACC and are re-used for consistent weighting. Table shows the inputs and calculations for this process.

[30] DECISION ADOPTING MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGNS FOR PACIFIC GAS AND ELECTRIC https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M424/K378/424378035.PDF

Table 7-3. Long-Term Distribution Capacity Costs for PG&E by Division (Base Year of 2021)

		[A]	[B]	[C]	[D]	[E]	[F]
Division	Climate Zone	Primary Projects Total $/PCAF-KW-YR	Secondary Distribution $/FLT-KW-YR	Total PCAF Loads PCAF kW	Total FLT Loads FLT kW	Secondary Cost [B*D/C] $/PCAF-KW-YR	Total Distribution Capacity Cost [A+E] $/PCAF-KW-YR
CENTRAL COAST	4	$42.51	$1.66	823,510	1,759,256	$3.54	$46.05
DE ANZA	4	$44.84	$2.20	741,675	1,234,311	$3.66	$48.51
DIABLO	12	$69.63	$2.68	1,265,169	1,524,487	$3.22	$72.85
EAST BAY	3A	$40.86	$1.84	627,862	1,338,170	$3.92	$44.78
FRESNO	13	$48.47	$2.01	2,164,629	3,575,125	$3.31	$51.78
HUMBOLDT	1	$43.54	$1.40	292,803	736,437	$3.53	$47.06
KERN	13	$51.00	$2.20	1,585,454	2,449,767	$3.40	$54.40
LOS PADRES	5	$63.38	$1.82	492,381	1,041,742	$3.85	$67.22
MISSION	3B	$43.83	$2.23	1,233,354	2,022,915	$3.65	$47.48
NORTH BAY	2	$52.95	$2.06	647,540	1,283,383	$4.08	$57.03
NORTH VALLEY	16	$63.36	$1.73	742,213	1,324,624	$3.08	$66.44
PENINSULA	3A	$48.18	$2.02	766,475	1,436,434	$3.78	$51.96
SACRAMENTO	11	$46.65	$2.23	970,943	1,589,591	$3.66	$50.30
SAN FRANCISCO	3A	$48.93	$2.36	829,544	1,435,075	$4.08	$53.01
SAN JOSE	4	$46.29	$2.45	1,369,868	2,130,431	$3.81	$50.10
SIERRA	11	$43.89	$1.88	1,187,910	1,833,534	$2.90	$46.79
SONOMA	2	$43.15	$1.84	544,454	1,147,401	$3.87	$47.01
STOCKTON	12	$44.06	$1.99	1,207,506	2,114,747	$3.48	$47.54
YOSEMITE	13	$67.14	$1.85	1,090,280	2,098,437	$3.56	$70.70

Columns A and B provided as updated values by PG&E for the 2022 ACC

Columns C and D from PG&E 2017 GRC Phase II to maintain same climate zone weighting as the 2021 ACC

Finally, the division-level avoided costs are converted into climate zone values. If a climate zone encompasses more than one Operating Division, then the weighted average value is calculated using the 2017 PCAF kW in each Operating Division. The PG&E long-term distribution marginal capacity costs by climate zone are summarized below. Climate Zone 3A is the western portion of Climate Zone 3, comprised of San Francisco and neighboring cities in the Bay Area, while Climate Zone 3B represents the remainder of Climate Zone 3.

Table 7-4. Long-Term Distribution Capacity Costs for PG&E by Climate Zone (Base Year of 2021)

Climate Zone	Weighted Avg Capacity cost (F weighted by C) YR
1	**47.06**
2	**52.46**
3A	**50.32**
3B	**47.48**
4	**48.56**
5	**67.22**
11	**48.37**
12	**60.49**
13	**56.90**
16	**66.44**

Climate zone map from PG&E website (now moved)

7.4.2.2 SCE

SCE's long-term distribution marginal capacity costs have not been updated since the 2022 ACC update and are drawn from the utility's 2021 GRC Phase II proceeding.[31] SCE did not develop marginal costs on a geographically disaggregated basis, but used a regression analysis of cumulative distribution capacity-related investments and cumulative peak loads, consistent with avoided distribution capacity costs that have been used for SCE in prior avoided cost updates. As noted in prior ACCs, SCE had developed marginal costs for three categories of distribution capacity investment: subtransmission, substations, and local distribution. In the 2021 GRC, these values were broken out into four components, with each substation and local circuit costs provided for each Distribution and Subtransmission. These are each provided in the table below, drawn from table I-11 in the 2021 GRC Phase II.

[31] Table I-11 of SCE 2021 GRC Phase II testimony

Table 7-5. Long-term Distribution Marginal Capacity Costs for SCE ($2021)

	SCE Distribution Marginal Capacity Costs (2021$)	
	Substation	Circuit
Subtransmission ($/kW-yr)	$24.60	$16.40
Distribution ($/kW-yr)	$30.60	$109.40
Total ($/kW-yr)	$181.00	

7.4.2.3 SDG&E

SDG&E's long-term distribution marginal costs also remain consistent with those used in the 2022 ACC update. These are drawn from its 2019 GRC Phase II, which was adopted just prior to the 2022 ACC. These marginal costs are noted below.

Table 7-6. Long-term Distribution Capacity Costs for SDG&E[32]

	SDG&E Marginal Capacity Cost ($2019)
Substation ($/kW-yr)	$25.06
Local Distribution ($/kW-yr)	$57.63
Total	$82.69

7.5 Annual Distribution Capacity Costs

As discussed in section *7.3 Use of Short-term and Long-term Avoided* Distribution Costs~~*Use of Short-term and Long-term Avoided* Distribution Costs~~, the annual distribution marginal cost stream is a combination of near-term and long-term costs. The nominal marginal costs are shown below based on the UTILITY-specific escalation rates shown below. These escalations rates are also maintained from the 2022 ACC update, consistent with the last update applied for the GRC Phase II inputs.

Table 7-7. Distribution Annual Escalation Rates

	PG&E	SCE	SDG&E
Annual Distribution Escalation Rate (%/yr)	2.5%	2.33%	2.0%

Escalation rates are from the UTILITY RECC factor derivations for distribution capital projects.

[32] "CH_5_WP#4 Marg Dist Demand Costs Rebuttal" - and from SDG&E 2019 GRC Phase II

Table 7-8. Annual Distribution Marginal Capacity Costs ($/kW-yr) (Nominal)

		PG&E										SCE	SDG&E
	Climate Zone:	CZ1	CZ2	CZ3A	CZ3B	CZ4	CZ5	CZ11	CZ12	CZ13	CZ16	All	All
2023	Historical	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$3.34	$2.38
2024	Near Term	$1.58	$1.58	$1.58	$1.58	$1.58	$1.58	$1.58	$1.58	$1.58	$1.58	$3.41	$2.43
2025	Near Term	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$3.49	$2.47
2026	Near Term	$1.66	$1.66	$1.66	$1.66	$1.66	$1.66	$1.66	$1.66	$1.66	$1.66	$3.58	$2.52
2027	Near Term	$1.71	$1.71	$1.71	$1.71	$1.71	$1.71	$1.71	$1.71	$1.71	$1.71	$3.66	$2.57
2028	Near Term	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$3.74	$2.63
2029	Transition	$21.25	$23.55	$22.64	$21.43	$21.89	$29.85	$21.80	$26.98	$25.44	$29.51	$78.46	$36.71
2030	Transition	$40.75	$45.35	$43.53	$41.10	$42.02	$57.95	$41.86	$52.21	$49.14	$57.28	$153.17	$70.79
2031	Long Term	$60.24	$67.15	$64.42	$60.78	$62.16	$86.05	$61.91	$77.44	$72.84	$85.05	$227.88	$104.87
2032	Long Term	$61.75	$68.83	$66.03	$62.30	$63.72	$88.20	$63.46	$79.37	$74.66	$87.17	$233.19	$106.97
2033	Long Term	$63.29	$70.55	$67.68	$63.86	$65.31	$90.41	$65.05	$81.36	$76.53	$89.35	$238.62	$109.11
2034	Long Term	$64.88	$72.31	$69.37	$65.45	$66.94	$92.67	$66.67	$83.39	$78.44	$91.59	$244.18	$111.29
2035	Long Term	$66.50	$74.12	$71.11	$67.09	$68.61	$94.99	$68.34	$85.48	$80.40	$93.88	$249.87	$113.52
2036	Long Term	$68.16	$75.97	$72.88	$68.77	$70.33	$97.36	$70.05	$87.61	$82.41	$96.22	$255.70	$115.79
2037	Long Term	$69.87	$77.87	$74.71	$70.49	$72.09	$99.80	$71.80	$89.80	$84.47	$98.63	$261.65	$118.10
2038	Long Term	$71.61	$79.82	$76.57	$72.25	$73.89	$102.29	$73.60	$92.05	$86.58	$101.10	$267.75	$120.46
2039	Long Term	$73.40	$81.81	$78.49	$74.05	$75.74	$104.85	$75.44	$94.35	$88.75	$103.62	$273.99	$122.87
2040	Long Term	$75.24	$83.86	$80.45	$75.91	$77.63	$107.47	$77.32	$96.71	$90.96	$106.21	$280.37	$125.33
2041	Long Term	$77.12	$85.96	$82.46	$77.80	$79.57	$110.16	$79.26	$99.13	$93.24	$108.87	$286.90	$127.84
2042	Long Term	$79.05	$88.11	$84.52	$79.75	$81.56	$112.91	$81.24	$101.61	$95.57	$111.59	$293.59	$130.39
2043	Long Term	$81.02	$90.31	$86.64	$81.74	$83.60	$115.73	$83.27	$104.15	$97.96	$114.38	$300.43	$133.00
2044	Long Term	$83.05	$92.57	$88.80	$83.79	$85.69	$118.63	$85.35	$106.75	$100.41	$117.24	$307.43	$135.66
2045	Long Term	$85.12	$94.88	$91.02	$85.88	$87.83	$121.59	$87.48	$109.42	$102.92	$120.17	$314.59	$138.37
2046	Long Term	$87.25	$97.25	$93.30	$88.03	$90.03	$124.63	$89.67	$112.15	$105.49	$123.18	$321.92	$141.14
2047	Long Term	$89.43	$99.68	$95.63	$90.23	$92.28	$127.75	$91.91	$114.96	$108.13	$126.25	$329.42	$143.97
2048	Long Term	$91.67	$102.18	$98.02	$92.48	$94.59	$130.94	$94.21	$117.83	$110.83	$129.41	$337.10	$146.84
2049	Long Term	$93.96	$104.73	$100.47	$94.80	$96.95	$134.21	$96.56	$120.78	$113.60	$132.65	$344.95	$149.78
2050	Long Term	$96.31	$107.35	$102.98	$97.17	$99.37	$137.57	$98.98	$123.80	$116.44	$135.96	$352.99	$152.78
2051	Long Term	$98.72	$110.03	$105.56	$99.59	$101.86	$141.01	$101.45	$126.89	$119.35	$139.36	$361.22	$155.83
2052	Long Term	$101.19	$112.78	$108.20	$102.08	$104.40	$144.53	$103.99	$130.06	$122.34	$142.85	$369.63	$158.95
2053	Long Term	$103.72	$115.60	$110.90	$104.64	$107.02	$148.15	$106.59	$133.31	$125.40	$146.42	$378.25	$162.13
2054	Long Term	$106.31	$118.49	$113.68	$107.25	$109.69	$151.85	$109.25	$136.65	$128.53	$150.08	$387.06	$165.37

7.6 Allocation of Avoided Distribution Capacity Costs to Hours

The annual capacity costs shown above are allocated to hours of the year to allow the ACC to reflect the time varying need for distribution capacity. Earlier ACCs used the distribution hourly allocation factors based on regression estimates of distribution hourly loads. Those estimates reflected forecasts of net loads (load net of local PV production) for the present and future (2030). In this way, the allocation factors estimated an evolution in the timing of the peak capacity needs on the distribution system due to DER. With the change to estimating distribution capacity costs under the paradigm of no new incremental DER, this estimation of the timing of peak capacity needs in a future with more DER is no longer needed. Therefore, the distribution hourly allocation factors estimated for 2024 are used for all years (2024 – 2054) in the ACC.

In addition to holding the allocation factors fixed over the analysis period, this ACC update also utilizes historical utility data and GRC analyses for the allocation factors. Details by IOU are provided in Appendix 12.4.1.

7.6.1 Distribution Day and Weather Mapping

The distribution capacity hourly allocation factors described above reflect the particular years from which the historical data was obtained. The peak loads are therefore driven by weather conditions in those years

– and that weather will not match the CTZ22 weather files used for the generation avoided cost modeling. To better align the distribution and generation costs, the distribution allocation factors are reordered to align with the weather in the CTZ22 files. Moreover, the hourly allocation factors are realigned so that the occurrence of weekends and holidays, as well as daylight-savings time matches a 2018 calendar year.[33] This remapping of allocation factors for weekends vs. workdays is particularly important for the evaluation of energy efficiency measures that vary by occupation schedules such as office HVAC.

For the 2024 ACC update, PG&E's distribution PCAF values and SCE's PLRF values remain unchanged from the 2022 ACC update, as they are tied to each utility's GRC Phase II update cycle. SDG&E does not generate PCAFs or PLRFs, and so provided distribution-level power flow data for each of its climate zones in the 2023 year. Using this data, the consultant calculated allocation factors following the methodology detailed in Appendix 12.4.1. 2023 temperature data comes from the National Oceanic and Atmospheric Administration database for weather stations within SDG&E's service territory and is mapped to climate zones using the index provided in the CEC *California Climate Zone* tool.[34] Because 2023 data for climate zone 6 had significant data quality issues and missing values, temperature data for climate zone 9 was used to approximate climate zone 6. This proxy climate zone was selected both based on geographic proximity and the observed alignment of heating and cooling days between climate zones 9 and 6.

Table 7-9. Weather stations corresponding to climate zones

Climate Zone	Weather Station
CZ 1	Arcata
CZ 2	Santa Rosa
CZ 3	Oakland
CZ 4	San Jose
CZ 5	Santa Maria
CZ 6	Torrance
CZ 7	San Diego-Lindbergh
CZ 8	Fullerton
CZ 9	Burbank-Glendale
CZ 10	Riverside
CZ 11	Red Bluff
CZ 12	Sacramento
CZ 13	Fresno
CZ 14	Palmdale
CZ 15	Palm Spring-Intl
CZ 16	Blue Canyon

All timeseries data are assigned in 24-hour days to bins by workday/weekend-holiday, and season. Within each bin, the timeseries data is ranked by a temperature metric for each day. The temperature metric used for the PCAF is the mean temperature over the course of a day. The remapping then reorders the timeseries

[33] The 2018 calendar year starts on a Monday and aligns with the 2024 calendar year except in that it does not include a leap day.

[34] https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards/climate-zone-tool-maps-and

data by day within each bin by mapping temperature metric ranks for the master data and the weather data used in the utility analyses. For example, PCAFs for the summer weekday with the highest temperature metric (mean average temperature) will be remapped to the CTZ22 weekday with the highest ranked temperature metric. The second highest PCAF day would be mapped to the second highest base day, etc. If there are more source days in the bin than base year days, the lowest ranked source days would be discarded. If there are fewer source days in the bin than base year days, the lowest ranked source day would be replicated as needed. Given that PCAF and PLRF are concentrated in relatively few hours of the year, the effects of duplicating or discarding the lowest ranked days would likely have no impact.

The remapping process results in distribution hourly allocation factors that sum to the same total of 100% for each climate zone, but better reflect the expected impact of CTZ22 weather and align all weekends and holidays with a 2018 calendar year.

8 Transmission and Distribution Loss Factors

8.1 T&D Capacity Loss Factors

The value of deferring transmission and distribution investments is adjusted for losses during the peak period using the factors shown in Table and

Table

~~Table~~ . These factors are lower than the energy and generation capacity loss factors because they represent losses only from the secondary meter to the distribution or transmission facilities. These values remain the same from the 2022 ACC.

