2026 CPUC Draft Avoided Cost Calculator Workshop

September 9, 2026

California Public Utilities Commission

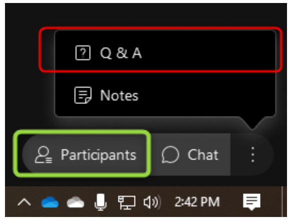
Agenda and Schedule

Topic	Presenter	Duration
Workshop Agenda and Opening Remarks	CPUC	1:30 — 1:40pm
Comparison of 2026 and 2024 ACC + discussion	E3	1:40 — 2:05 pm
Overview of SERVM data + discussion	ERM/CPUC	2:05 — 2:50pm
Integrated Calculation of Generation Capacity and GHG Avoided Costs + discussion	E3	2:50 — 3:05pm
Break		3:05 — 3:15pm
Allocation of Generation Capacity Value to LOLH Hours + discussion	E3	3:15 — 3:30pm
Transmission and Distribution Avoided Costs + discussion	E3	3:30 — 3:50pm
Closing	CPUC	3:50 — 4:00pm

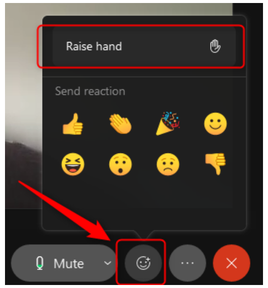
General Information

- **Please use the "raise hand" function if you want ask a question verbally and we will unmute you.**
- **Please use the Q&A function to ask questions.**
  - This leaves the chat free for general announcements
- **This workshop will be recorded and the recording and the slides will be made available.**

Q&A Panel
Lower-Right



Raise Hand
Lower-Middle



Participants Panel
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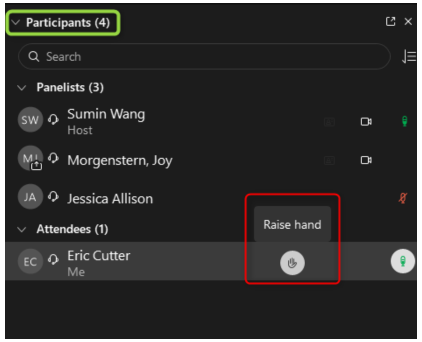

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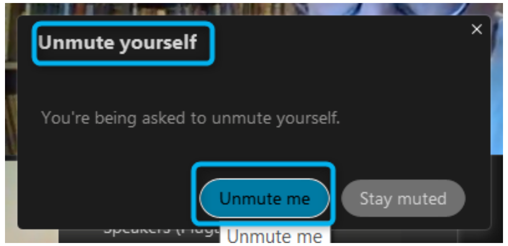
then you must click button to unmute yourself



Comparison of 2026 and 2024

TRC and SCT Avoided Costs

Energy+Environmental Economics

Reminder: Principles of Avoided Cost Framework

Marginal

Represent the costs that the utility avoids by installing a marginal unit of DER relative to the existing/planned portfolio. These costs serve as implicit and explicit price signals to achieve California's energy, reliability and climate goals.

Long-term

Represent the long-run avoided costs of a DER over its lifetime, aligning with planning expectations for meeting California's long-term goals.

Technology Agnostic

Provide a single, flexible, technology agnostic set of avoided costs that can be applied to all types of DERs.

Load Reducing | Load shifting | Load Increasing

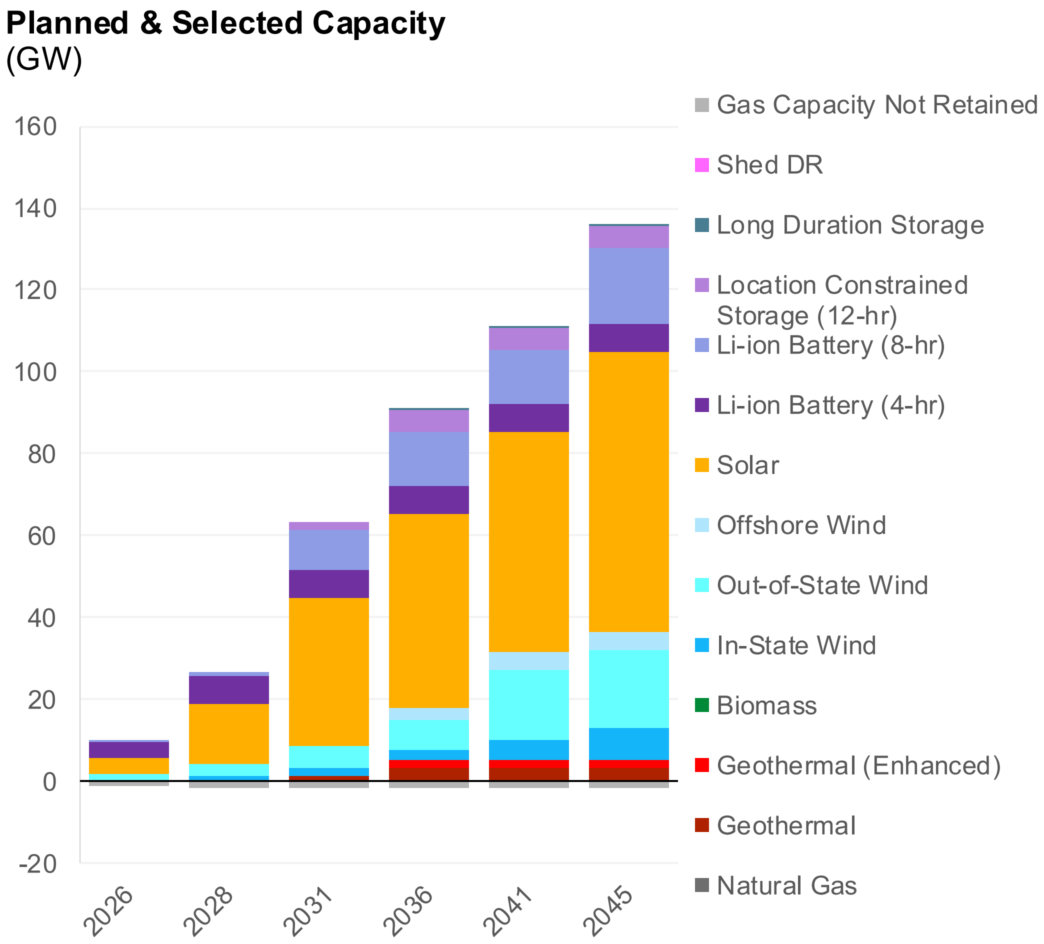
2026 ACC Methodology Update Overview

Key methodology changes for the 2026 ACC Electric and Gas Models were reviewed in detail in the 2026 ACC Staff Proposal and in the Proposed Decision Adopting Changes to the Avoided Cost Calculator mailed July 31, 2026 (R.22-11-013). These updates include:

GHG	• Adoption of a single electricity-based GHG value for both electricity and natural gas avoided cost models • Removal of the GHG rebalancing component
Capacity	• Simplified implementation of the integrated calculation for generation capacity and GHG costs • Use of Loss of Load Hours (LOLH) for calculating generation capacity allocation factors • Use of energy prices rather than temperature to allocate generation capacity value to specific days of the year • Capacity value allocation in weekdays versus weekends are aligned with loss of load modeling
Tx	• Use of load forecasts aligned with SERVM modeling to calculate transmission capacity allocation factors for future years • Use of Discounted Total Investment Method approach to calculate marginal transmission costs for all electric utilities

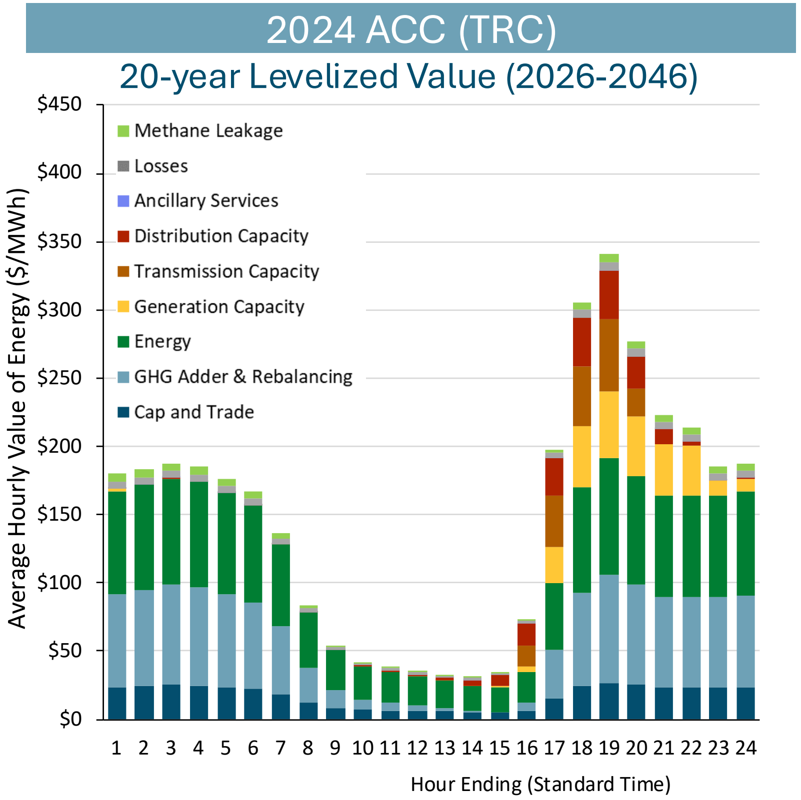
2026 ACC is based on 26-27 IRP TPP and latest utility filings

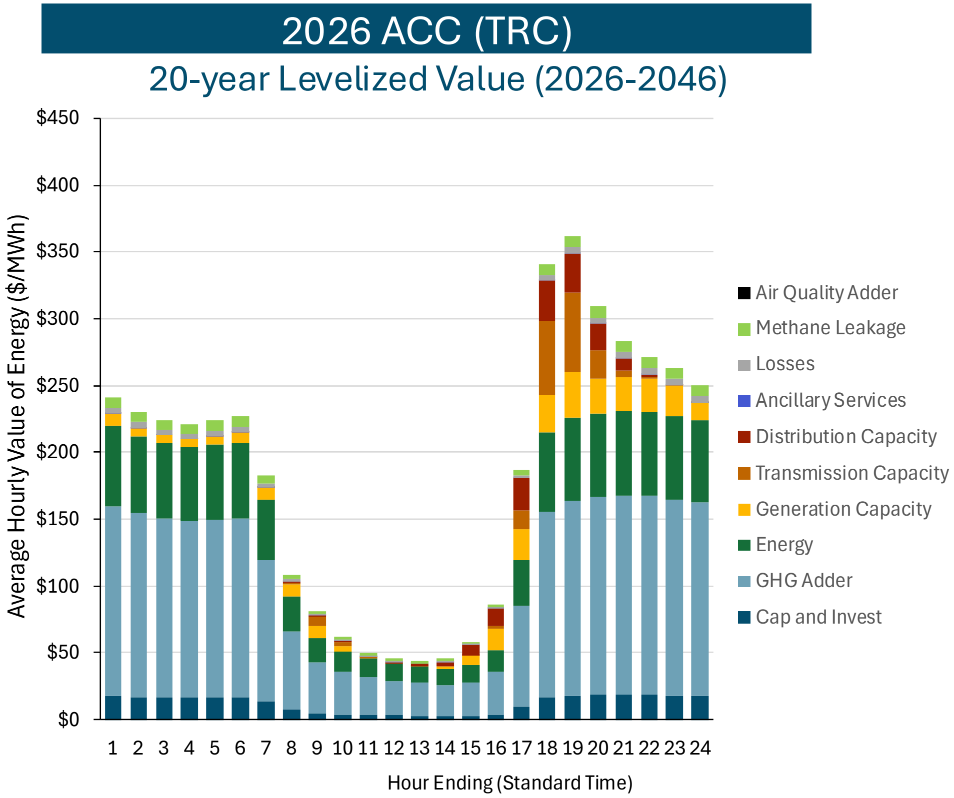
- **Energy, Generation Capacity, and GHG avoided costs are closely linked to CPUC IRP 2026-2027 Transmission Planning Process (TPP)**
  - The TPP portfolio produced by RESOLVE is simulated in SERVM to produce energy avoided costs
  - Outputs by RESOLVE and SERVM are used in the Integrated Calculation. For example: long-term cost of new solar and storage, resource energy value, marginal capacity and GHG contribution
  - General inputs such as gas price forecast and utility WACC are the same between ACC and IRP
- **Transmission and Distribution avoided costs were updated based on the latest utility General Rate Case (GRC), Distribution Upgrade Project Report (DUPR) and Grid Need Assessment (GNA) filings**



Electric ACC Values have increased since the 2024 cycle, driven by higher GHG avoided costs

- Overall values increase in early mornings and overnight
- GHG values have increased in every hour, reflecting a higher annual GHG value
- Hours of Generation Capacity and Transmission value shift later and spread across a wider window