Table 8-1. Loss Factors for SCE and SDG&E Transmission and Distribution Capacity

	SCE	SDG&E
Distribution	1.022	1.043
Transmission	1.054	1.071

Table 8-2. Loss Factors for PG&E Transmission and Distribution Capacity

	Transmission	Distribution
Central Coast	1.053	1.019
De Anza	1.050	1.019
Diablo	1.045	1.020
East Bay	1.042	1.020
Fresno	1.076	1.020
Kern	1.065	1.023
Los Padres	1.060	1.019
Mission	1.047	1.019
North Bay	1.053	1.019
North Coast	1.060	1.019
North Valley	1.073	1.021
Peninsula	1.050	1.019
Sacramento	1.052	1.019
San Francisco	1.045	1.020
San Jose	1.052	1.018
Sierra	1.054	1.020
Stockton	1.066	1.019
Yosemite	1.067	1.019

9 High GWP Gases

9.1 Introduction

This avoided cost component, introduced in 2020, measures the greenhouse gas (GHG) emissions from methane, a type of high Global Warming Potential (GWP) gases. High GWP gases are defined as GHGs that have a greater impact on global warming than CO_2. The GWP of a given gas is the ratio of its atmospheric effect on global warming to that of CO_2, so that the larger the GWP the more that a given gas contributes to the atmospheric greenhouse effect over a given time period. The GWP of a given gas may differ depending on the time period over which it is measured. For example, methane has a GWP of 72 over 20 years and a GWP of 25 over 100 years.[35] The 100-year GWP is used by CARB for emission inventory calculations and is provided as the default value with the 20-year GWP is provided as a sensitivity.[36]

[35] The 100-year GWP is used the CARB inventory, documented here. The 20-year GWP is documented in IPCC materials, for example the technical documentation for the IPCC Fourth Assessment Report, p. 212.

[36] See CARB Global Warming Potentials Table, available at: https://ww2.arb.ca.gov/ghg-gwps

The impetus for this component was primarily the advent of DER programs designed to replace natural gas appliances with electric appliances, due to recent changes in state energy policy and new legislation.[37] These programs *decrease* GHG emissions due to their reduction in natural gas usage and associated methane leakage, but they simultaneously *increase* GHG emissions due to their increase in electricity consumption. Therefore, these changes must be accounted for to accurately measure the GHG impact of these new programs. This avoided cost is used to value changes in methane leakage for a wide range of DERs, since DER programs are generally designed to decrease electricity consumption (which then results in a decrease in natural gas usage at power plants) or to decrease direct natural gas consumption in buildings.

Methane leakage occurs within the natural gas system, so decreases in natural gas consumption can result in decreases in methane leakage, although the exact relationship between usage and leakage in different parts of the system is unclear. However, in the long run, large scale electrification will decrease methane leakage as large sections of the natural gas infrastructure are shut down. This avoided cost component estimates this effect.

9.2 Methane

9.2.1 Introduction and summary

Natural gas is the primary fuel used in buildings both indirectly, for electricity generation, and directly, for space and water heating, cooking, and clothes drying. Natural gas consists mostly of methane. When methane is combusted, it produces CO_2, whereas if it leaks before it can be combusted it is not only wasted as a fuel but also has a disproportionately high impact on global warming, as compared to burning that same methane. Uncombusted methane has a 100-year GWP of 25, meaning it is 25 times more potent than CO2 as a greenhouse gas over a 100-year time horizon. Over a shorter time horizon, uncombusted methane is even more potent, which is why methane has a 20-year GWP of 72. The 100-year values are primarily what is discussed in this documentation, as this is what is used in the ARB GHG inventory, although the ACC includes the option to toggle between 100-year and 20-year GWPs. The 100-year value is the default value used in the ACC, with the 20-year value included for sensitivity analysis purposes.

Methane leakage occurs in all parts of the natural gas system – at production and storage facilities, in pipelines, at the meter, and behind the meter. The link between natural gas use (throughput) and methane leakage is not precisely known. Decreases in natural gas usage may result in decreased leakage at production facilities, since fewer new wells will be drilled over time in response to decreased demand (and old wells may be taken out of service), but may not result in decreased leakage within pipelines or at storage facilities, at least in the short run, because many of those systems are kept at a constant pressure. However, in the long run, as parts of the natural gas distribution system are shut down as the result of building decarbonization efforts, methane leakage in the entire system will decrease.[38] Likewise, building

[37] Such as SB1477 and AB3232, which implement statewide building decarbonization efforts.

[38] As identified in the 2018 CARB/CPUC Joint Staff Report analyzing the California natural gas utilities' leakage abatement reports, leakage in the natural gas distribution system and at the meter represents the majority (roughly 70%) of in-state T&D leakage. Therefore, the majority of methane leakage in the T&D system could be avoided through large-scale building electrification that would allow a coordinated retirement of the gas distribution system.

decarbonization will eliminate leakage at the meter, and behind the meter, particularly when all natural gas appliances are removed from a building and the building's gas connection is shut off.

Two options were considered for an avoided methane leakage rate: a national average estimate of 2.4% from a 2018 study and an in-state estimate of 0.7% implied by the CARB inventory.[39] Since California imports more than 90% of its natural gas, a national average, as opposed to a statewide estimate for methane leakage, is more appropriate for determining the lifecycle leakage of natural gas consumed in California. However, out-of-state methane leakage is not included in the CARB inventory, meaning that reducing this leakage does not count towards achieving California's GHG reduction goals. Thus, reduced out-of-state methane leakage is not strictly an avoided cost to California ratepayers, as defined by the current avoided cost framework. Therefore, the ACC uses the in-state estimate of 0.7% implied by the CARB inventory. However, out-of-state methane leakage could, in theory, be incorporated as a societal cost, paired with a societal carbon price, in a future societal cost-effectiveness test.

The 0.7% estimate is a methane leakage *rate*, which is simply the percent of California natural gas consumption that is assumed to leak within the state. For incorporation into avoided costs, a leakage *rate* must be converted to a leakage *adder*—the % increase that methane leakage *adds* to the GHG intensity of natural gas. A 0.7% leakage rate is equivalent to a 6.4% leakage adder, due to the high GWP of methane. In this document, the consultant primarily uses leakage adders to quantify methane leakage as they are the most directly applicable to values.

In 2020, CPUC Energy Division staff and its consultant coordinated with CARB to discuss the proposed 6.4% leakage adder (originally proposed as an equivalent 0.7% leakage rate) and determine if it is an appropriate value. CARB informed us that the previous estimate of 6.4% included all sources of methane leakage in the state, including behind-the-meter leakage. The consultant re-visited the inventory to develop separate estimates for upstream and behind-the-meter, so that methane leakage can be properly attributed to each category of natural gas use examined in the ACC. The resulting estimates are a leakage adder of 5.57% for upstream in-state methane leakage and a leakage adder of 3.78% for residential behind the meter leakage.

The leakage adder is the percent of CO_{2e} emissions that will be added to gas emissions estimates in the ACC to account for methane leakage, which will be applied to all DERs. The residential behind-the-meter leakage adder will be applied only to DERs that reduce behind-the-meter natural gas combustion through removal of natural gas appliances.

The upstream leakage adder of 5.57% is most accurately described as an estimate of "long-run avoided methane leakage" for the natural gas system. With the exception of methane leakage at the individual appliance level, it is unclear if methane leakage in the natural gas system in California will change as a function of throughput,[40] unless portions of the gas distribution system are shut down due to coordinated electrification. However, in the long run, as the state transitions away from using natural gas in buildings,

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[39] October 2019 IDER Staff Proposal. Note that the in-state 0.7% estimate is a rate of leakage occurring within state borders, expressed as a percentage of total natural gas consumption in the state, most of which is imported. Thus, the leakage rate for CA-produced natural gas alone would be much higher.

[40] While decreased natural gas usage is likely to result in decreased methane leakage at production facilities, since less natural gas will be pumped, most of that leakage is not considered here because California imports almost all of its natural gas.

most or all of the leakage in the natural gas system in the state could be avoided. Thus, it makes the most sense to attribute avoided methane leakage proportionally to each natural gas reduction, and each removed natural gas appliance, rather than only to the last building to electrify that enables part of the gas system to shut down. In other words, reducing natural gas usage will lead, in the long run, to reduced methane leakage that is likely to occur in a stepwise fashion, where large cumulative reductions in natural gas usage result in reductions in leakage that occur in relatively large "steps." By applying that large, long-run reduction to each BTU of natural gas reduction, the stepwise function is "smoothed out", and spreading the same total reduction in GHGs more evenly over time. This is similar to the way the ACC currently treats avoided generation capacity, where even a small change in peak energy usage is considered to have capacity value, even though only relatively large changes will actually avoid the construction of a new power plant.

9.2.2 Detailed Methodology for Methane Leakage Adders

The leakage adders in the 2022 ACC are calculated using CO2-equivalent emissions numbers from the 2017 GHG inventory published by the ARB.[41] The ARB inventory is a record of all GHG emissions occurring within the state borders of California, plus any out-of-state GHG emissions from electric generators supplying electricity to California.

As mentioned in the preceding section, the methane leakage rate originally proposed in the IDER Staff Proposal was 0.7%, which corresponds to a 6.4% leakage adder (further explanation of the difference between these two quantities is below). After coordination with ARB, this estimate was refined to break out the residential behind-the-meter component of methane leakage, and divide this by residential consumption only, to arrive at the residential behind the meter leakage adder.

There are three categories of methane leakage that are included in the ARB inventory: 1) Oil & Gas Production and Processing, 2) Natural Gas Transmission and Distribution, and 3) Residential Behind-the-Meter (BTM). The methane leakage in categories 1) and 2) reflects the "upstream" methane leakage occurring within state boundaries and is thus assumed to apply to all natural gas consumed in California. The CO2-equivalent methane leakage in these categories is divided by the CO2 emissions from all natural gas consumption in California, to arrive at the **upstream in-state methane leakage adder** of 5.57%. Note that the methane leakage emissions from production and processing of natural gas imported to California from out-of-state (representing about 90-95% of natural gas consumption in California) are not included in this estimate, so this 5.57% is significantly lower than it would otherwise be if these out-of-state emissions were included. These out-of-state emissions are not currently in the ARB inventory, which is why they are not currently included in this upstream emissions estimate. Also note that the CO2-equivalent methane leakage included in the ARB inventory is calculated using the 100-year GWP for methane.

Similarly, the **residential behind-the-meter leakage adder** of 3.78% is calculated by dividing the CO2-equivalent methane leakage emissions in category 3) above by the CO2 emissions from residential natural gas consumption only. This second adder applies only to natural gas consumed in residential buildings and is included as an avoided cost only for programs which remove a natural gas appliance from a building, since more efficient gas appliances such as tankless water heaters are not likely to reduce methane leakage.

These **methane leakage adders** are distinct from **methane leakage rates**, which were what was originally described in the Staff Proposal. Methane leakage rates reflect the percentage of unburned natural gas that is leaked across the lifecycle of natural gas consumption. Methane leakage adders reflect the impact of this leaked natural gas on the GHG intensity of natural gas, which is what is required for incorporating methane leakage into avoided cost calculations. A leakage adder is higher than its corresponding leakage rate due to the high GWP of methane. These two values are calculated in the following way:

- Methane leakage rate = $\frac{mass\ of\ natural\ gas\ leaked}{mass\ of\ natural\ gas\ consumed}$
  - Answers the question: "What percent of my natural gas supply was leaked?"

[41] The 2017 ARB inventory (Economic Sector categorization) can be found here: https://ww3.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_by_sector_all_00-17.xlsx . This is the most recent version of the inventory.

- Methane leakage adder = $\frac{CO2\text{−}equivalent\ emissions\ from\ leaked\ natural\ gas}{CO2\ emissions\ from\ burned\ natural\ gas}$
    - Answers the question: “How does this leaked methane increase the overall GHG emissions from natural gas consumption?”

At first glance, one might guess that the leakage adder is simply equal to the leakage rate times the GWP of methane, equal to 25 over a 100-year time horizon. However, this is not the case, because methane actually *gains mass when it is burned* due to being oxidized with oxygen-- each tonne of methane yields 2.74 tonnes of CO2 when it is burned. Thus, the conversion from a methane leakage rate to a methane leakage adder is done in the following way:

methane leakage rate

methane leakage adder

$$\boxed{\frac{mass\ of\ methane\ leaked\ (tonnes\ CH4)}{mass\ of\ methane\ consumed\ (tonnes\ CH4)}} \quad \begin{matrix} \longrightarrow * \dfrac{25\ tonnes\ CO2eq}{tonne\ CH4\ leaked} \longrightarrow \\ \\ \longrightarrow * \dfrac{2.74\ tonnes\ CO2}{tonne\ CH4\ burned} \longrightarrow \end{matrix} \quad = \quad \boxed{\frac{CO2eq\ emissions\ from\ leaked\ NG}{CO2\ emissions\ from\ burned\ NG}}$$

And therefore, because 25/2.74 = 9.1:

$$methane\ leakage\ rate \quad * \quad 9.1 \quad = \quad methane\ leakage\ adder$$

Thus, the conversion factor between a methane leakage rate and a methane leakage adder is actually 9.1, not 25.[42]

Another way of looking at this is that on a tonne-by-tonne basis, methane does have 25 times the impact of CO2. In other words, releasing a tonne of methane to the atmosphere has 25 times the global warming impact of releasing a tonne of CO2 to the atmosphere (over 100 years). However, we are not comparing methane to CO2 on a tonne-by-tonne basis. Rather, we are comparing methane leakage to CO2 combustion. In other words, we are comparing tonnes of natural gas that we intended to combust but accidentally leaked instead with tonnes of natural gas that we are burning for fuel and thus producing CO2 as a byproduct.

For example, we start out with a tonne of methane. If we leak it, then a tonne of methane will enter the atmosphere, which will have 25 times the global warming impact of a tonne of CO2. But, if we burn it, because of the different molecular mass of CH4 (methane) and CO2, more than 1 tonne of CO2 will be

[42] Note that this calculation assumes, for explanation purposes, that natural gas is 100% methane. In reality natural gas is about 95% methane, so the conversion factor of 9.1 would have to be modified slightly to account for this. However, since the ACC only relies on the leakage adders, which are calculated directly from the ARB inventory and do not require the conversion factor of 9.1, it is not necessary to account for this adjustment for the purposes of developing methane leakage estimates for the ACC. The explanation of the 9.1 conversion factor is included only to clarify the difference between leakage rates and leakage adders, since the Staff Proposal included a discussion of leakage rates only.

produced. Burning a tonne of methane produces 2.74 tonnes of CO2. In order to determine the global warming impact of the leaked methane, we do not want to compare the effect of the leaked methane to that of one tonne of CO2, but rather to the 2.74 tonnes of CO2 we would have produced by burning it. So, we divide 25 by 2.74 to get 9.1. Hence, a tonne of methane leakage has 9.1 times the global warming impact if it is leaked compared to if it is burned.

The final methane leakage adders, and their corresponding leakage rates, are included in the table below. Also included are the leakage adder values that correspond to a 20-year GWP for methane, which is calculated by multiplying the 100-year leakage adders by 2.88, the ratio between the 20-year and 100-year GWPs for methane (72 and 25, respectively). A toggle to switch between these two GWP calculations is included in the ACC; although the primary adopted value is the 100-year leakage adder (middle column).

Table 9-1. Leakage Adders in the ACC and their Corresponding Leakage Rates

Leakage type	Leakage rate (% of natural gas consumption)	Leakage adder, 100-year GWP (% of CO2e emissions)	Leakage adder, 20-year GWP (% of CO2e emissions)
Upstream in-state methane leakage	0.612%	5.57%	16.04%
Residential behind-the-meter methane leakage	0.415%	3.78%	10.89%

9.3 Use Cases

This avoided cost component has three different parts, or use cases, which will apply to different types of measures and affect different parts of the ACC. The use cases are described below, and details of the equations used to calculate them are discussed in the subsequent section.

Use case #1: Changes in electricity usage – This use case would likely affect all traditional electric DER programs, since they almost always result in decreases in electricity usage. All electric energy efficiency measures (by definition), most demand response programs (except possibly some load shift demand response), and most customer generation programs, result in decreases in electricity use.[43]

Decreases in GHG emissions from electricity usage depend partially on the hours of the day and year the electricity reductions occur. For this reason, the value of GHG emissions is based on both hourly electricity reductions and the GHG intensity of the electric grid for that hour. For example, the GHG intensity of the grid is zero during any hour where the marginal generating unit is a solar resource.

[43] "Electricity use" in this sense refers only to utility-supplied electricity. A customer who generates their own electricity may increase or decrease their total usage, but their utility-supplied usage will decrease.

The value of avoided GHG of any particular DER in a given hour is calculated to be the product of the electric GHG adder, the GHG intensity of the grid during that hour, and the change in electricity usage. Additionally, the GHG adder reflects that reduced electricity usage results not only in reduced natural gas usage at the generator, but also reduced methane leakage in the natural gas system.

Use case #2: Changes in gas usage – This use case applies only to programs that change the amount of direct natural gas consumption in buildings. It affects all traditional gas EE measures, as well as building decarbonization efforts that result in the removal of natural gas appliances.

The value of avoided GHG of a gas EE measure is the reduced GHG emissions multiplied by the gas GHG value, where the reduced GHG emissions are simply the lifetime decrease in natural gas consumption of the device (or program) multiplied by a constant which reflects the carbon intensity of natural gas. Additionally, two terms reflect that reduced natural gas usage results in reduced upstream and behind-the-meter methane leakage. The upstream adder is applied to all programs which directly reduce natural gas consumption, but the behind-the-meter adder is applied only to programs that eliminate natural gas appliances from the building.