Distribution – Slight increase

Transmission - Varied by utility

Capacity Value – Broader spread across hours

Energy Value - Decrease

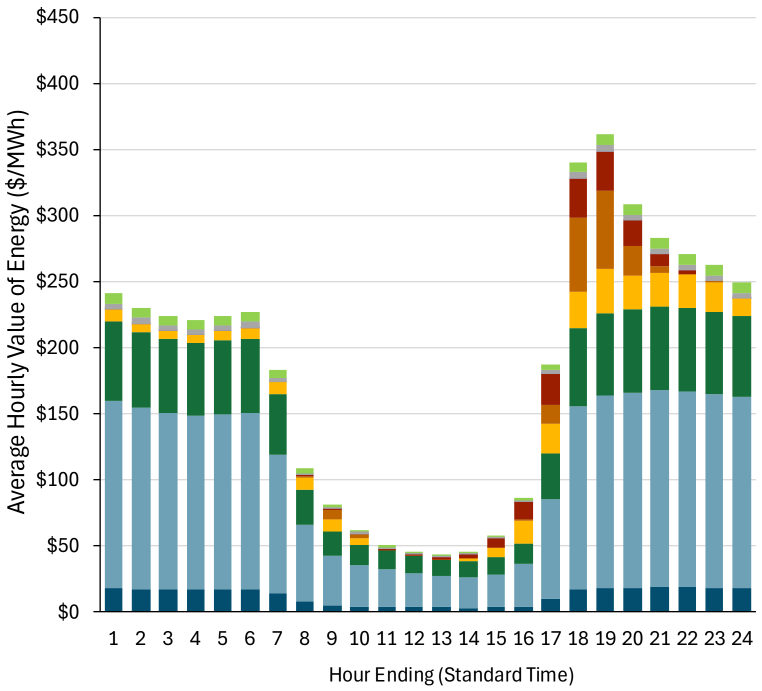
GHG Value – Significant increase

Hourly Average Avoided Costs – TRC vs. SCT

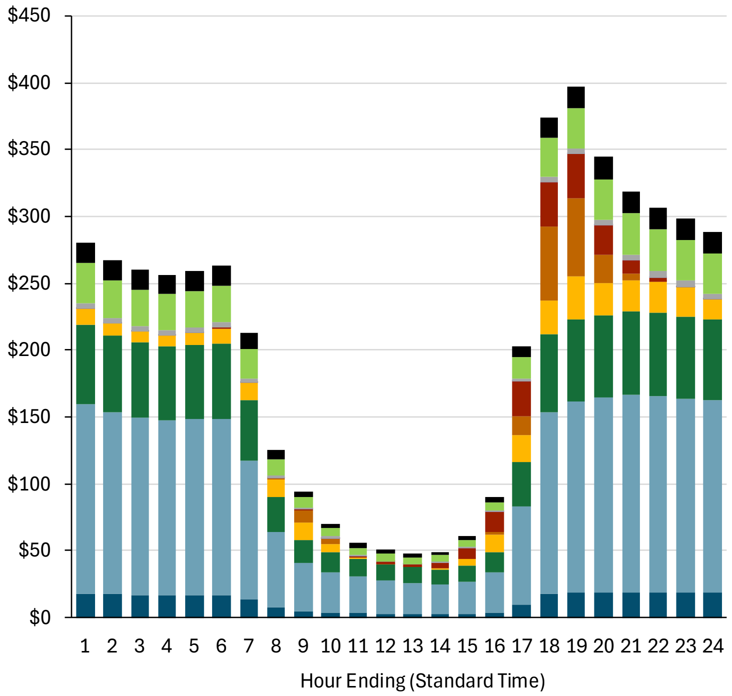
20-year Levelized Value for 2026 Resource

- Increased Methane Leakage and Air Quality Adders have most significant impact on overall avoided costs
- Adopted TRC GHG avoided costs are higher than Social Cost of Carbon (SCC) used in SCT in most years
- SCT capacity avoided costs are slightly higher than TRC due to different discount rates

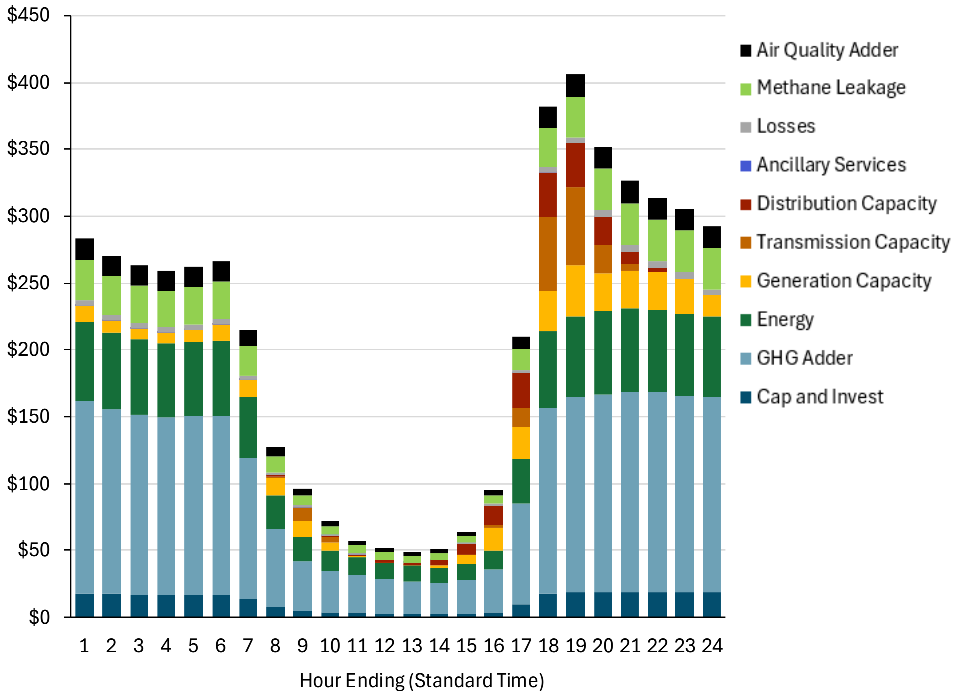
2026 ACC - TRC



2026 ACC – SCT with SCC Base



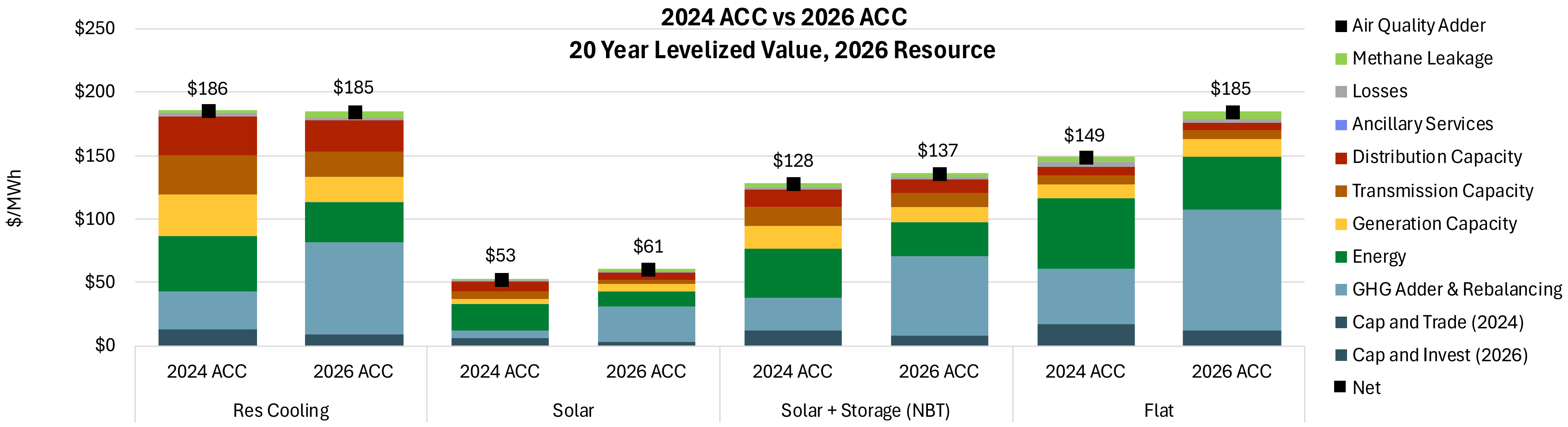
2026 ACC – SCT with SCC High



While avoided costs have increased overall, value for load reducing DERs and cooling remain in line with the 2024 ACC