9.4 Use Case Equations

Details of the equation used to calculate each use case are shown below, and more information about each variable can be found in the table:

1. **Change in electricity usage for device *i***

This use case will apply to all DERs that result in changes in electricity usage. The new GHG value is the change in GHG emissions, multiplied by a percentage increase to account for methane leakage, and then multiplied by the electric model GHG adder. The change in GHG emissions, in tonnes of CO_{2e}, is the hourly carbon intensity of the electric grid multiplied by the hourly change in electricity usage, summed over all hours. The percentage increase due to methane leakage is 100% + the upstream methane adder ($\delta\%_{upstream}$), or 105.57%. Note that except for the addition of the upstream methane adder, this calculation is the same in the current value of GHG.

$$\text{Value of change in electricity usage} = \Sigma_h\left(CI_{grid,h}\,\Delta E_{h,i}\right) * \left(100\% + \delta\%_{upstream}\right) * P_{GHGe}$$

($)	=	(tonnes CO_{2e})	(dimensionless)	($\frac{\$}{tonne\ CO2e}$)

2. **Change in gas usage for device *i***

This use case will apply to all DERs that result in changes in direct natural gas usage in a building. The new GHG value is the change in GHG emissions multiplied by a percentage increase to account for methane leakage, and then multiplied by the natural gas GHG value. The first term in the equation below represents the change in GHG emissions, in tonnes of CO_{2e}, and it is equal to the carbon intensity of natural gas multiplied by the change in gas usage of a particular device (or program). The second term is the percentage increase due to methane leakage, which is 100% + the upstream methane adder ($\delta\%_{upstream}$) + the behind-the-meter adder ($\delta\%_{BTM}$). For programs that reduce natural gas consumption, but do not eliminate natural gas appliances from the building, the behind-the-meter adder is zero. Note that with the exception of addition of the terms $\delta\%_{upstream}$ and $\delta\%_{BTM}$ this calculation is the same as the current value of GHG for gas EE measures. Hence, for gas EE measures which reduce gas usage, the GHG value will be increased by 100% + the upstream methane adder, or 105.57%, as compared with the current GHG avoided cost[44]. For programs that eliminate natural gas appliances from the building, the current GHG value will be increased by 100% + the upstream methane adder + the behind-the-meter adder, or 100% +5.57% + 3.78% = 109.35%[45].

$$\text{Value of change in gas usage} = \left(CI_{gas}\,\Delta G_i\right) * \left(1 + \delta\%_{upstream} + \delta\%_{BTM}\right) * P_{GHGg}$$

$$(\$) \quad = \quad (\text{tonnes } CO_{2e}) \quad (\text{dimensionless}) \quad \left(\frac{\$}{tonne\ CO2e}\right)$$

10 Avoided Natural Gas Infrastructure Costs (AGIC)

New construction of all-electric buildings avoid investment in new natural gas distribution infrastructure. This avoided cost was previously adopted for Energy Efficiency programs[46], but will now apply to all distributed energy resource programs. This new avoided cost uses a similar method as in the Energy Efficiency proceeding and has been included in the 2022 ACC for use in cost-effectiveness evaluation of new construction building electrification projects and programs. The avoided gas infrastructure cost categories included in this calculation are mainline extensions, service extensions, and meters. The AGIC costs in the ACC currently exclude costs borne by the customer, such as in-house infrastructure and plan reviews, although it is expected that these avoided costs will be included in the cost-effectiveness analyses done in individual resource proceeding.

Avoided cost estimates for natural gas distribution investments that are avoided by all-electric new construction is developed from GRC filings or other marginal cost filings. This information is on a separate tab within the Avoided Cost Calculator and will not be included in the hourly marginal avoided costs. It must be added separately to the benefits used in cost-effectiveness tests, and only for new construction projects, measures, and programs that have this benefit. The AGIC costs per unit are provided by utility through data requests and included in Appendix 12.6.

11 Societal Cost Test (SCT)

The 2024 ACC also includes a Societal Cost Test (SCT) option in response to the Decision Adopting the Societal Cost Test mailed May 24, 2024 (R.22-11-013) for both Electric and Gas models. The SCT has four avoided cost streams that are different from the regular, Total Resource Cost (TRC) version of the ACC, as outlined in the following sections.

- **Social Cost of Carbon (SCC):** The SCT includes two values for a Social Cost of Carbon (SCC). These are the “Base” and “High” values and refer to the average and 95th percentile social cost of carbon

[44] This does not take into account any changes to the value of P_{GHGg}, the natural gas GHG value.

[45] This does not take into account any changes to the value of P_{GHGg}, the natural gas GHG value.

[46] Advice Letters 4386-G/6094-E and 4387-G/6095-E.

assuming a 3% real discount rate, as published by the Interagency Working Group on Social Cost of Greenhouse Gases[47] as summarized in Figure 11-1.

Figure 11-1. Social Cost of Carbon (2020$/metric ton of CO2)[47]

Emissions Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2020	14	51	76	152
2025	17	56	83	169
2030	19	62	89	187
2035	22	67	96	206
2040	25	73	103	225
2045	28	79	110	242
2050	32	85	116	260

- **Societal Discount Rate:** The SCT uses a societal discount rate of 5.06~~3~~% nominal (3% real) instead of the IOU WACC of 7.3%.
- **Methane Leakage Adder:** The SCT uses a national average methane leakage rate of 2.3% for up-stream methane leakage, compared to an in-state rate of 0.61% for the TRC. See discussion in Section 9.2.2 for details on the conversion of methane leakage ***rates*** to methane leakage ***adders***.
- **Air Quality Adder:** The SCT includes an additional component to account for the health impacts of gas combustion both on the electric system for power generation and in distributed applications. For both applications, the ACC uses air quality impacts estimated by the 2021 report "Quantifying the Air Quality Impacts of Decarbonization and Distributed Energy Programs in California" as summarized in Figure 11-2[48].

  In the Electric Model, the Air Quality Adder uses the value for gas generation of $1.75/MMBtu and calculates an hourly adder based on the hourly marginal emissions rate. In the Gas Model, the value for gas combustion in buildings of $1.23~~30~~/therm is applied directly as an avoided cost. The $1.23/therm evaluates "[d]irect emissions from energy sectors that contribute to air pollution include oxides of nitrogen (NOx), particulate matter (PM), carbon monoxide (CO), reactive organic gasses (ROG), and oxides of sulfur (SOx)." Since the Air Quality Adder already includes the impact of NOx emissions, the NOx emission is set to zero for SCT. We assume the full AQA ($1.23/therm)

[47] Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, Interagency Working Group on Social Cost of Greenhouse Gases, February 2021, https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[48] Quantifying the Air Quality Impacts of Decarbonization and Distributed Energy Programs in California, E3 and Advanced Power and Energy Program (APEP), 2021, https://www.ethree.com/wp-content/uploads/2022/01/CPUC-Air-Quality-Report-FINAL.pdf

applies to the appliance with the highest emission rates. For appliances with lower NOx emission rates, the AQA is scaled down proportionally. For example, an uncontrolled large boiler with a NOx emission rate of 0.019 lb/therm would have an AQA of $1.23 per therm. A low NOx burner large boiler with a NOx emission rate of 0.014 lb/therm (73% of the uncontrolled boiler's rate) would have an AQA of $0.91 per therm. This adjustment provides a proxy for varying AQA values based on appliance emission rates, given the lack of baseline emission rate data for the appliances that determine the AQA value.

Figure 11-2. Monetized human health air quality impacts ($2020)[48]

SECTOR	UNIT	$/UNIT	$/MMBTU
GAS GENERATION*	$/MWh	$ 14.00	$ 1.75
GAS COMBUSTION IN BUILDINGS	$/therm	$ 1.23	$ 12.30
ALL ON-ROAD VEHICLES	$/gge	$ 1.47	$ 10.97
LIGHT-DUTY VEHICLES	$/gge	$ 0.56-0.60	$ 4.18-4.48
MEDIUM-DUTY VEHICLES	$/gge	$ 2.77-3.14	$ 20.67-23.43
HEAVY-DUTY VEHICLES	$/gge	$ 4.20-4.52	$ 31.34-33.73

* for gas generation, the $/MMBtu is based on the quantity of natural gas consumed

In both the electric and gas avoided costs, the SCC is implemented as a floor on the total GHG value. In the electric avoided costs, the GHG value also reflects the cost of achieving the state's decarbonization targets. In the gas avoided costs, the GHG value reflects the cost of building electrification. These assumptions, which are used in the TRC version of the ACC, are also applied in the SCT version.

Finally, the electric avoided costs also account for the interaction between GHG and generation capacity avoided costs, as described in detail in Section 5. The total GHG and generation capacity value are recalculated while incorporating the SCC and Air Quality Adder values.

Total GHG avoided costs as well as generation capacity avoided costs for SCT are shown in the figure below. GHG avoided costs for SCT are higher than TRC. This is driven by two factors: In the near-term, GHG costs are set by a social cost of carbon that is higher than cap-and-trade price. In the long-term, a lower discount rate applied in the SCT calculations means that the financial impacts of reduced solar energy revenues and diminishing emission value in future years are less discounted, thereby increasing the GHG avoided costs. On the other hand, generation capacity value in the SCT are lower than TRC, highlighting the inter-dependence of the two values in covering resource costs.

Figure 11-3. Total GHG Avoided costs - SCT vs TRC

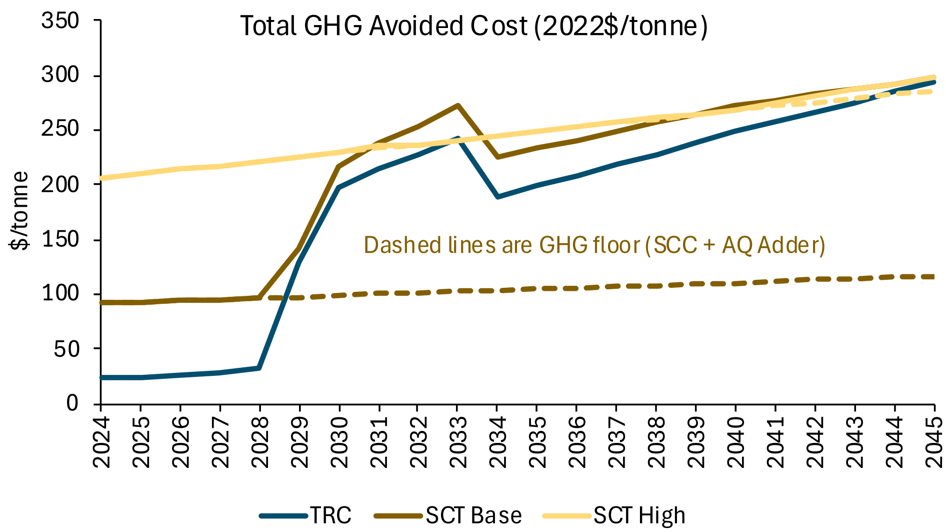
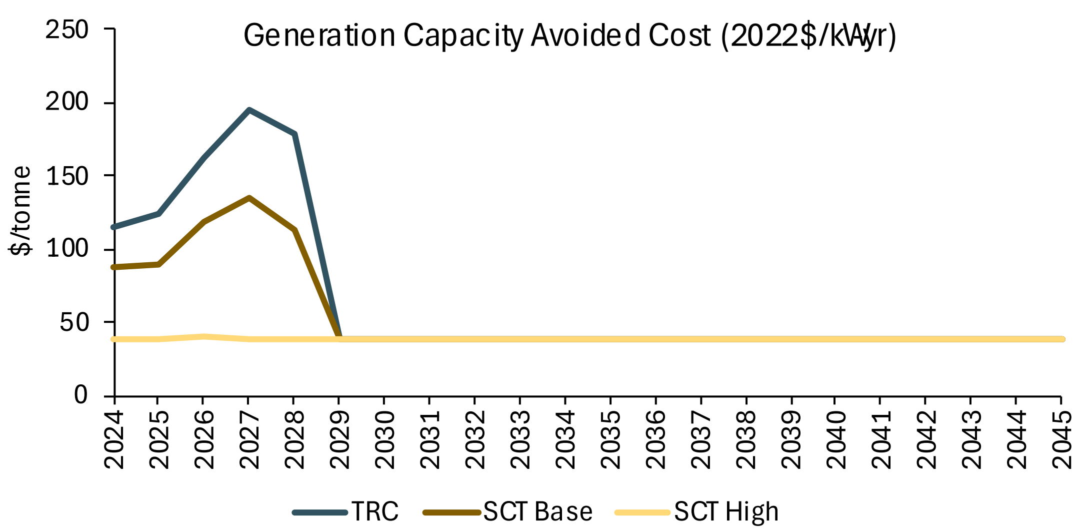


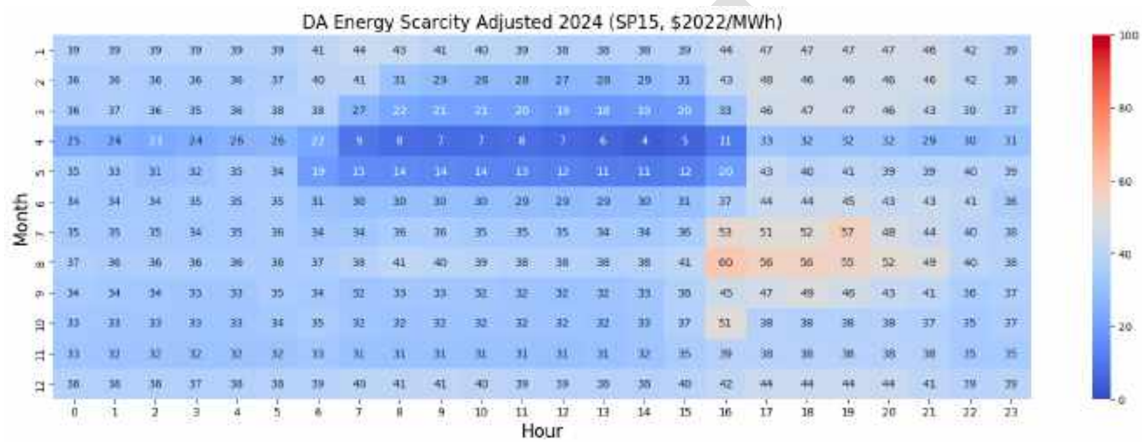
Figure 11-4. Generation Capacity Avoided Costs - SCT vs TRC



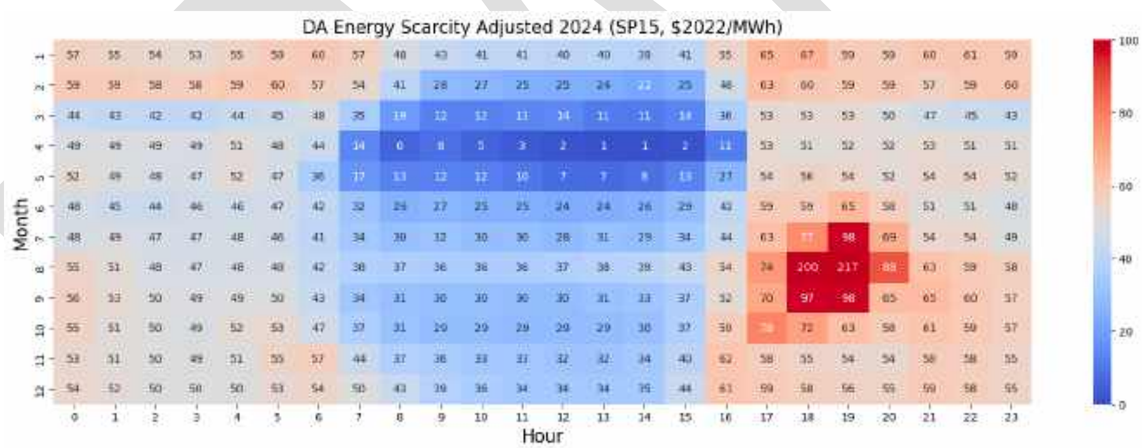
12 Appendix

12.1 Comparison of 2022 ACC and 2024 ACC SERVM Prices

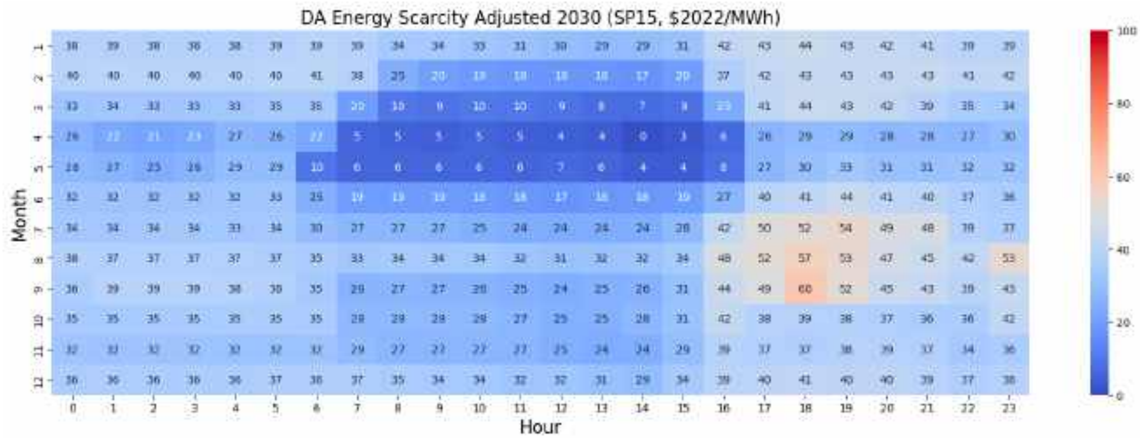
2022 ACC: 2024 SP-15 Day Ahead Market Prices



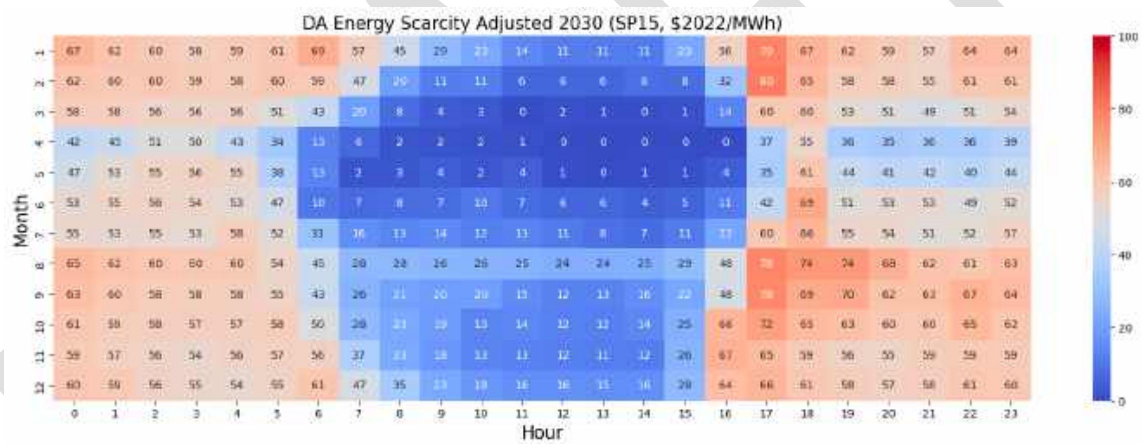
2024 ACC: 2024 SP-15 Day Ahead Market Prices



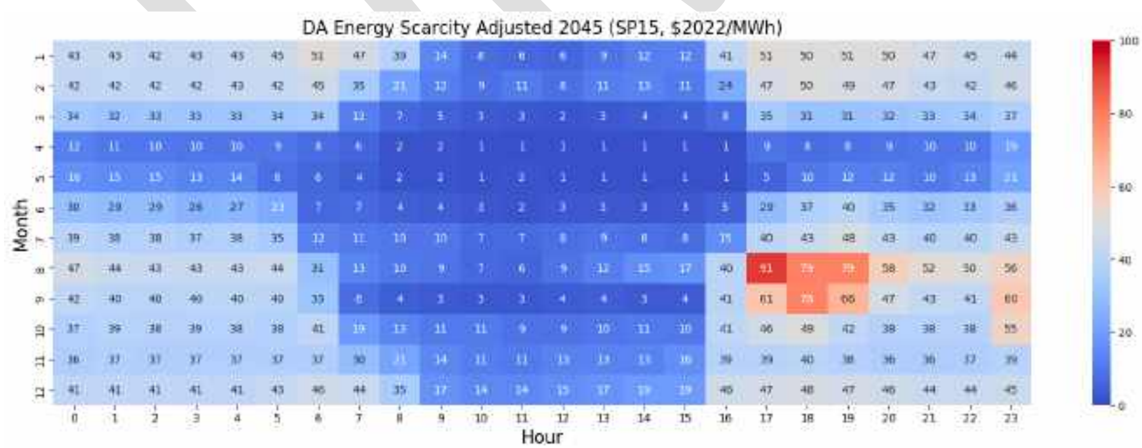
2022 ACC: 2030 SP-15 Day Ahead Market Prices



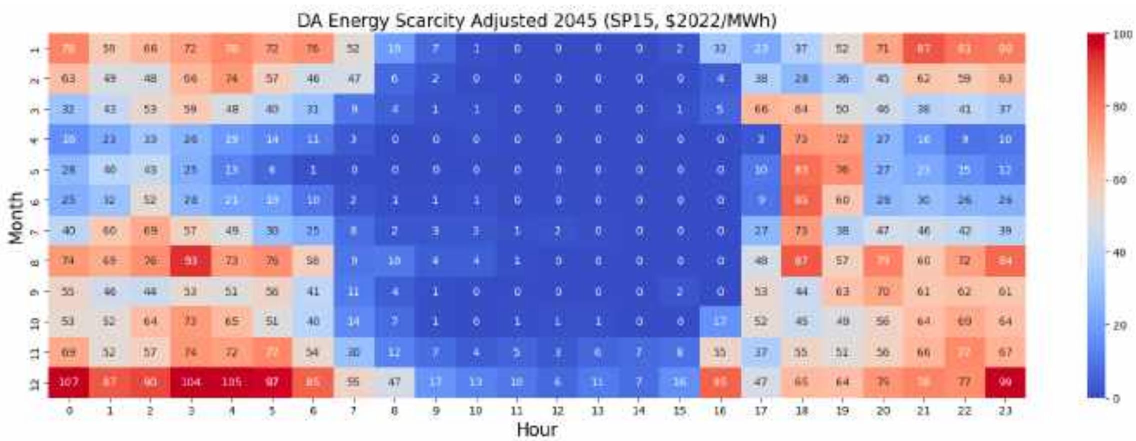
2024 ACC: 2030 SP-15 Day Ahead Market Prices



2022 ACC: 2045 SP-15 Day Ahead Market Prices



2024 ACC: 2045 SP-15 Day Ahead Market Prices



12.2 Example GHG Rebalancing Calculations

This section presents example calculations for the GHG emissions impact and associated avoided costs. Using the methods described above, the examples add load to the electric grid and calculate the resulting increase in GHG emissions costs. To illustrate the combination of hourly marginal emissions and portfolio rebalancing impacts, we consider two electrification measures: 1) a commercial heat pump that adds air conditioning load in the middle of the day and 2) unmanaged residential EV charging that adds load in the evening. Each measure adds 3,000 MWh of electric load, but at different times of the day.

Emissions Intensity: Starting with a simple example, we begin with a supply portfolio of three resources: 1) a Combined Cycle Gas Turbine (CCGT) with an emissions rate of 0.40 tons/MWh, 2) Stand-alone utility scale PV and 3) PV integrated with long-duration energy storage that can avoid curtailment and deliver carbon free electricity in the evening. The IRP targets procurement of 10,000 MWh with 4,000 MWh of CCGT, 3,000 MWh of PV and 3,000 MWh of PV integrated storage. The resulting energy sector emissions are 1,600 tons with an average grid intensity of 0.16 tons/MWh.

GHG Cost per Ton: The cap-and-trade value is $80/ton and the IRP GHG value is $110/ton, making the GHG Adder $30/ton ($110-$80). In the two examples presented below, 3,000 MWh of load are added. To meet an intensity target of 0.16 tons/MWh with an addition of 3,000 MWh, only 480 tons of GHG may be added.

Unmanaged EV Charging Example: In this first example, 3,000 MWh of unmanaged residential EV charging load is added in the evening. No PV generation is available, and the new demand is met with an increase of 3,000 MWh of CCGT generation. However, this results in an hourly marginal emissions increase of **1,200 tons** of GHG that increases the grid emissions intensity to 0.22 tons/MWh. The resource portfolio must be rebalanced to reduce emissions by 720 in order to limit additional GHG emissions to only **480 tons** and achieve the annual target of 0.16 tons/MWh.

In the first step, the 1,200 tons of additional marginal GHG emissions are valued at the cap-and-trade value of $80/ton and the GHG Adder cost of $30/ton for a total cost of $132,000. This reflects the economy wide cost placed on GHG emissions. In the second step, we reflect the cost savings of rebalancing the supply portfolio to allow 480 tons of emissions in order to meet the electric sector intensity target of 0.16 tons/MWh. The rebalanced portfolio allowed emission increase of 480 tons is valued at the GHG adder value of $30/ton for a total cost reduction of $14,400. In total, of the allowable GHG emissions in step 1 ($132,000) and the portfolio rebalancing in step 2 (-$14,400) nets to $117,600. This equates to a cost of $98/ton for the 1,200 Tons of added marginal emissions and $39/MWh for the added 3,000 MWh of load.

Table 12-1. GHG Cost: Unmanaged EV Charging Example

		A	B	C	
		GHG Cost ($/ton)	Emissions (tons CO2)	Cost ($) (A*B)	
1	Tons added		1,200		
2	Tons allowed by intensity target		480		*0.16t/MWH * L8*
	Marginal emissions impacts				
3	Cap and Trade	$80.00	1,200	$96,000	
4	GHG Adder	$30.00	1,200	$36,000	
5	Total marginal emission cost			$132,000	*L3 + L4*
	Rebalancing Impacts				
6	GHG Adder	$30.00	(480)	-$14,400	
7	**Net GHG cost**			**$117,600**	*L5 + L6*
8	Usage added (MWh)	3000			
9	Net GHG cost per MWh			$39.20	*L7/L8*
10	Net GHG Cost per ton of added marginal emissions			$98.00	*L7/L1*

Space Heating Electrification Example: For the second measure, 3,000 MWh of commercial space heating load is added during the day, using 2,500 MWh of carbon free PV and 500 MWh of CCGT generation. Only **200 tons** of hourly marginal GHG emissions are added, reducing the average grid intensity to 0.14 tons/MWh. This is below the annual target of 0.16 tons/MWh. To meet the 0.16 tons/MWh target emission intensity level, **480 tons** of increased emission would be allowed based on electrification load of 3000 MWh.

In step 1, the 200 tons of hourly marginal emissions are valued at the cap-and-trade price of $80/ton and the GHG Adder cost of $30/ton for a total cost of $22,000. In step 2, the portfolio is rebalanced to allow for an increase of 480 tons which are valued at the GHG Adder cost of $30/ton for a cost reduction of $14,400. In total the cooling load increases GHG costs by only $7,600. Dividing the $7,600 in GHG costs by the 200 tons of marginal GHG impacts results in a savings of $38/Ton. The reduced GHG costs divided by the 3,000 MWh of added load results in a GHG cost of $2.5/MWh.

Table 12-2. GHG Cost: Commercial Space Heating Electrification Example

		A	B	C	
		GHG Cost ($/ton)	Emissions (tons CO2)	Cost ($) (A*B)	
1	Tons added		200		
2	Tons allowed by intensity target		480		*0.16t/MWH * L8*
	Marginal emissions impacts				
3	Cap and Trade	$80.00	200	$16,000	
4	GHG Adder	$30.00	200	$6,000	
5	Total marginal emission cost			$22,000	*L3 + L4*
	Rebalancing Impacts				
6	GHG Adder	$30.00	(480)	-$14,400	
7	**Net GHG cost**			**$7,600**	*L5 + L6*
8	Usage added (MWh)	3000			
9	Net GHG cost per MWh			$2.53	*L7/L8*
10	Net GHG Cost per ton of added marginal emissions			$38.00	*L7/L1*

12.3 Utility-Specific Transmission Costs

12.3.1 PG&E

Transmission marginal capacity costs for PG&E typically come from PG&E's GRC proceedings. PG&E has estimated those values for ratemaking purposes using the Discounted Total Investment Method (DTIM). The DTIM calculates the unit cost of transmission capacity as the present value of peak demand driven transmission investments divided by the present value of the peak demand growth. This unit cost is then annualized using a Real Economic Carrying Charge (RECC) with adjustments for other ratepayer-borne costs, such as administrative and general costs (A&G) and operations and maintenance costs (O&M). This most recent calculation as performed by PG&E is provided in Table , with a derived marginal transmission capacity cost of $12.02/kW-yr (in 2021$).

However, in the CPUC Decision 21-11-016 published November 18, 2021, the Commission shifted to adopt the Solar Energy Industries Association's proposed marginal transmission capacity cost of $52.45 per kilowatt year (in 2021$). This value was used in the 2022 ACC update and is still in place (converted to $53.21 in 2023$) at the time of the 2024 ACC update.

Table 12-3. Derivation of PG&E Marginal Transmission Avoided Costs
(From PG&E 2020 GRC Ph II MTCC Model. Table Title retained from the PG&E model)

Table 3: Marginal Transmission Capacity Cost (2021 $) at 5-Year Time Horizon

[A]		[B]
PV of Investment ($)	[1]	$206,142,713
PV of Load Growth (MW)	[2]	1,793
PV of Load Growth (kW)	[3]	1,793,203
Marginal Investment ($/MW)	[4]	$114,958
Marginal Investment ($/kW)	[5]	$115
Annual MC Factor	[6]	10.46%
Marginal Transmission Capacity Cost ($/MW-Yr)	[7]	$12,022
Marginal Transmission Capacity Cost ($/kW-Yr)	[8]	$12.02

Notes:

[1] = The Cumulative Discounted Project Cost for the selected time horizon, multiplied by 10^6 from the CALC_DTIM PV Investments & Load tab.

[2] = The Cumulative Discounted Load Growth for the selected time horizon from the CALC_DTIM PV Investments & Load tab.

[3] = [2] x 1,000.
[4] = [1] / [2].
[5] = [1] / [3].
[6]: See CALC_Annual MC as % tab.
[7] = [4] x [6].
[8] = [5] x [6].

12.3.2 SCE

SCE does not include estimates of transmission capacity costs in its GRC proceedings. The consultant therefore calculates marginal transmission costs for SCE using information provided by SCE in response to Energy Division data requests. The utility is responsible for determining which projects to include under the systemwide transmission investments grouping vs. as individual large projects. For the 2024 ACC update, SCE has forecasted approximately $~~228M~~ 578M in transmission investments for capacity needs in the period from 2023-2027. Over the five years, ~~A~~ $95M in investment is tied to a single project that serves just under 5% of SCE's load and is associated with an average 15 MW per year of local load growth. Another $351M in investment is tied to a project which serves -2.5% of SCE's load and is associated with an average 2 MW per year of local load growth. The remaining $133M includes two additional projects driven by system wide load growth. Given the different drivers of the projects (system load versus local load), the DTIM is applied to the system-wide projects and the LNBA method to the separate $95M and $351M projects.

12.3.2.1 SCE DTIM Calculation for System Projects

The DTIM was applied in the 2022 ACC update to the SCE system-wide Pardee-Sylmar project and in the 2024 ACC update to both the Pardee-Sylmar project and the recently begun New Serrano project. Both projects are considered system-wide projects because SCE indicated that need is driven by SCE system peaks, rather than local peaks. The DTIM process applied to the SCE data is largely consistent with that from prior years. The primary modification from the 2022 ACC is to take median load growth over a longer forecast period to address the 'lumpiness' of transmission investment planning and better align the value of transmission investments with the system load growth over the lifetime of the investments.

The need for such a modification was noted in the 2022 ACC update, where declining peak loads in the near term would have resulted in calculating a negative transmission investment value, although the transmission investments were intended to address load growth into the future, rather than solely the near term. To address this issue, the 2022 ACC update used the median peak load growth for SCE over the period of 2021 through 2029, instead of only aligning investment in a given year with the change in load in that same year. In the 2024 ACC update, the median peak load growth is taken from the years 2023-2040 based on the forecast data available from IEPR and the longer expected useful life of systemwide transmission investments.

The two SCE system-wide projects have a cumulative discounted investment cost of $108M over the five-year horizon, and the median growth forecast (taken from 2023-2040 but only applied to five years) has a cumulative discounted growth of 677MW over the five-year analysis period. Combined with SCE's Annual MC factor, the resulting DTIM transmission marginal cost (without O&M) is $13.80 kW-yr for this systemwide projects.