- Avoided costs have increased overall due to a sharp rise in GHG costs and an increase in avoided costs during mornings and evenings
- Higher GHG value and lower energy value offset each other, resulting in similar value for solar and solar + storage

Avoided Costs of Example Load Reducing DER



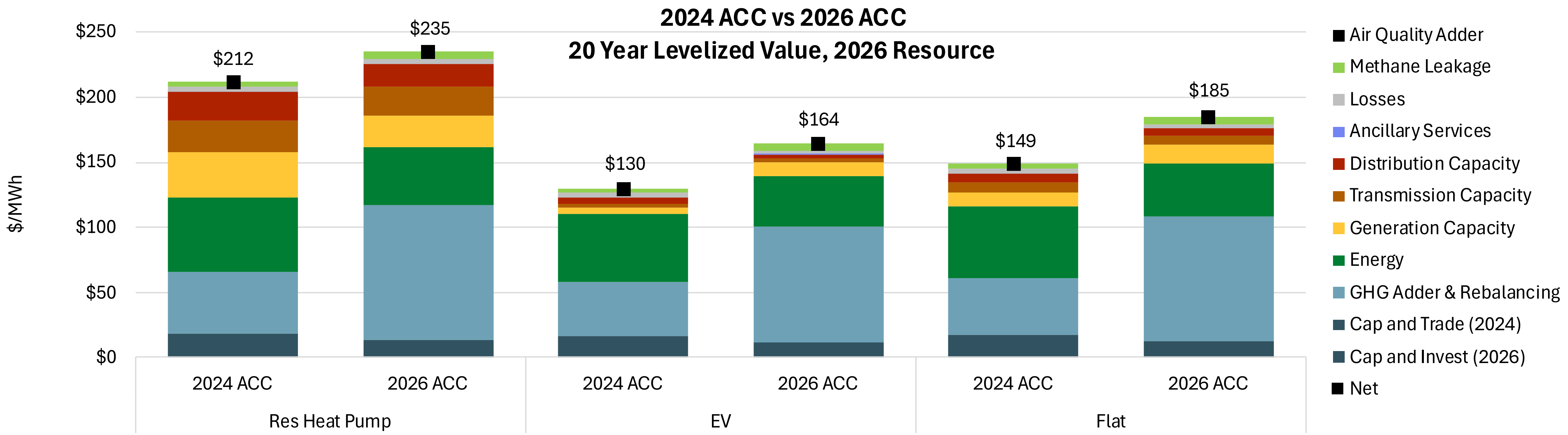
Results shown are under TRC for PG&E CZ12

Flat represents same amount of reduced load in all hours

Costs of electrification end uses have increased relative to the 2024 ACC

- Residential heating electrification has slightly higher costs due to high GHG Adder values in winter months - mitigated by low costs during the middle of the day for cooling load
- EVs have higher costs due to higher GHG Adder value in overnight and early morning hours, particularly in winter months

Marginal Costs of Example Load Increasing DERs



Results shown are under TRC for PG&E CZ12

Flat represents same amount of increased load in all hours

Natural Gas Avoided Costs have similarly increased with the adoption of the electric GHG value

+ Key methodological change for the 2026 Gas ACC: Alignment with Electric GHG value

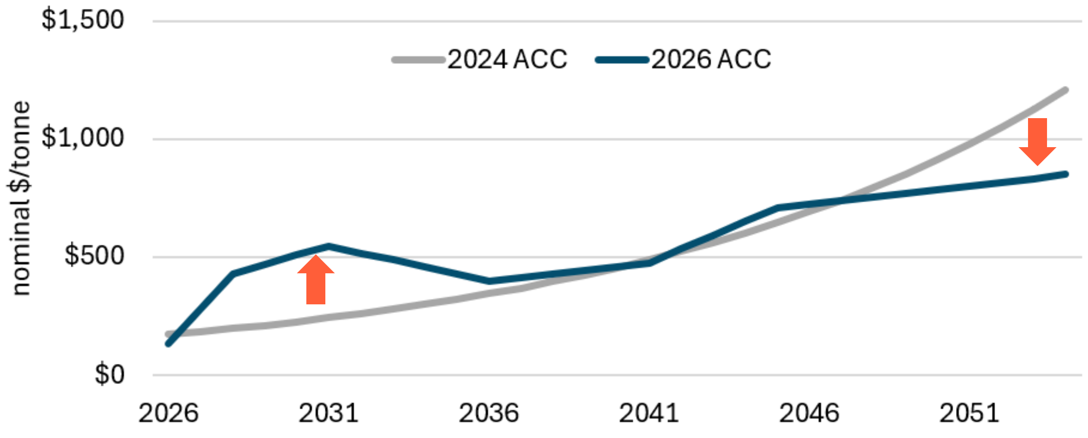
- Replaces an interim GHG value based on the marginal abatement cost of GHG in buildings
- Electric GHG value = GHG adder + Cap-and-Invest

+ Other Input Updates

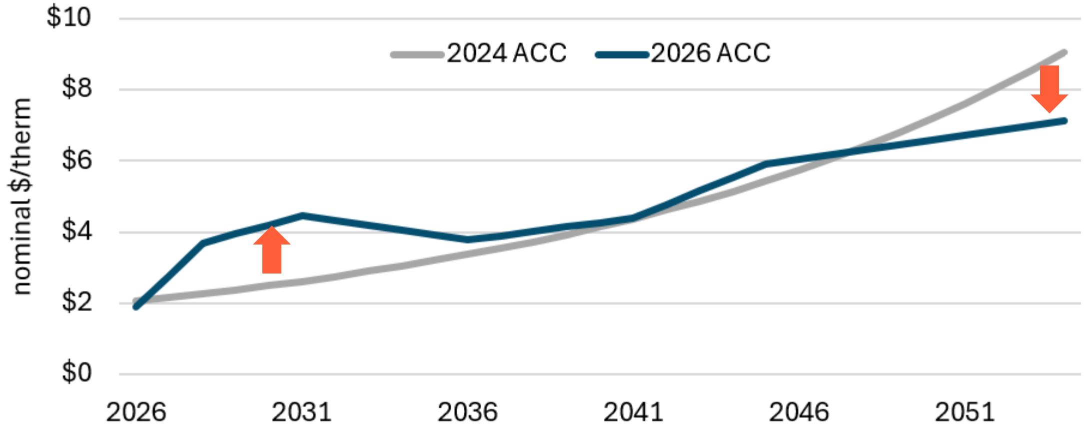
- **Avoided Gas Infrastructure Costs (AGIC)**
  - Values have increased by ~10-20%
  - PG&E's greenfield service extension costs decreased by an order of magnitude to better reflect the share of applicants completing their own trenching
- Minor shifts in gas transportation marginal costs and monthly allocation factors
- IOU WACC increased from 7.18% to 7.51%

The updated GHG value drives overall gas avoided costs higher in the near term and lower in the long term