Table 12-4. Derivation of SCE Marginal Transmission Avoided Costs for System Wide Projects (Without O&M)

PV of Investment ($M)	[1]	$107.77
PV of Load Growth (MW)	[2]	677
PV of Load Growth (kW)	[3]	676,884
Marginal Investment ($/MW)	[4]	$159,213
Marginal Investment ($/kW)	[5]	$159.21
Annual MC Factor	[6]	8.67%
O&M ($/kW-yr) (to be added later)	[7]	
Marginal Transmission Capacity Cost ($/kW-Yr)	[8]	$13.80

Notes:

[1] = The Discounted Project Cost of the Pardee Sylmar System-wide transmission project
[2] = The Cumulative Discounted Load Growth based on Median IEPR forecast without incremental DER
[3] = [2] x 1,000.
[4] = [1] * 10^6 / [2].
[5] = [1] * 10^6 / [3].
[6]: See Derivation of SCE Transmission Annual MC Factor
[7] = Value of $2.58 provided separately in response to data request on Marginal Transmission Cost factor. O&M is *Not* applied here for SCE and instead is added later, consistent with prior ACC cycles and to avoid double counting
[8] = [5] x [6]

Table 12-5. SCE Systemwide Transmission Project Costs and Load Forecasts

	Project Cost ($M) - Systemwide Projects			SCE Forecast from IEPR		
Year	Pardee Sylmar	New Serrano	Total	Forecast for SCE (MW)	Annual Peak Demand Growth (MW)	Median Growth (2023-2040)
				25175		
2023	3.817	0	3.817	25388	213	156
2024	1.09	1.92	3.01	25739	351	156
2025	2	12	14	25603	(136)	156
2026	5.956	24	29.956	25409	(194)	156
2027	0	82.08	82.08	25230	(179)	156
2028				25284	54	156
2029				25254	(30)	156
2030				25300	46	156
2031				25372	72	156
2032				25521	149	156
2033				25684	163	156
2034				25885	201	156
2035				26322	437	156
2036				26293	(29)	156
2037				26730	437	156
2038				26902	172	156
2039				27089	187	156
2040				27358	269	156
NPV (2023 - 2027)			$107.77			676.9

Notes:	SCE Data request response: ED-SCE-ACC Transmission-2024 - 2/23/2024
IEPR source for 2023-2040 data:	IEPR CEC Forecast 2023-2040 Baseline Forecast-Mid Demand Cast. Form 1.5 - SCE Planning Area: 1-in-10 Load Forecast. Historical and Extreme Temperature Non-Coincident Peak Demand (MW).
IEPR source for 2022 data:	IEPR CEC Forecast 2021-2035 Baseline Forecast-Mid Demand Cast. Form 1.5 Extreme Temperature Peak Demand (MW) 1-in-10. Located at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-
Real Discount Rate Used:	4.92%

Table 12-6. Derivation of SCE Transmission Annual MC Factor

Loaders & Financial Factors Inputs:			
Transmission Real Economic Carrying Charge (RECC)	[1]	6.97%	
Electric Transmission O&M ($/kW-yr)	[2]	$2.58	(To be added later)
A&G Payroll Loading Factor Transmission (Capital basis)	[3]	1.40%	
General Plant Loading Factor Transmission (Annual Capital basis)	[4]	2.07%	
Materials and Supplies Carrying Charge (Plant Based)	[5]		
Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized)	[6]		
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]	1.79%	
MARGINAL INVESTMENT			
Marginal Investment	[8]	$100.00	
Annualized Marginal Investment	[9]	$6.970	[9] = [8] x [1]
MARGINAL EXPENSES			
O&M Expense (to be added directly, rather than included as a factor)	[10]		
A&G Expense	[11]	$1.40	[11] = [8] x [3]
General Plant	[12]	$0.14	[12] = [9] x [4]
Sub-total Marginal Expenses	[13]	$1.544	[13] = [10] + [11] + [12]
WORKING CAPITAL ALLOWANCE			
Materials and Supplies On-hand	[14]		
Cash Working Capital	[15]		
Sub-total Carrying Costs	[16]		[16] = [14] + [15]
Franchise Fees and Uncollectibles	[17]	$0.15	[17] = ([9] + [13] + [16]) x [7]
Marginal Cost	[18]	$8.67	[18] = [9] + [13] + [16] + [17]
Annual Marginal Cost Factor	[19]	8.67%	[19] = [18] / [8]

12.3.2.2 SCE Large Project Transmission Marginal Cost

The LNBA method was specifically developed in the DRP to estimate avoided capacity costs for individual projects.[49] The LNBA method calculates the value of deferring the original project and divides that value by the peak net load reduction needed to obtain that deferral. This deferral value per kW is then annualized over the planning period and adjusted for the additional cost factors such as taxes (in the present value revenue requirement factor) and A&G. O&M is added to the marginal costs after the system wide and individual large project marginal costs are combined to avoid double counting.

For the 2021 and 2022 ACC updates, it was determined that SCE's Alberhill project was relevant to the transmission avoided capacity cost as a separate large project and should be included following the LNBA method. This project is again included for the 2024 ACC, with the same method applied. The deferral by one year of all investments in the multi-year capital plan results in a present value savings of $3.55M in direct costs, which translates to a value of $295 per kW of load growth addressed, or $59.57/kW-yr~~.~~

Since the transmission capacity cost will be applied to the entire SCE service territory, the next step is the calculate the equivalent avoided capacity cost for all of SCE. The paradigm assumed is that projects with this cost per kW of load growth would be required in the future in SCE's service territory. Since the location of project need is uncertain, the project value is converted into a uniform capacity value across the entire

[49] ~~Details on the LNBA method can be found here: https://drpwg.org/sample-page/drp/ under *Joint IOU Demo B LNBA Tool.*~~

service territory.~~-~~ In this case, the project area represents 4.4% of SCE's peak loading, so the equivalent avoided cost is $2.61/kW-yr (the ~~total~~ project marginal cost of $59.57/kW-yr multiplied by 4.4%).

For the 2024 ACC update, SCE also identified an additional project for inclusion as a separate large transmission ~~project~~ investment subject to the LNBA method. This project, related to the construction of a new Wildlife substation, resulted in a total project marginal cost of $~~224.24~~1,266.28/kW-yr. ~~and the~~The project area represents 2.4% of SCE's peak loading, ~~for~~ resulting in an equivalent systemwide average avoided cost of $~~5.48~~30.96/kW-yr.

Table 12-7. ~~SCE~~ Derivation of SCE Transmission Capacity Costs for Alberhill and Wildlife Projects using the LNBA Method (values in 2023$)

Alberhill Project Cost (LNBA Method for large projects)

1	Discount Rate	7.0085%	
2	Inflation Rate	1.99%	
3	Real Discount Rate	4.92%	(1+[1])/(1+[2]) - 1
4	Planning Horizon (yrs)	10	
5	RECC (For LNBA method)	12.30%	([1]-[2])/(1+[1])*((1+[1])^[4])/(((1+[1])^[4])-((1+[2])^[4]))

	Year	Project Cost ($M)	Peak Demand Growth (MW)	1 Yr Deferral Value ($M)	Deferral Value ($/KW)		
6	2023	1.101	12	0.05	4.30		
7	2024	1.572	11	0.07	6.70		
8	2025	1.048	23	0.05	2.14		
9	2026	17.117	19	0.80	42.25		
10	2027	73.95	11	3.47	315.28		
11	2028		9	0.00	0.00		
12	2029		13	0.00	0.00		
13	2030		11	0.00	0.00		
14	2031		16	0.00	0.00		
15	NPV using Real Discount Rate [NPV([3],[All Deferral Values above])]			3.55	**294.87**		
16	RECC (From Above) [5]					12.3%	
17	Present Value Revenue Requirement Factor					1.56	
18	LNBA Value ($/kW-yr) [15 (full deferral value)] * [16] * [17]						$56.56
19	A&G (1.40%) * [18]					1.40%	$0.79
20	General Plant (2.07%) * [18]					2.07%	$1.17
21	Franchise Fees (1.79%) * ([18] + [19] + [20])					1.79%	$1.05
22	Total Project Marginal Cost ($/kW-yr) [18] + [19] + [20] + [21]						$59.57
23	Percent of system load						4.375%
24	**Project Marginal Cost spread across the system [22] * [23]**						**$2.61**

Wildlife Project Cost (LNBA Method for large projects)

1	Discount Rate	7.0085%	
2	Inflation Rate	1.99%	
3	Real Discount Rate	4.92%	(1+[1])/(1+[2]) - 1
4	Planning Horizon (yrs)	10	
5	RECC (For LNBA method)	12.30%	([1]-[2])/(1+[1])*((1+[1])^[4])/(((1+[1])^[4])-((1+[2])^[4]))

#	Year	Project Cost ($M)	Peak Demand Growth (MW)	1 Yr Deferral Value ($M)	Deferral Value ($/kW)		
6	2023	0.9	1	0.04	42.21		
7	2024	0.9	2	0.04	21.10		
8	2025	75.198	2	3.53	1763.32		
9	2026	212.832	2	9.98	4990.71		
10	2027	61.133	4	2.87	716.76		
11	2028		0	0.00	0.00		
12	2029		0	0.00	0.00		
13	2030		0	0.00	0.00		
14	2031		0	0.00	0.00		
15	NPV using Real Discount Rate [NPV([3],[All Deferral Values above])]			13.62	8268.13		
16	RECC (From Above) [5]					12.3%	
17	Present Value Revenue Requirement Factor					1.56	
18	LNBA Value ($/kW-yr) [15 (full deferral value)] * [16] * [17]						$1,202.29
19	A&G (1.40%) * [18]					1.40%	$16.83
20	General Plant (2.07%) * [18]					2.07%	$24.89
21	Franchise Fees (1.79%) * ([18] + [19] + [20])					1.79%	$22.27
22	Total Project Marginal Cost ($/kW-yr) [18] + [19] + [20] + [21]						$1,266.28
23	Percent of system load						2.445%
24	**Project Marginal Cost spread across the system [22] * [23]**						**$30.96**

Note that the RECC factor used in the LNBA method is different from the RECC factor used in the DTIM method above. The DTIM RECC annualizes the full unit cost of the projects over the life of the project (50-60 years) and reflects revenue requirement components (e.g., taxes) that increase the cost of the project to ratepayers. This is equivalent to value of deferring the revenue requirement cost of the project and all of the project's future replacements by one year. This paradigm of the one-year replacement value is how the RECC was originally developed in the Electric Utility Rate Design Study Task Force 4 by NERA for EPRI (NP-22555). The LNBA method follows this same deferral concept, but directly calculates the value of deferring projects over each year over the planning horizon. Because the LNBA method sums the deferral value of projects over multiple years, a RECC is used to convert that multi-year value back to a $/kW-yr value needed for marginal costing. The RECC used for the LNBA method annualizes the total deferral value over the planning horizon (10 years) and does not include the Present Value Revenue Requirement Factor effects. For the LNBA, the RECC is utilized as a capital recovery factor that is constant in real dollars. A typo in the RECC equation ~~noted~~ listed in the 2021 and 2022 ACC external documentation is corrected here. This typo did not affect the RECC calculation itself for prior cycles, only ~~the~~ what was described in the documentation ~~description~~.

Table 12-8. Total SCE Transmission Marginal Cost ($/kW-yr 2023$)

	Marginal Cost ($/kW-yr)
System-wide projects	$13.80 / kW-yr
Alberhill project averaged over SCE system	$2.61 / kW-yr
Wildlife project averaged over SCE system	$~~5~~30.96~~48~~ / kW-yr
Transmission O&M	$ 2.58 / kW-yr
Total	**$~~24~~49.49~~57~~ / kW-yr**

Transmission O&M is from SCE's 2024 Data Request Response

12.3.3 SDG&E

Similar to SCE, SDG&E does not provide estimates of transmission capacity costs in its GRC proceedings. Therefore, the DTIM method is applied to transmission projects determined by SDG&E to be systemwide and potentially deferrable by DER. The derivation method for the Marginal Transmission Capacity Cost as displayed in Table is the same as that applied for SCE, including the same modification to take the median load growth over an extended forecast period. The primary difference in data between the two utilities is that SDG&E includes 6 years in its planning horizon rather than the 5 of SCE, so all 6 years are included. This is consistent with the prior ACCs. The calculation of the SDG&E Transmission Annual MC Factor for the 2024 ACC cycle includes updated inputs provided by SDG&E in response to Energy Division data requests.

Table 12-9. Derivation of SDG&E Marginal Transmission Avoided Costs

PV of Investment ($M)	[1]	$143.15
PV of Load Growth (MW)	[2]	512.04
PV of Load Growth (kW)	[3]	512,045
Marginal Investment ($/MW)	[4]	$279,570
Marginal Investment ($/kW)	[5]	$279.57
Annual MC Factor	[6]	13.64%
	[7]	
Marginal Transmission Capacity Cost ($/kW-Yr)	[8]	$38.13

Notes:
[1] = The Cumulative Discounted Project Cost of SDG&E Transmission Projects
[2] = The Cumulative Discounted Load Growth based on Mid-Low IEPR
[3] = [2] x 1,000.
[4] = [1] * 10^6 / [2].
[5] = [1] * 10^6 / [3].
[6]: See Derivation of SDG&E Transmission Annual MC Factor
[7]: Consistent with the prior ACC, O&M was not input in the DTIM calculation for SDG&E, though the value is included indirectly via the MC Factor
[8] = [5] x [6]

Table 12-10. Derivation of SDG&E Systemwide Transmission Project Costs and Load Forecasts

Year	SDG&E XMSN Capital Expenditures ($M)	SDG&E Forecast from IEPR: SDG&E Forecast (MW)	SDG&E Forecast from IEPR: Annual Peak Demand Growth (MW)	SDG&E Forecast from IEPR: Median Growth (2023-2040)
		4,583		
2023	25.8	4,739	156	102
2024	53.0	4,755	16	102
2025	28.1	4,775	20	102
2026	28.2	4,811	36	102
2027	19.9	4,855	44	102
2028	11.6	4,935	80	102
2029		5,006	71	102
2030		5,113	107	102
2031		5,188	75	102
2032		5,299	111	102
2033		5,415	116	102
2034		5,549	134	102
2035		5,654	105	102
2036		5,775	121	102
2037		5,881	106	102
2038		6,006	125	102
2039		6,105	99	102
2040		6,194	89	102
NPV(2023-2028)	$143.15			$12.04

Annual Transmission Escalation Factors from SCE planning

Year	%
2023	10.20%
2024	3.10%
2025	0.10%
2026	-0.60%
2027	-0.90%
2028	-0.20%
Average (2023-2028)	1.95%

Notes:	SDG&E Response to 1.31.2024 Transmission Data Request
IEPR source for 2023-2040 data:	CED 2023-2040 Forecast - Local Reliability Scenario - LSE and BAA Tables. Form 1.5d (1-in-10): SDG&E TAC Area
IEPR source for 2022 data:	Value for 2022 comes from the SDG&E forecast used in the 2022 ACC Update cycle (CEU 2020 Managed Forecast -LSE and BA Mid Demand - Low AAEE Case. Form 1.5d (1-in-10): SDG&E TAC Area)
Real Discount Rate Used:	5.35%

Table 12-11. Derivation of SDG&E Transmission Annual MC Factor

Item	Ref.	Value	Formula
Loaders & Financial Factors Inputs:			
Real Economic Carrying Charge (RECC)	[1]	7.16%	
Electric Transmission O&M Factor (%) (Capital Basis)	[2]	1.40%	
A&G Payroll Loading Factor Transmission (Capital basis)	[3]	0.81%	
General Plant Loading Factor Transmission (Capital basis)	[4]	2.77%	
Materials and Supplies Carrying Charge (Plant Based)	[5]		
Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized)	[6]	1.50%	
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]		
MARGINAL INVESTMENT			
Marginal Investment	[8]	$100.00	
Annualized Marginal Investment	[9]	$7.160	[9] = [8] x [1]
MARGINAL EXPENSES			
O&M Expense	[10]	$1.40	[10] = [8] x [2]
A&G Expense	[11]	$0.81	[11] = [8] x [3]
General Plant	[12]	$2.77	[12] = [8] x [4]
Sub-total Marginal Expenses	[13]	$4.980	[13] = [10] + [11] + [12]
WORKING CAPITAL ALLOWANCE			
Materials and Supplies On-hand	[14]		
Cash Working Capital	[15]	$1.50	[15] = [8] x [6]
Sub-total Carrying Costs	[16]	$1.50	[16] = [14] + [15]
Franchise Fees and Uncollectibles	[17]		
Marginal Cost	[18]	$13.64	[18] = [9] + [13] + [16] + [17]
Annual Marginal Cost Factor	[19]	13.64%	[19] = [18] / [8]

12.4 Derivation of Near-Term Distribution Marginal Capacity Costs

12.4.1 Unspecified Distribution Marginal Costs

Table shows the calculation of the unspecified distribution marginal cost that is used for the near-term distribution marginal capacity costs. Columns showing calculations for each load increasing and load decreasing DERs are provided for each utility, aligning with the modification noted in section 7.2. SCE's costs are further divided, as costs are provided separately for each facility type. The final SCE Total Distribution Capacity value is achieved by summing the circuit and B-Bank substation values with distribution deferral values for the A-Bank and subtransmission facilities.

Table 12-12. Unspecified Distribution Deferral Costs by IOU

Line		PG&E		SCE-Substations (B-Bank)		SCE-Circuits		SDG&E		Notes:
	Number of Overloads	Load Decreasing DERs	Load Increasing DERs	Load Decreasing DERs	Load Increasing DERs	Load Decreasing DERs	Load Increasing DERs	Load Decreasing DERs	Load Increasing DERs	
1	Actual Overloads	567	567	38	38	215	215	21	21	[1]
2	Counterfactual Overloads	809	435	65	37	300	0	24	19	[2]
3	Percentage of Overloads that can be Deferred by Load Transfers	20%	20%	20%	20%	20%	20%	9%	9%	From 2021 ACC
	Overload Capacity									
4	Actual Overloads (kW)	1,992,740	1,992,740	366,357	366,357	258,284	258,284	34,578	34,578	[4]
5	Counterfactual Overloads (kW)	2,281,663	1,393,994	443,727	339,408	294,280	245,743	48,040	27,193	[5]
5b	Estimated Overload Capacity Deferred by DERs (Includes Load Transfers) (kW)	288,923	-598,746	77,370	-26,949	35,996	-12,541	13,463	-7,385	[5] - [4]
6	Estimated Overload Capacity Deferred by DER - Excluding Load Transfers (kW)	231,138	-478,997	61,896	-21,559	26,797	-10,033	12,251	-6,720	[6] = [5b] x (100% - [3])
	Project & Planned Investment Costs									
7	Total Cost of Planned Investments in DDOR Filing ($)	$742,147,811	$742,147,811	$1,679,954,046	$1,679,954,046	$1,679,954,046	$1,679,954,046	$52,779,000	$52,779,000	[7]
8	Capacity Deficiency that Planned Investments Mitigate (kW)	$2,097,225	$2,097,225	$1,102,010	$1,102,010	$1,102,010	$1,102,010	$19,003	$19,003	[8]
9	Unit Cost of Deferred Distribution Upgrades ($/kW)	$353.87	$353.87	$1,524.45	$1,524.45	$1,524.45	$1,524.45	$2,777.47	$2,777.47	[9]* = [7] / [8]
	System Level Avoided Distribution Costs									
10	DER-Deferrable Capital Investment ($)	$81,793,266	-$169,503,262	$94,356,827	-$32,866,189	$43,899,149	-$15,294,212	$34,026,881	-$18,665,085	[10] = [9] x [6]
11	Total Load Reduction from DER forecasted across all facilities, 2023-2027 (kW)	4,612,280	-8,738,321	4,217,474	-3,293,416	4,217,474	-3,293,416	841,324	-1,154,662	[11]
12	Unspecified Distribution Deferral Value ($/kW of DER installed)	$17.73	$19.40	$22.37	$9.98	$10.41	$4.64	$40.44	$16.16	[12] = [10] / [11]
13	Marginal Distribution Cost Factor ('IOU Specific RECC') (%)	8.32%	8.32%	11.48%	11.48%	11.48%	11.48%	7.66%	7.66%	[13]
14	Capacity Deferral Value ($/kW of DER installed-yr)	$1.48	$1.61	$2.57	$1.15	$1.20	$0.53	$3.10	$1.24	[14] = [12] * [13]
	O&M Distribution Costs									
15	O&M Deferral Value ($/kW-yr)			$6.74	$6.74	$21.98	$21.98	$20.54	$20.54	[15]
16	O&M Deferral Value ($/kW of DER installed -yr)			$0.10	$0.04	$0.15	$0.07	$0.30	$0.12	[16] = [15] * [6] / [11]
17	Unspecified Marginal Cost ($/kW of DER installed-yr)	$1.48	$1.61	$2.57	$1.19	$1.35	$0.60	$3.40	$1.36	[17] = [14] + [16]

Line		SCE Substations (A-Bank)		SCE Subtransmission		Notes
		Load Decreasing DERs	Load Increasing DERs	Load Decreasing DERs	Load Increasing DERs	
18	Distribution Deferral Value ($/kW-yr)	$ 24.60	$ 24.60	$ 16.40	$ 16.40	*From SCE 2021 GRC Phase II Table I-11
19	Estimated Overload Capacity Deferred by DER - Excluding Load Transfers (kW)	61,896	-21,559	61,896	-21,559	* Using SCE Substation B-Bank Values [6]
20	Total Load Reduction from DER Forecasted Across Distribution System, 2023-2027 (kW)	4,217,474	-3,293,416	4,217,474	-3,293,416	* Using SCE Substation B-Bank Values [11]
21	Unspecified Marginal Cost ($/kW of DER installed-yr)	$0.36	$0.16	$0.24	$0.11	[21] = [18] * [19] / [20]

	SCE Total Distribution System		Notes
	Load Decreasing DERs	Load Increasing DERs	
Unspecified Marginal Cost ($/kW of DER installed-yr)	$4.61	$2.06	Sum of all SCE unspecified marginal costs [17] + [21] for each category

Line		PG&E	SCE	SDG&E	Notes
22	**Average Unspecified Marginal Cost ($/kW of DER installed-yr)**	$1.54	$3.34	$2.38	Average of values for load decreasing and load increasing DERs for each utility

Notes:

[1] Number of circuits or areas in the utility Grid Needs Assessment (GNA) that have a deficiency or overload over the planning horizon (2023-2027) based on the utility planning forecast that includes peak load reductions due to DER.

[2] Number of overloads expected to occur in a counterfactual scenario. As a part of the Grid Needs Assessment (GNA) each utility submitted a list of distribution areas with three key elements: a) Projected Load Forecasts (2023-2027) b) Projected DER adoption (2023-2027) and c) Facility Loading Limits.
The counterfactual forecast takes the planning forecast and adds back, or removes, the load reduction or load increase on each circuit that results from the projected DER reduction. A circuit or area is considered overloaded if the projected load forecast in any year (2023-2027) exceeds the facility loading limit.

[3] Share of proposed projects that could be deferred by load transfers or similar low-cost or no-cost solutions, labeled collectively as the load transfer ratio. This was only able to be calculated or estimated using earlier GNA + DDOR methodology for PG&E and SDG&E. The PG&E value had also been determined as a reasonable approximation for SCE. These values are preserved from the 2020 and 2021 ACC updates. In response to a data request from the Energy Division, the utilities each indicated that they do not currently have any recommendations for a better approach to estimate this input.

[4], [5] Sum of the maximum deficiency (kW) from 2023-2027 for each of the overloads identified in [1] and [2]

[5b] Overload capacity estimated to be deferred by DERs in the planning forecast (Counterfactual overloads minus actual overloads)

[6] Overload capacity estimated to be deferred by DERs in the planning forecast, multiplied by one minus the load transfer ratio in order to exclude overloads that would otherwise be expected to be avoided by load transfers or other low-cost or no-cost solutions.

[7-9] The average project cost per kW of deficiency in the planning case is used to estimate the cost of project upgrades under the counterfactual case. Project costs were only included if the project was proposed specifically to address a capacity overload. The project costs and associated grid needs are collected from the August 2023 Grid Needs Assessment and DDOR reports provided by the utilities, with further detail on projects noted provided in responses to Data Requests from the Energy Division and its consultant.

[11] Total forecasted DER was calculated by using the GNA and summing all DER adoption from 2023-2027 across all areas, including areas that were not overloaded.

[13] See following section: Derivation of Distribution Annual MC Factors~~Derivation of Distribution Annual MC Factors~~.

[15-16] O&M information is from data requests to the IOUs

12.4.2 Derivation of Distribution Annual MC Factors

As with Transmission, Annual MC Factors annualize the unit cost of capital investment using a RECC and adds adjustments for A&G, General Plant, Working Capital, and Franchise Fees and Uncollectables. PG&E also includes the cost of O&M in its RECC, whereas SCE and SDG&E provide O&M costs as a $/kW-yr cost separate from the RECC. The detailed derivations of the Annual MC Factors are shown in the following tables. Because none of the utilities have new approved GRC Phase II filings since the 2022 ACC, only certain individual inputs of these factors have been updated for the 2024 ACC, according to input from the utilities in data request responses.

Table 12-13. PG&E Distribution Annual MC Factor

Loaders & Financial Factors Inputs:			
	2024 ACC Values		
Real Economic Carrying Charge (RECC)	[1]	4.67%	
Electric Distribution O&M Loading Factor (Capital Basis)	[2]	2.46%	
A&G Payroll Loading Factor Distribution (Distribution O&M + A&G Basis)	[3]	31.63%	
General Plant Loading Factor Transmission (Transmission O&M + A&G Basis)	[4]	6.03%	
Materials and Supplies Carrying Charge (Plant Based)	[5]	0.88%	
Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized)	[6]	3.11%	
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]	1.0111	
MARGINAL INVESTMENT			
Marginal Investment	[8]	$100.00	
Annualized Marginal Investment	[9]	$4.67	[9] = [8] x [1]
MARGINAL EXPENSES			
O&M Expense	[10]	$2.46	[10] = [8] x [2]
A&G Expense	[11]	$0.78	[11] = [10] x [3]
General Plant	[12]	$0.20	[12] = ([10] + [11]) x [4]
Sub-total Marginal Expenses	[13]	$3.43	[13] = [10] + [11] + [12]
WORKING CAPITAL ALLOWANCE			
Materials and Supplies On-hand	[14]	$0.03	[14] = ([10] + [11]) x [5]
Cash Working Capital	[15]	$0.10	[15] = ([10] + [11]) x [6]
Sub-total Carrying Costs	[16]	$0.13	[16] = [14] + [15]
Franchise Fees and Uncollectibles	[17]	$0.09	[17] = ([9] + [13] + [16]) x ([7] - 1)
Marginal Cost	[18]	$8.32	[18] = [9] + [13] + [16] + [17]
Annual Marginal Cost Factor	[19]	8.32%	[19] = [18] / [8]

Notes:
[1] General RECC from 2023 PG&E DDOR Appendix E: LNBA Planned Investments - General Inputs
[2] E-Dist Primary Composite same as 2022 and 2021 ACC updates. From Table 1: Financial Factors provided in PG&E Response to OIR
[3] Distribution A&G from 2020 GRC Phase II Table 10-2 (Line 16)
[4] Distribution GPLF from 2020 GRC Phase II Table 10-2 (Line 17)
[5] M&S from 2020 GRC Phase II Table 10-2 (Line 18)
[6] CWC from 2020 GRC Phase II Table 10-2 (Line 19)
[7] FF&U from 2020 GRC Phase II Table 10-2 (Line 20)
PG&E confirmed that values 2-7 have not changed since the 2022 ACC Update - PG&E's next GRC Phase II filing will take place in late 2024

Table 12-14. SCE Distribution Annual MC Factor

Loaders & Financial Factors Inputs:			
Real Economic Carrying Charge (RECC)	[1]	9.24%	
Electric Distribution O&M ($/kW-yr)	[2]	$21.98	
A&G Payroll Loading Factor (Capital basis)	[3]	1.44%	
General Plant Loading Factor (Annual Capital basis)	[4]	7.30%	
Materials and Supplies Carrying Charge (Plant Based)	[5]		
Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized)	[6]		
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]	1.12%	
MARGINAL INVESTMENT			
Marginal Investment	[8]	$100.00	
Annualized Marginal Investment	[9]	$9.24	[9] = [8] x [1]
MARGINAL EXPENSES			
O&M Expense (to be added directly, rather than included as a factor)	[10]		[10] = included separately, not included in factors for SCE
A&G Expense	[11]	$1.44	[11] = [8] x [3]
General Plant	[12]	$0.67	[12] = [9] x [4]
Sub-total Marginal Expenses	[13]	$2.115	[13] = [10] + [11] + [12]
WORKING CAPITAL ALLOWANCE			
Materials and Supplies On-hand (currently not used)	[14]		
Cash Working Capital (currently not used)	[15]		
Sub-total Carrying Costs	[16]		
Franchise Fees and Uncollectibles	[17]	$0.13	[17] = ([9] + [13] + [16]) x [7]
Marginal Cost	[18]	$11.48	[18] = [9] + [13] + [16] + [17]
Annual Marginal Cost Factor	[19]	11.48%	[19] = [18] / [8]

Table 12-15. SDG&E Distribution Annual MC Factor

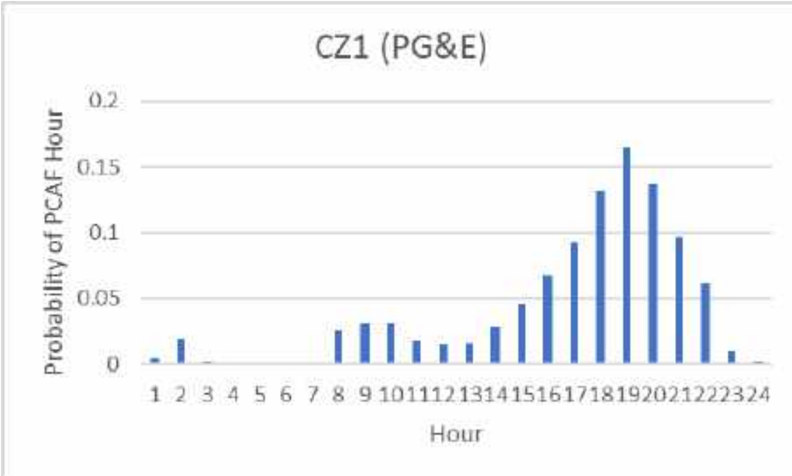
Loaders & Financial Factors Inputs:			
Real Economic Carrying Charge (RECC)	[1]	7.18%	
Electric Distribution O&M ($/kW-yr added later)	[2]	$20.54	
A&G Payroll Loading Factor Distribution (Annual Capital basis GPL)	[3]	1.72%	
General Plant Loading Factor Distribution (Annual Capital basis)	[4]	2.91%	
Materials and Supplies Carrying Charge (Plant Based)	[5]		
Cash Working Capital Carrying Charge (Capital Based)	[6]	1.99%	
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]		
MARGINAL INVESTMENT			
Marginal Investment	[8]	$100.00	
Annualized Marginal Investment	[9]	$7.18	[9] = [8] x [1]
MARGINAL EXPENSES			
O&M Expense (to be added directly, rather than included as a factor)	[10]		[10] = not included in factors (added separately)
A&G Expense	[11]	$0.13	[11] = [3] x ([9] + [12] + [15])
General Plant	[12]	$0.21	[12] = [4] x [9]
Sub-total Marginal Expenses	[13]	$0.34	[13] = [10] + [11] + [12]
WORKING CAPITAL ALLOWANCE			
Materials and Supplies On-hand	[14]		
Cash Working Capital	[15]	$0.14	[15] = [9] x [6]
Sub-total Carrying Costs	[16]	$0.14	[16] = [14] + [15]
Franchise Fees and Uncollectibles	[17]		
Marginal Cost	[18]	$7.66	[18] = [9] + [13] + [16] + [17]
Annual Marginal Cost Factor	[19]	7.66%	[19] = [18] / [8]

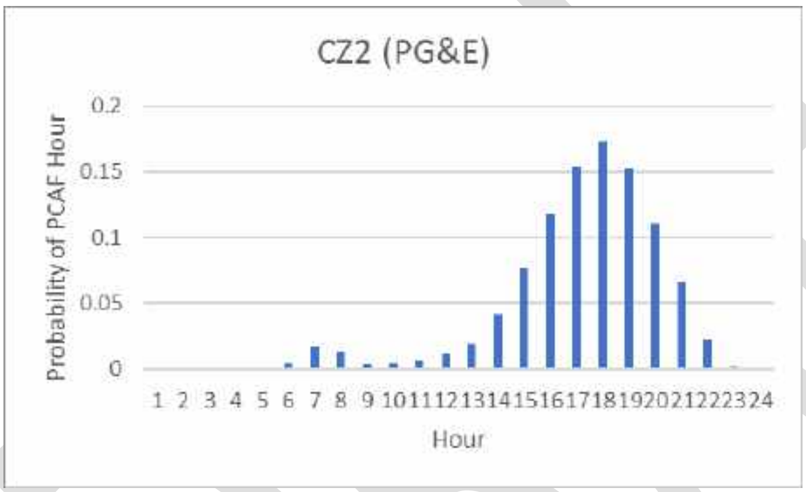
12.5 Utility Hourly PCAF Allocation by Climate Zone