Gas GHG Value

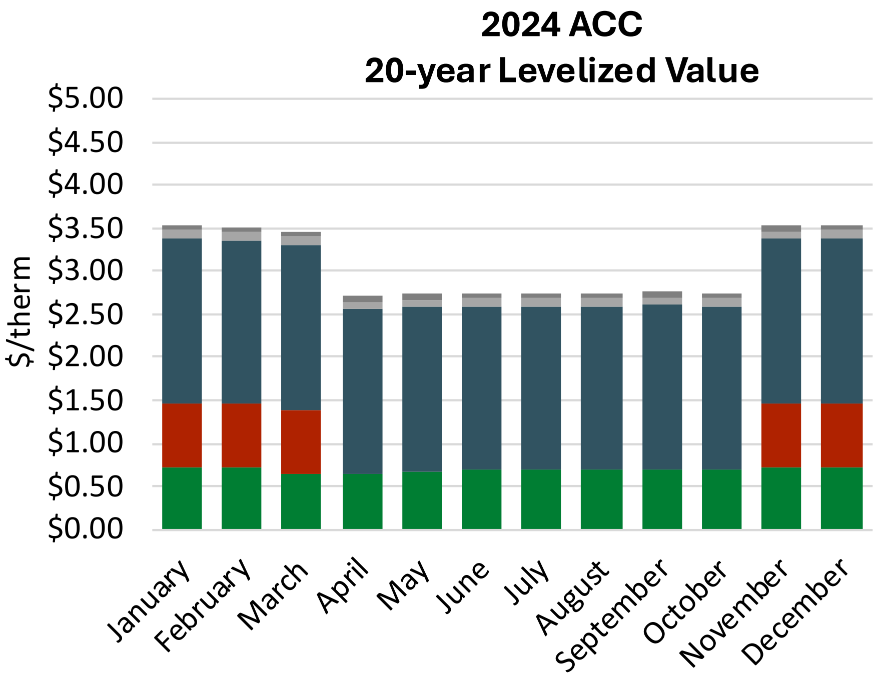


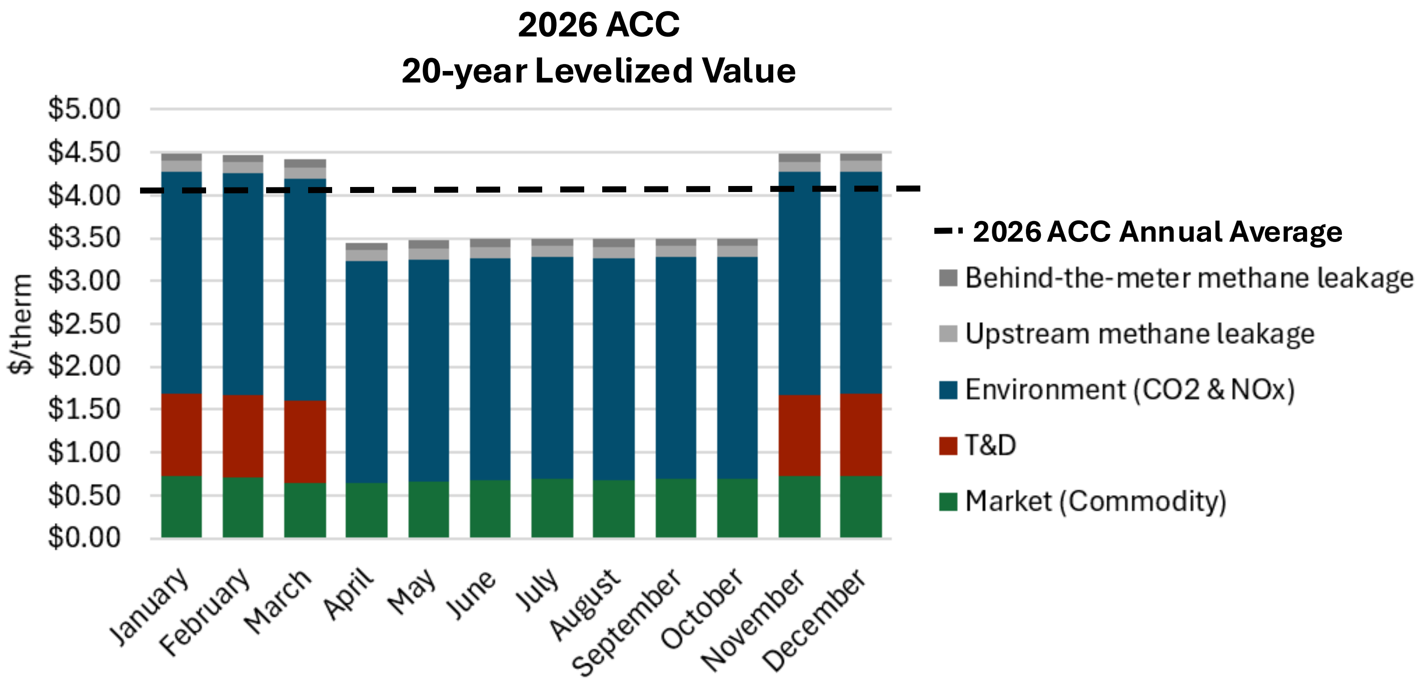
Gas Annual Average Avoided Cost



Gas Avoided Costs have increased compared to 2024 ACC

- Average annual gas avoided costs have increased compared to 2024 ACC, driven by higher GHG value
- Summer and winter allocations remain largely consistent with prior cycles