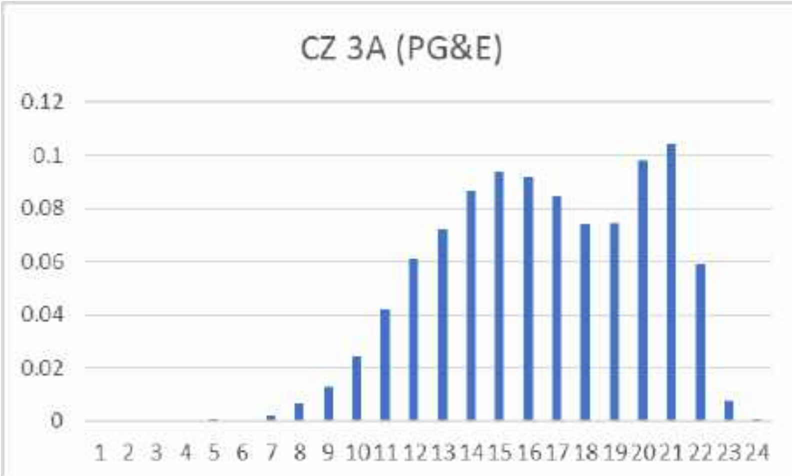
12.5.1 PG&E PCAFs

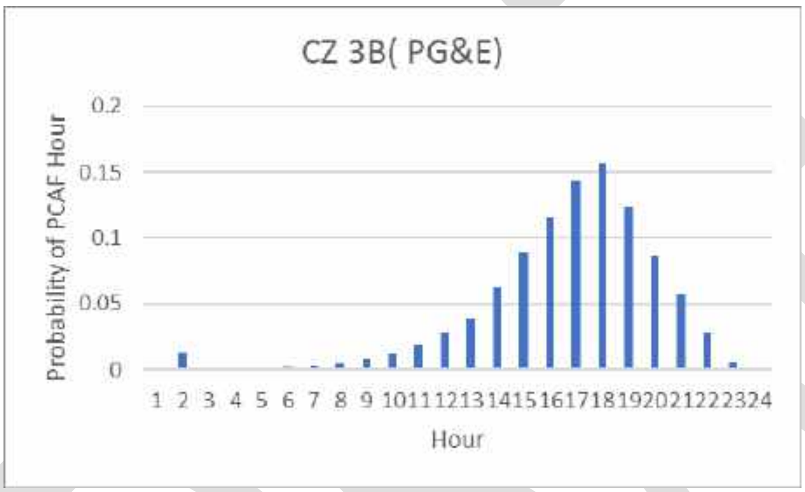
PG&E produces hourly peak capacity allocation factors by distribution area for their GRC filing. The PCAFs used in the 2024 ACC were provided by PG&E division and were the same data provided for the previous ACC, as this portion of the GRC Phase II proceeding has not been updated since the previous model. PG&E divisions were mapped to climate zones using the same methodology outlined in Table . If there was more than one division per climate zone, a weighted average of the PCAFs was taken.

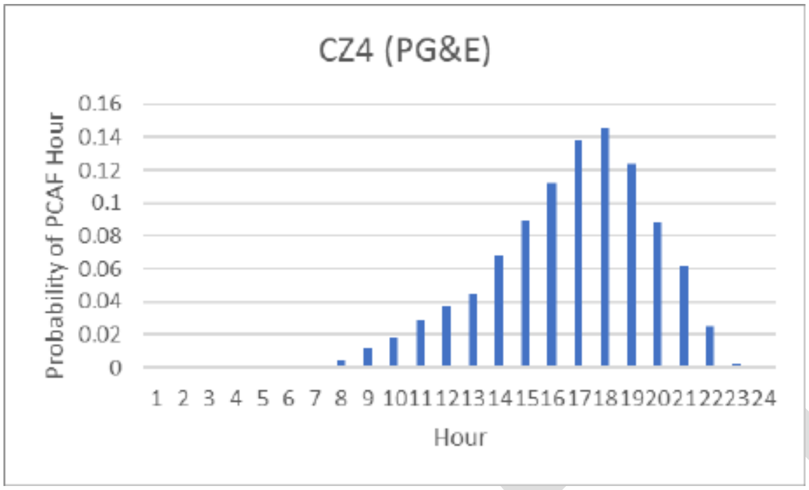
PG&E PCAFs by climate zone are shown below:

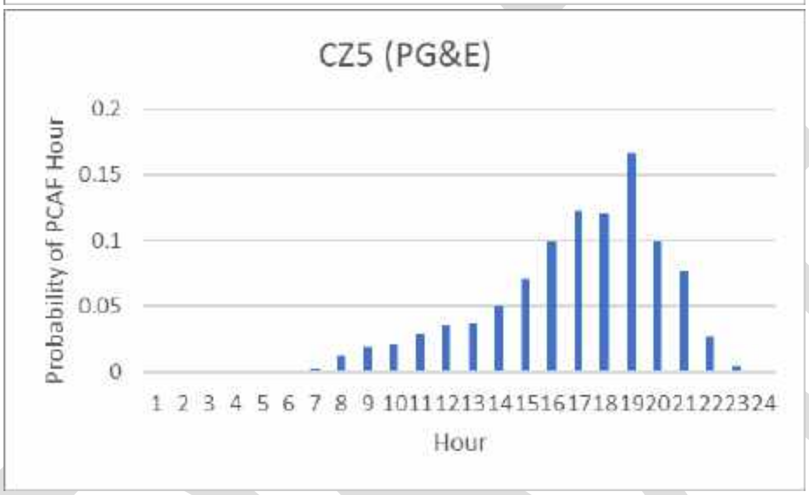

CZ1 (PG&E)
Probability of PCAF Hour
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

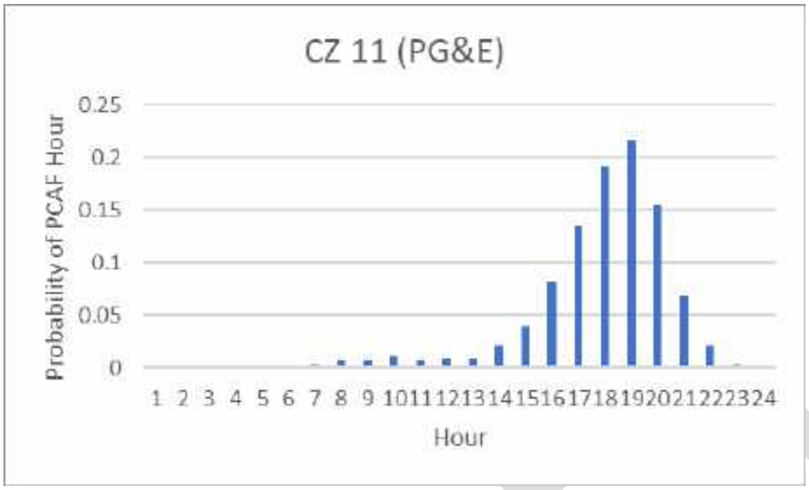

CZ2 (PG&E)
Probability of PCAF Hour
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

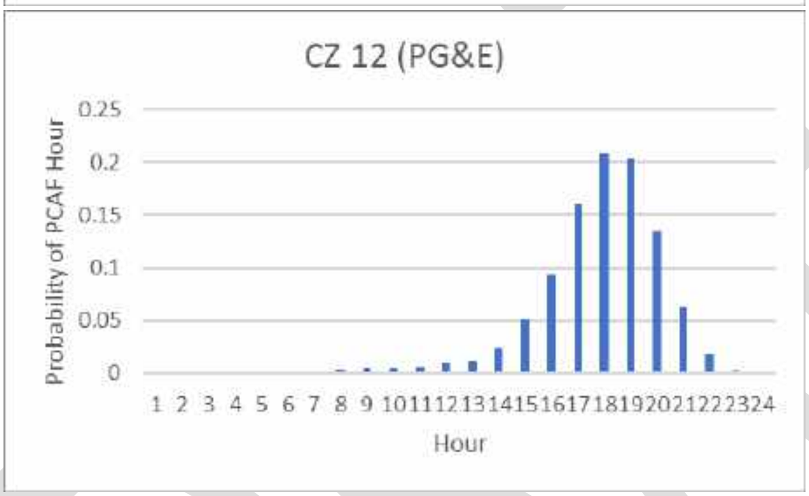

CZ 3A (PG&E)
0.12
0.1
0.08
0.06
0.04
0.02
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

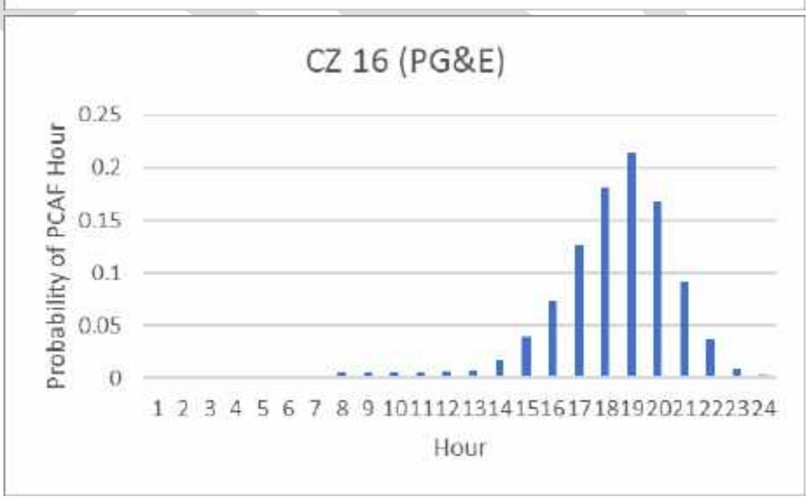

CZ 3B(PG&E)
Probability of PCAF Hour
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


CZ4 (PG&E)
Probability of PCAF Hour
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


CZ5 (PG&E)
Probability of PCAF Hour
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


CZ 11 (PG&E)
Probability of PCAF Hour
0.25
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


CZ 12 (PG&E)
Probability of PCAF Hour
0.25
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


CZ 16 (PG&E)
Probability of PCAF Hour
0.25
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

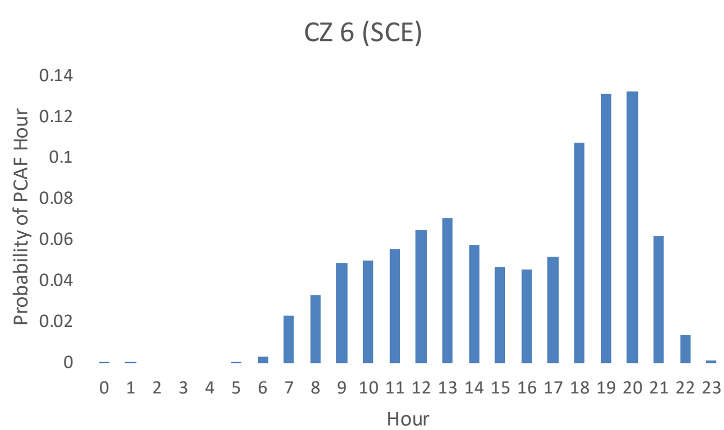
12.5.2 SCE Peak Load Risk Factors (PLRF)

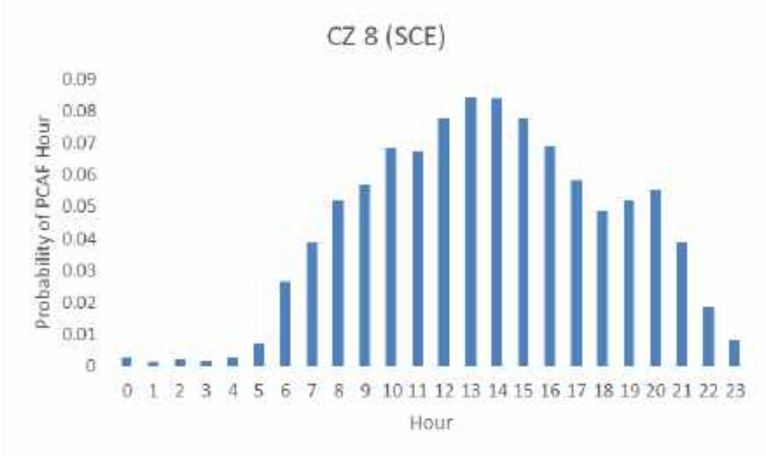
For SCE, the ACC utilizes the PLRF analysis completed by SCE in its 2021 GRC Phase II proceeding. As there has been no approved update to SCE's GRC Phase II proceeding since the 2022 ACC update, SCE's distribution PLRFs remain unchanged.

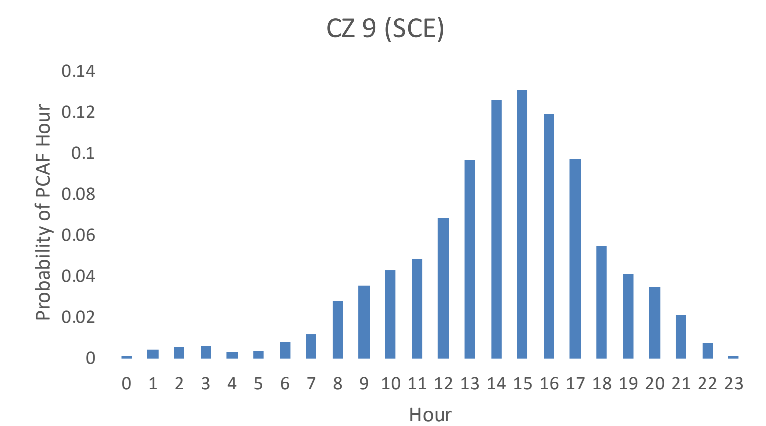
Regarding the use of the PLRF analysis in contrast to a PCAF methodology, SCE has noted that: "The PLRF methodology is a deterministic variant of the LOLE methodology used for generation capacity and uses the same conceptual framework of identifying hours of the year when expected load may result in an expected capacity constraint on the system. Since the distribution system is geographically disparate, the PLRF methodology is applied to each individual substation and circuit to take into account load diversity on the system."

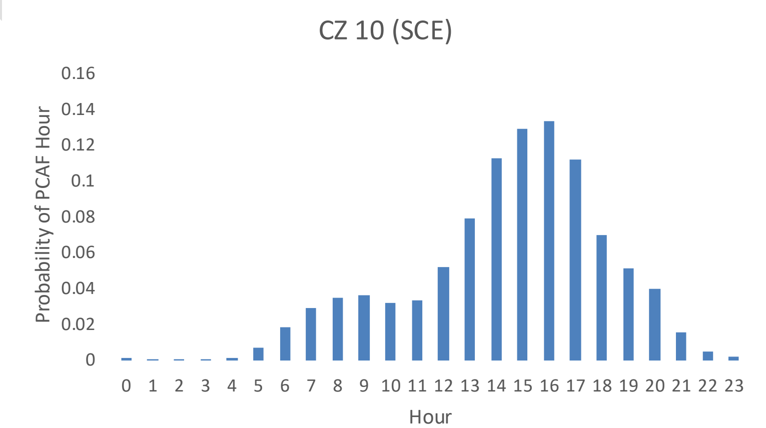
For its 2021 GRC, SCE provided an analysis forecasting future PLRFs for the 2024 calendar year. However, the consultant requires historical temperature data matching the PLRF year in order to align the PLRFs to a typical meteorological year. Per SCE's GRC filing and later confirmation via Energy Division data request, 2018 load data was referenced in creating the 2024 forecast and as such is considered to be the most appropriate reference year for aligning temperature data. The consultant has therefore aligned the PLRF and PCAF values as if the load and related temperature data were directly from the 2018 historical year.

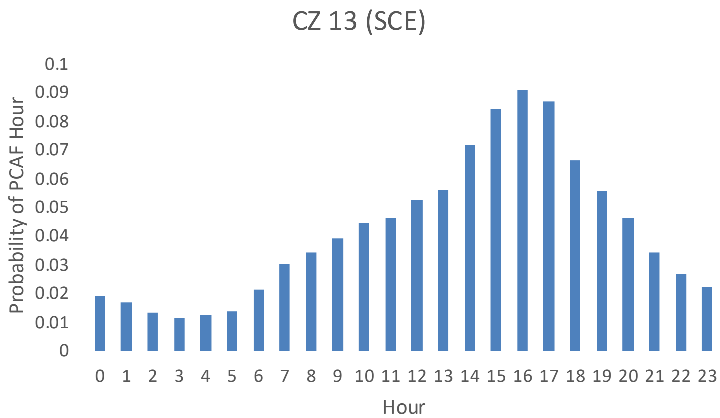
SCE PCAFs by climate zone are shown below.