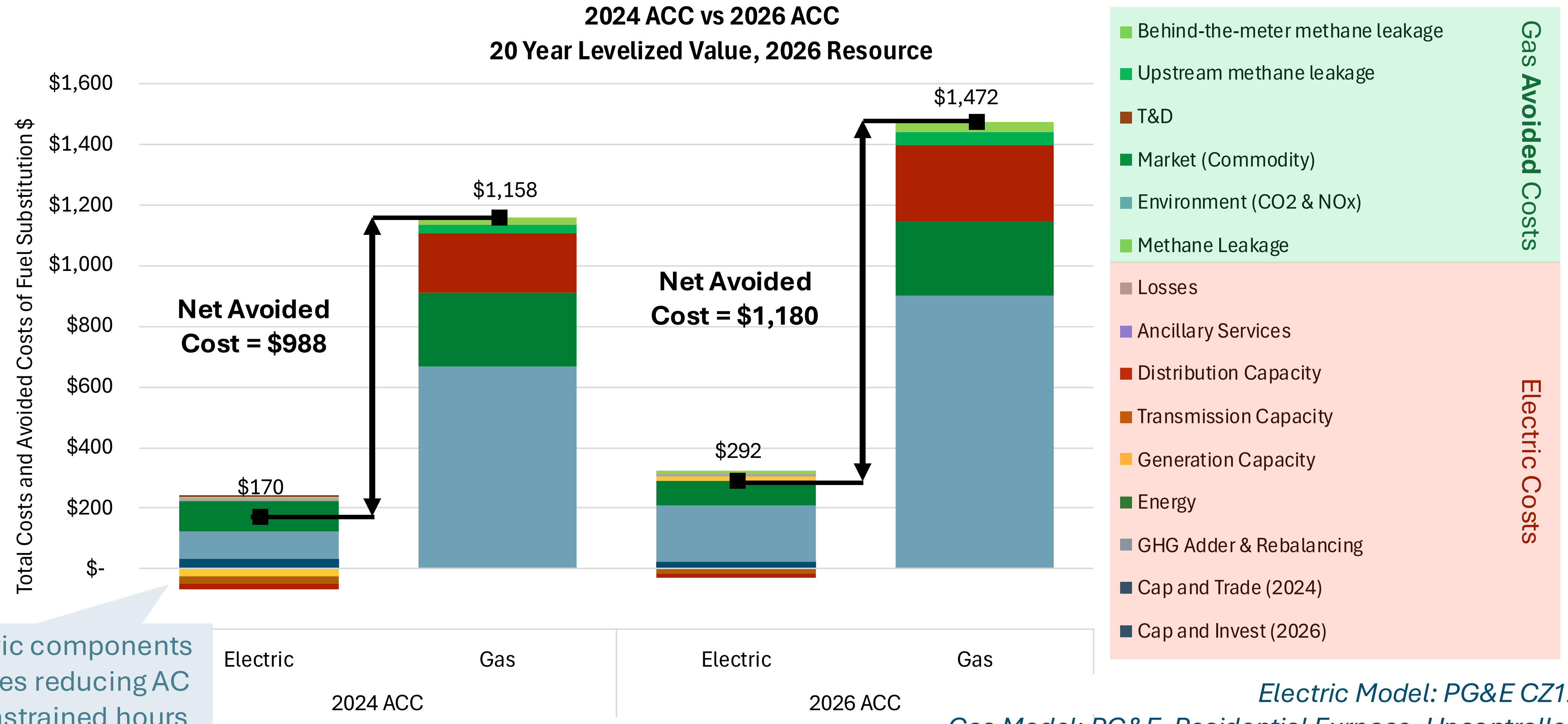




**Values shown represent 20-year levelized avoided cost for 2026 resource: PG&E, Residential Furnace, Uncontrolled*

Net avoided costs would increase from 2024 ACC to 2026 ACC for an example heat pump measure

Gas avoided costs and electric costs of example Heat Pump HVAC and Heat Pump Water Heater combined measure



Negative electric components reflect measures reducing AC use during constrained hours

Electric Model: PG&E CZ12
Gas Model: PG&E, Residential Furnace, Uncontrolled

SERVM Results

Energy+Environmental Economics

Energy Division Modeling for ACC

Backcasting and Calibration
Energy Price and Reliability Modeling

Energy Division Modeling Team

Donald Brooks

Mounir Fellahi

Overview of Presentation

1. Objectives and Background
2. Summary of Results
3. Backcasting – Methodology and Results
    1. SERVM Model Changes, Dataset Updates, and Data Preparation
    2. Methodology
    3. Results and Updates to Increase Calibration
4. Energy Pricing Forecasts
    1. Energy Pricing Forecasts – Inputs and Assumptions
    2. Methodology Review
    3. Energy Pricing – Forecast Results
5. Reliability Metrics Methodology and Results
    1. Reliability Modeling Methodology and Energy Equity
    2. Results - Loss-of-Load Magnitude and Expected Unserved Energy
    3. Loss-of-Load Frequency
6. Conclusion

Objectives and Background

Objectives of Avoided Cost Analysis

- Energy Division Staff (Staff) performed modeling to support the Avoided Cost Calculator (ACC) to estimate the avoided energy price and reliability costs that could be offset by increased development of Distributed Energy Resources (DERs) or costs created by increased demand from fuel switching and electric vehicles.
- Staff used a production cost modeling framework and a dataset created for the Transmission Planning Process (TPP) to simulate how the CAISO market would realistically operate. Simulating a typical weather scenario and typical dispatch in the CAISO market would provide the counterfactual energy prices that would happen in the absence of new DERs and new electric demand, across the hours of the day and months of the year.
- Staff simulated CAISO prices and dispatch for each year from 2027 through 2040, and also simulated 2045.
- Staff produced Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) results for the CAISO regions for 2027, 2031, 2036, and 2041.

Overview of Modeling Phases

Energy Division Staff performed modeling in three phases to update the ACC according to the Biennial ACC cycle

Staff did the following:

- **Backcasting**: Compared the energy prices and energy dispatch patterns resulting from SERVM model to actual 2022 and 2023 CAISO historical energy price data and energy dispatch patterns in order to identify corrections we can make to SERVM to make our results closer to CAISO historical market performance. This step is important to increase credibility in our results and to identify pricing and dispatch effects that can increase fidelity in our modeling to match reality.
- **Energy Price Forecasts**: Using corrections identified in Backcasting, use the current IRP portfolio for TPP in SERVM to forecast expected energy price and dispatch patterns over 2027 to 2045
- **Reliability Forecast:** Forecast reliability Test the TPP portfolio and SERVM model to identify Loss of Load and Expected Unserved Energy in future years to determine what hours and months would generate additional capacity value in the ACC model.

Background – previous ACC cycles?

- In the previous ACC cycle, SERVM used historical weather years through 2022. This cycle adds 2023 and 2024, expanding the weather-year dataset through 2024.
- This cycle uses the 2026–27 TPP Proposed Base Case Portfolio.
- The Typical Meteorological Year (TMY) calendar changed from the previous cycle. A TMY represents typical or average long-term weather conditions rather than the weather from a single historical year. It is constructed by selecting representative months from different historical years to create a full 12-month weather year.
- In previous ACC cycles, Expected Unserved Energy (EUE) which measures the magnitude of loss-of-load events—was used to develop capacity allocation factors. In the 2026 ACC staff proposal, Loss of Load Hours (LOLH), which measures the frequency of loss-of-load events, is proposed as the basis for capacity allocation factors. This cycle, Energy Division staff provides LOLH results in addition to EUE.
- Extensive backtesting and analysis were conducted this cycle to align the dispatch with historical CAISO data.

Summary of Results

Summary of key findings

Energy Division Staff found:

Backcasting –

- Backcasting 2022 CAISO historical dispatch in our 2026 TPP dataset and comparing to previous backcasting from the previous ACC cycle is a sound basis to validate and calibrate SERVM against observed CAISO dispatch and price patterns. Backcasting for this ACC illustrates improved alignment with CAISO operating patterns relative to the prior calibration cycle, including hourly price patterns, monthly error, and the observed relationship between electric prices and gas prices.
- We have improved but not perfected our replication of the current CAISO market, and it is uncertain how the CAISO market will change in the future and how it will develop. Nevertheless, our backcasting provides a good means to improve our representation of reality.

Energy Prices –

- Applying the calibrated SERVM dataset to future TPP portfolios produces a consistent trend: greater solar and storage penetration lowers midday prices and shifts higher-price periods toward the morning and evening hours. As we move further into the future, energy prices flatten throughout the day in the spring, and annual peak energy prices occur in winter months, peaking in evening hours of January and December by 2045.

Reliability Results –

- Growing electrification and fuel-switching demand increase system needs throughout the year, and energy demand is less connected to peak summer heat. The occurrence of reliability risk shifts across the forecast horizon—from late-summer afternoon and evening hours largely in Southern California currently to also seeing increased winter morning risk in PG&E territory by 2041. Winter risk is more connected to demand increases like EV and electrification that are not dependent on high summer heat and are more spread throughout the year.