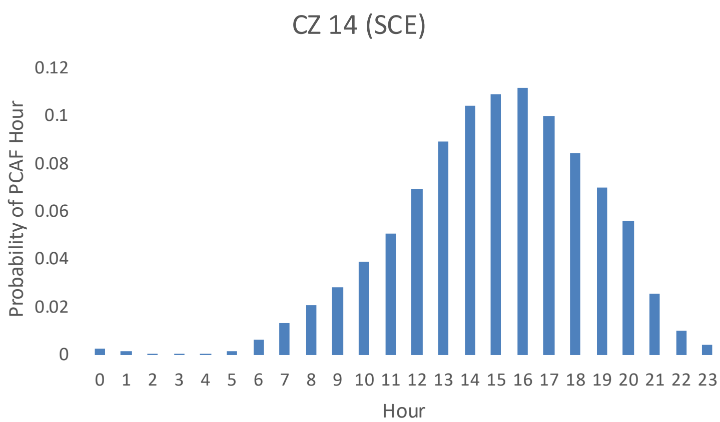


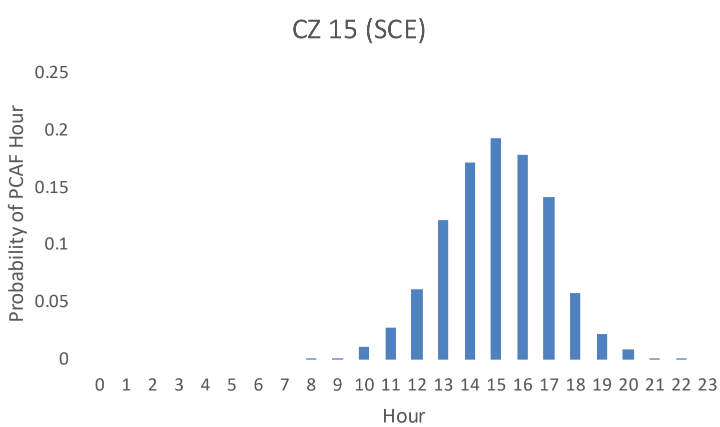

CZ 8 (SCE)
Probability of PCAF Hour
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour

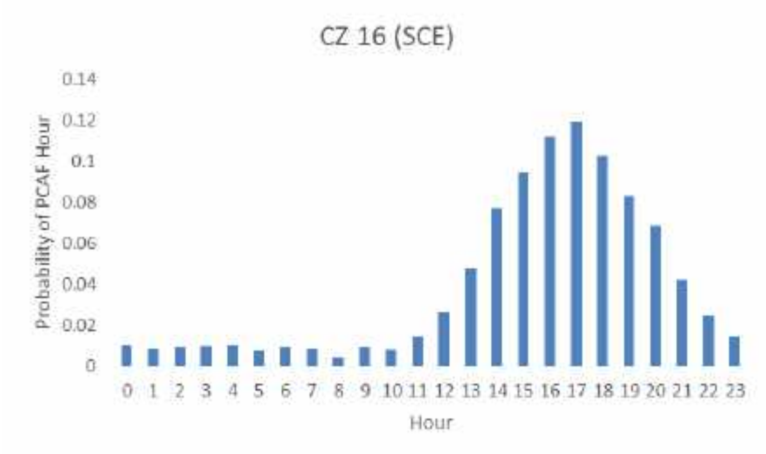

CZ 9 (SCE)
Probability of PCAF Hour
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


CZ 10 (SCE)
Probability of PCAF Hour
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


CZ 13 (SCE)
Probability of PCAF Hour
0.1
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


CZ 14 (SCE)
Probability of PCAF Hour
0.12
0.1
0.08
0.06
0.04
0.02
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


CZ 15 (SCE)
Probability of PCAF Hour
0.25
0.2
0.15
0.1
0.05
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour

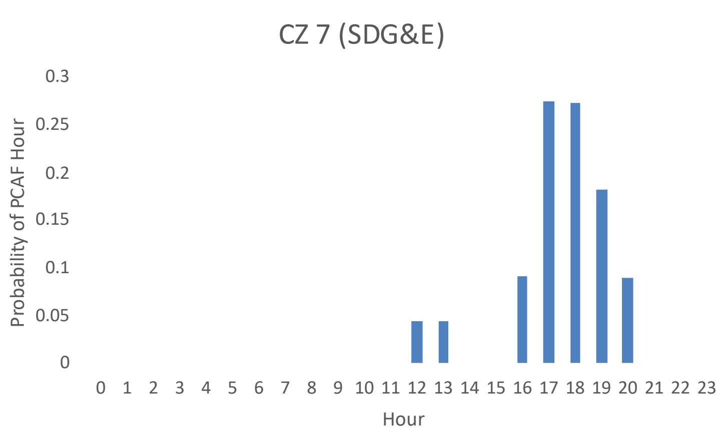


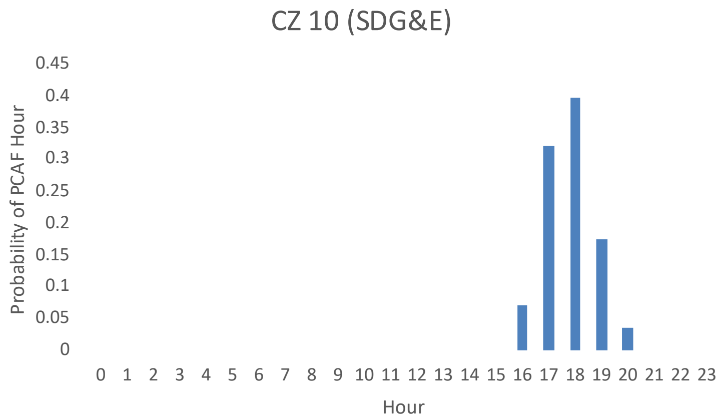
12.5.3 SDG&E PCAFs

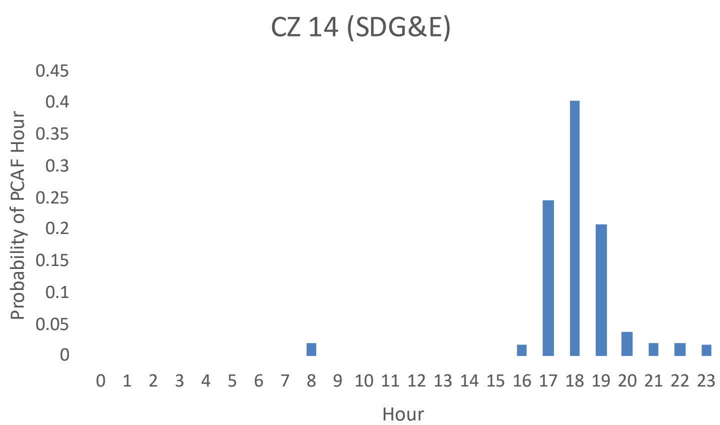
SDG&E does not produce PCAFs or PLRFs in its GRC proceedings. The consultant therefore calculated PCAFs for the SDG&E climate zones using 2023 distribution-level power flow data provided by SDG&E and the PCAF methodology as described in Section 6.3. The allocation factors are derived with the formula below and the additional constraint that the peak period contain between 20 and 250 hours for the year.

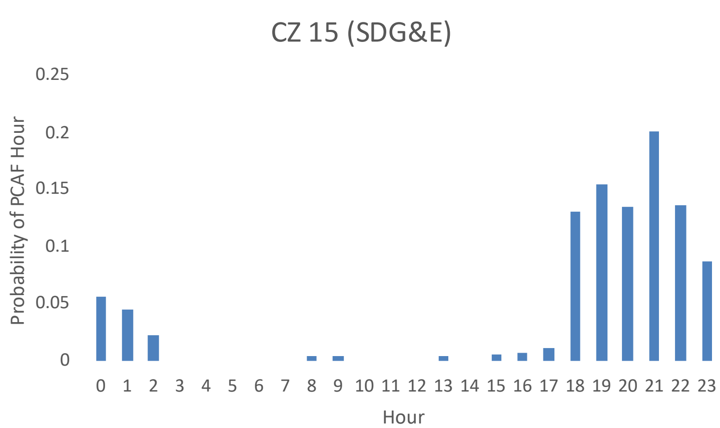
PCAF[a,h] = (Load[a,h] – Threshold[a]) / Sum of all positive (Load[a,h] – Threshold[a])

- Where:
    - a is the climate zone area,
    - h is hour of the year,
    - Load is the net distribution load, and
- Threshold is the area maximum demand less one standard deviation, or the closest value that satisfies the constraint of between 20 and 250 hours with loads above the threshold.
- SDG&E PCAFs by climate zones are shown below.









Note: The PCAFs for Climate Zone 15 show significant variation due to a much smaller total load present in SDG&E's territory within this zone. This results in small MW changes for certain hours having a greater proportional impact and more hours occurring in the peak period.

12.6 AGIC Data

12.6.1 PGE

Table 2: Gas Infrastructure Cost Estimates	Existing Subdivision/Development			New Subdivision/Development		
Mainline Extension Includes: Material & Labor Excludes: Trenching, allowances to developer or customers	Not Applicable			Single Family	21	$/ft
				Multi- Family	22	$/ft
				Non Residential	46	$/ft
Service Extension (1" pipeline from mainline to meter) Includes: Materials & Labor, Trenching (developed for exciting and undeveloped for greenfield) Excludes: Allowances Credited to Customer or Developer	Including Trenching Costs	8577	$/Svc	Including Trenching Costs	212	$/Svc
	Excluding Trenching Costs	3467	$/Svc	Excluding Trenching Costs	84	$/Svc
Meter (Including manifold outlet, where applicable)	Residential Single Family	468	$/Meter	Residential Single Family	577	$/Meter
	Residential Multi-Family	445	$/Meter	Residential Multi-Family	559	$/Meter
	Small/Medium Commercial	1384	$/Meter	Small/Medium Commercial	605	$/Meter
	Large Commercial	1384	$/Meter	Large Commercial	605	$/Meter

Note: Commercial meter costs are not disambiguated between large commercial and small/medium commercial in this summary. See "DER-CustomerPrograms_DR_ED_002-Q001Atch01" for methodology.

12.6.2 SoCalGas

Table 1: SoCalGas Gas Infrastructure Cost Estimates*		
	Existing Subdivision / Development	**New Greenfield Subdivision / Development**
Mainline Extension Includes: Material & Labor Excludes: Trenching, allowances to developer or customers	N/A It is assumed that new construction in an existing subdivision will not require a mainline extension.	Single Family $30.82/ft (2021 $) Multi-Family $30.82/ft (2021 $)
Service Extension (1" pipeline from mainline to meter) Includes: Materials & Labor, Trenching (developed for exciting and undeveloped for greenfield) Excludes: Allowances Credited to Customer or Developer	Including Trenching (Developed Area) $7,620/building (2021 $) Excluding Trenching $7,620/building (2021 $)	Including Trenching (Greenfield, Undeveloped) $7,620/building (2021 $) Excluding Trenching $7,620/building (2021 $)
Meter (Including manifold outlet, where applicable)	Residential Single Family $489 per meter (2021 $) Residential Multi-Family $330 per meter (2021 $) Small/Medium Commercial $330 per meter (2021 $) Large Commercial $13,184 per meter (2021 $)	Residential Single Family $489 per meter (2021 $) Residential Multi-Family $330 per meter (2021 $) Small/Medium Commercial $330 per meter (2021 $) Large Commercial $13,184 per meter (2021 $)

* Notes to Table 1:

1. Where applicable, SoCalGas is providing the best-available data from its 2024 Cost Allocation Proceeding (CAP) filing https://www.socalgas.com/sites/default/files/Chapter-9.pdf, providing data that correlate as closely as possible to the values requested by Energy Division.
2. SoCalGas does not track projects based on existing vs. greenfield development for its CAP workpapers – numbers are provided for new construction as a bundled category.

12.6.3 SDGE

Table 2: SDG&E Gas Infrastructure Cost Estimates*

	Existing Subdivision / Development	New Greenfield Subdivision / Development
Mainline Extension Includes: Material & Labor Excludes: Trenching, allowances to developer or customers	N/A It is assumed that new construction in an existing subdivision will not require a mainline extension.	Single Family $38.69/ft (2021 $) Multi-Family $38.69/ft (2021 $)
Service Extension (1" pipeline from mainline to meter) Includes: Materials & Labor, Trenching (developed for exciting and undeveloped for greenfield) Excludes: Allowances Credited to Customer or Developer	Including Trenching (Developed Area) $3,357/building (2024 $) Excluding Trenching $3,357/building (2024 $)	Including Trenching (Greenfield, Undeveloped) $3,357/building (2024 $) Excluding Trenching $3,357/building (2024 $)
Meter (Including manifold outlet, where applicable)	Residential Single Family $281 per meter (2024 $) Residential Multi-Family $281 per meter (2024 $) Small/Medium Commercial $281 per meter (2024 $) Large Commercial $8,012 per meter (2024 $)	Residential Single Family $281 per meter (2024 $) Residential Multi-Family $281 per meter (2024 $) Small/Medium Commercial $281 per meter (2024 $) Large Commercial $8,012 per meter (2024 $)

* Notes to Table 2:

1. Where applicable, SDG&E is providing the best-available data from its 2024 CAP https://www.socalgas.com/sites/default/files/Chapter-10.pdf, providing data that correlate as closely as possible to the values requested by Energy Division.
2. SDG&E does not track projects based on existing vs. greenfield development for its CAP workpapers and therefore numbers are provided for new construction as a bundled category.

12.7 DER ACC Model Files

DER ACC model files are available at:

- https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm , and
- https://www.ethree.com/public_proceedings/energy-efficiency-calculator/, and

- https://willdan.box.com/v/2024CPUCAvoidedCosts

File	Description
CPUC 2024 ACC Documentation	This document. PDF summary of DER ACC inputs, assumptions and methods
ACC Electric Model	8,760 hourly Avoided Costs for electricity
ACC Gas Model	Avoided costs for natural gas
ACC SERVM Prices	SERVM production simulation model results and scarcity pricing adjustments
ACC Integrated Calculation Inputs	Inputs for the Integrated Calculation of GHG and generation capacity avoided costs
ACC CPUC Integrated Calculation Model	Integrated Calculation Model zip file with pre-loaded inputs and results for TRC and SCT

12.8 Revision Log

12.8.1 List of Major Updates for 2024 ACC v1a

General

- Used IRP 2023 PSP portfolio to develop avoided costs
- Updated utility WACC
- Developed avoided costs for SCT

GHG

- Used Integrated Calculation to derive GHG avoided costs

SERVM Prices and Implied Heat Rate

- Updated the SERVM prices forecast
- Used SERVM ORDC scarcity adjustment
- SERVM directly outputs regulation up, regulation down and spinning prices

Generation

- Used Integrated Calculation to derive annual generation capacity avoided costs
- Updated capacity allocation factors with new storage dispatch

Transmission

- Calculated new transmission PCAFs based on 2023 CAISO load data for each utility
    - Remapped transmission PCAFs using 2023 weather data
- Updated Marginal Transmission Capacity Costs for SCE and SDG&E based on IEPR load forecasts and utility transmission planning data

Distribution

- No change to Long Term Marginal Distribution Capacity Costs – these will be updated with the next cycle of utility GRC Phase II filings
- Updated Near Term Marginal Distribution Capacity Costs using 2023 GNA and DDOR filings and accompanying project cost inputs provided by the utilities
    - Refined calculations to better align with 2019 T&D White Paper Methodology and accommodate new data by isolating circuits with load-increasing and load-reducing DER impacts
- Updated distribution PCAFs for SDG&E and remapped to 2018 calendar year for all utilities

Refrigerant Calculator

- Removed Refrigerant Calculator

Natural Gas ACC

- Developed avoided costs for SCT
- Switched to using IEPR natural gas forecasts for both near term and long term to be consistent with IRP
- Used residential building electrification costs as the basis for GHG value in the Natural Gas Avoided Costs Calculator
- Added Avoided Gas Infrastructure Costs (AGIC) as a new avoided cost component

12.8.2 List of Updates for 2024 ACC v1b

General

- Updated Electric Model SCT calculation to automatically exclude cap-and-trade values to avoid potential for double counting with the Social Cost of Carbon
- Added time-of-use period results for use in the CET macros and expanded to include all years for each component
- Changed SCT discount rate from 3% nominal to 5.06% nominal

Transmission

- Updated Marginal Transmission Capacity Cost for SCE to correct for an input error within the Wildlife project LNBA calculation

Integrated Calculation Inputs

- Corrected calculation errors such as total storage charging, solar curtailment inputs and spin revenues, none of which impacted the results of the Integrated Calculation

Natural Gas ACC

- Updated selected Output labels to change based on the user's input selections on the dashboard
- Updated PG&E BB gas commodity prices
- Removed NOx emission costs in SCT since air quality adder includes NOx emission impact
- Adjusted air quality adders to scale based on appliance NOx emission rates
- Replaced SCE WACC with SoCalGas WACC