Key Takeaway -

- Overall backcasting and calibration to CAISO dispatch and price patterns provide a more credible foundation to forecast future energy price, dispatch, and reliability needs. While our modeling is still improving, this is a credible framework to create avoided energy and reliability costs for the ACC.

Backcasting-Methodology and Results

Methodology and Data Updates

Key SERVM Model Updates

The relevant upgrades to the SERVM model since 2024 ACC are listed and briefly described below:

- SERVM was configured to reschedule up to 20 percent of generator maintenance around extreme weather events, to avoid unnecessarily causing reliability problems in winter months in future years. This reflects some ability for CAISO to reschedule maintenance around week-ahead weather that may increase peak demand .
- Import constraint assumptions were ramped during the hours ending 17 through 22 by adding 3 steps of 6,330 MW, 4,000 MW, and 8,660 MW, to avoid the sudden change from 11,040 MW down to 4,000 MW, which caused unrealistic dispatch patterns .
- SERVM's storage dispatch logic was revised to operate storage more efficiently and better align with RESOLVE's storage dispatch .
- Option to use Energy Equity Analysis.
- Staff updated several datasets, including adding 2023 and 2024 weather years to our weather representation and updating to the latest generator resource baseline to represent the adopted 2026-27 TPP portfolio.

Backcasting Methodology

- Staff performed backcasting to compare to our previous backcasting in 2024. Staff benchmarked and quantify improvement.
  - Staff gathered actual dispatch and pricing data
  - Staff constrained SERVM to take as fixed inputs the fuel, GHG, electric demand, solar, wind and import profiles then forced the dispatchable fleet to dispatch around those constraints to meet hourly demand
  - Staff assessed dispatch by resource type, compared to CAISO actual dispatch
  - Staff analyzed resulting energy prices from SERVM and compared to CAISO historical pricing and analyzed metrics to determine quality of backcasting
  - Staff compared backcasting metrics in this 2026 ACC Calibration to previous 2024 ACC calibration to see if this year is an improvement

Historical Data and SERVM Backtest Inputs for testing 2022

- 2022 CAISO and settlement data, including CAISO sources such as Today's Outlook and the Open Access Same-time Information System (OASIS), were used to recreate observed system conditions and benchmark SERVM performance.
- Market and system data: energy and ancillary service prices, demand, solar, wind, hydro, imports/exports, generation, and curtailment — CAISO.
- Thermal resource data: unit-level characteristics, capacity, and availability for CC, CT, cogeneration, and geothermal resources — settlement data.
- Fuel and emissions: historical daily natural gas prices, CAISO fuel prices, and GHG allowance prices — CAISO and Natural Gas Intelligence (NGI).
- Historical data were processed into hourly inputs directly comparable with SERVM outputs. Gas prices were mapped to generating units, and energy prices excluded congestion and transmission losses.
- CAISO data were collected through APIs and processed using Python and Excel. The resulting historical inputs formed the basis for the 2022 SERVM backtest and calibration.

Backcasting Methodology and Results

Calibration and Results

Price Validation: 2026 ACC vs 2024 ACC Calibration vs CAISO Historical Dispatch

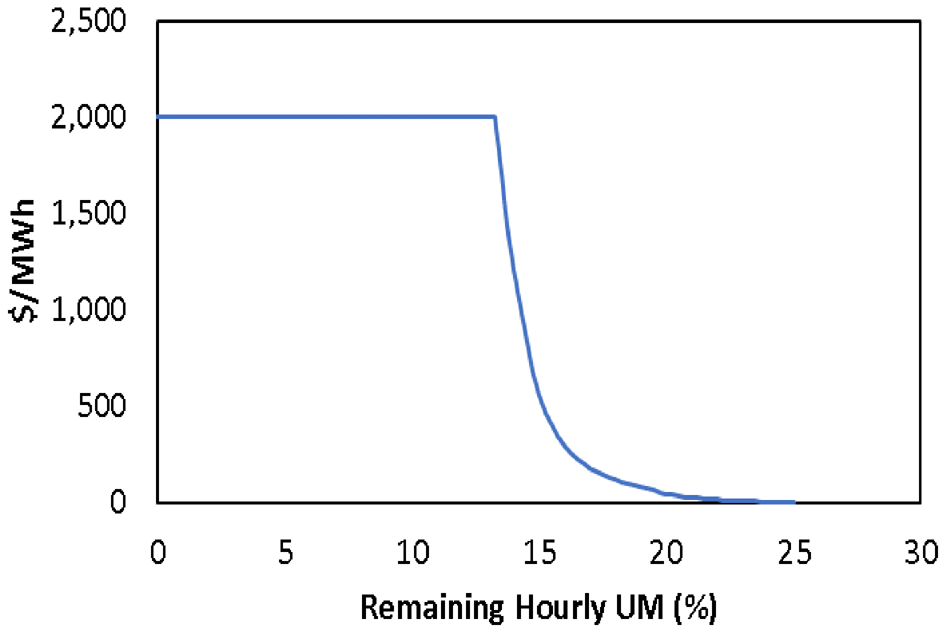
- Staff compared dispatch and price patterns by hour of day and month of year. Staff compared between the 2024 ACC calibration results and the current 2026 ACC backasting results to actual CAISO dispatch results for 2022 historical year. Staff identified improvement between 2024 and 2026 in matching CAISO historical patterns.
- Staff identified changes and updates to the SERVM dataset that improve calibration to CAISO.
- Staff compared hourly and seasonal price profiles and visually compared, as well as compared statistical metrics. These comparisons informed pricing changes to align modeling.
- Staff compared Mean Absolute Percentage Error (MAPE) from 2026 backcasting to CAISO prices and also compared MAPE results from 2026 ACC to MAPE from 2024 ACC.
- Price–gas relationship (R^2): evaluates how closely market prices are correlated to gas prices. Staff compared price to gas relationship of the 2026 ACC to the 2024 ACC and CAISO historical market prices.
- Staff showed improved calibration to CAISO historical pricing relative to 2024 ACC backcasting.

Key Updates and Changes made to SERVM dataset that improved calibration

Staff identified several changes to the SERVM dataset to improve calibration.

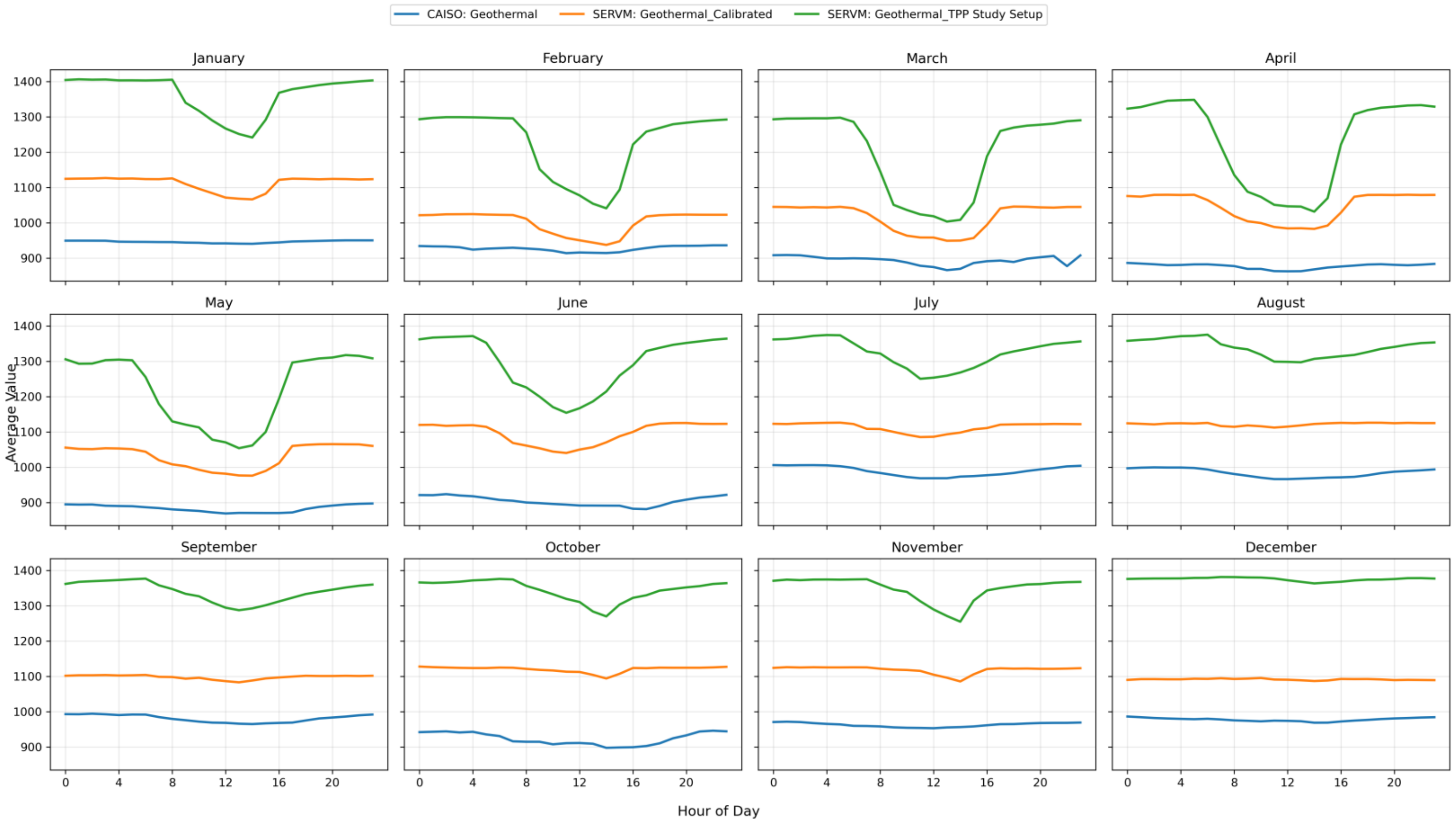
- Thermal dispatch: adjusted cogeneration and geothermal dispatch limits, price adjustments to CT resources to increase their dispatch, and curtailment cost profiles to calibrate negative pricing and curtailment patterns.
- Overgeneration pricing: refined low-price behavior during surplus-generation conditions to match CAISO patterns, set floor to match price floor from CAISO market.
- Scarcity pricing / ORDC: aligned scarcity pricing with CAISO market limits:
    - scarcity pricing rising to the $2,000/MWh hard energy bid cap
    - Chart at right shows decreasing price premiums at increasing reserve levels. As reserves decline to 15%, pricing escalates sharply.

Scarcity Pricing Curve - $/MWh at varying reserve margin percentages



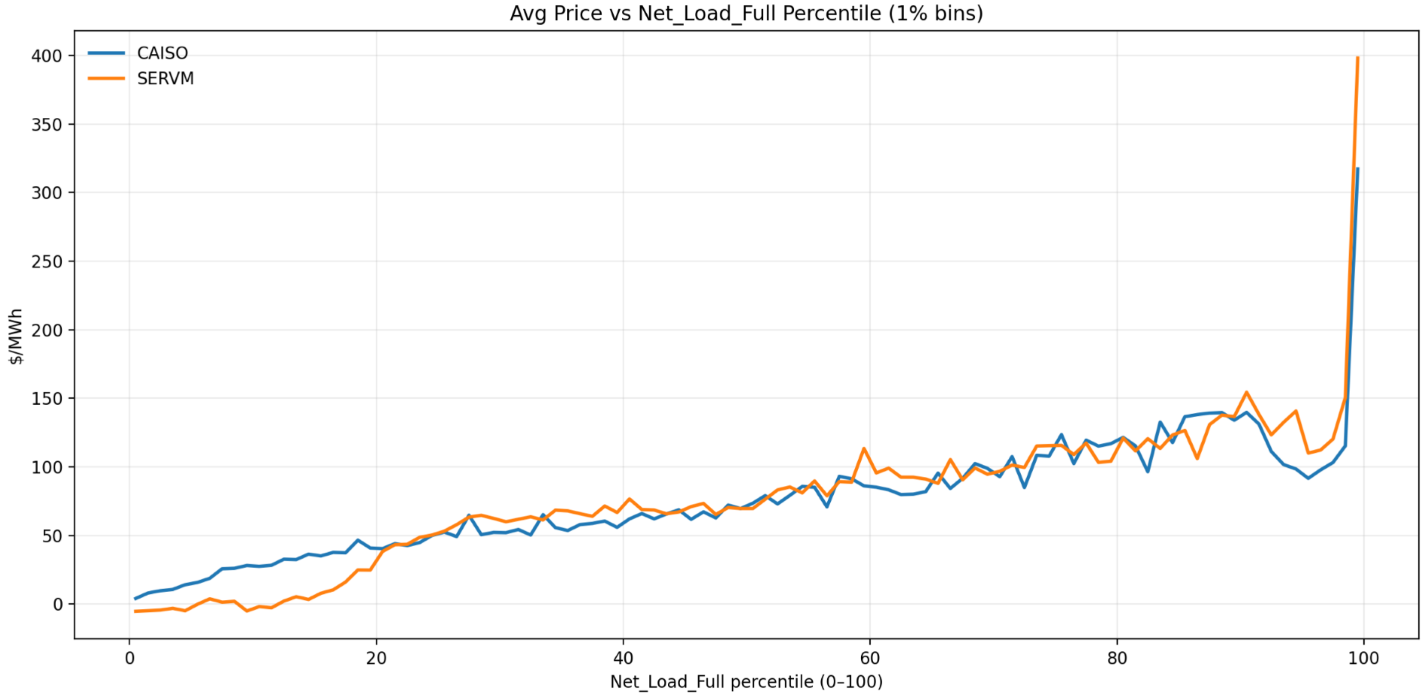
Geothermal Calibration Improved Dispatch Alignment relative to TPP portfolio

- The original TPP setup consistently over-dispatched geothermal relative to CAISO.
- Staff reduced geothermal dispatch and moved SERVM closer to observed 2022 levels across most months.



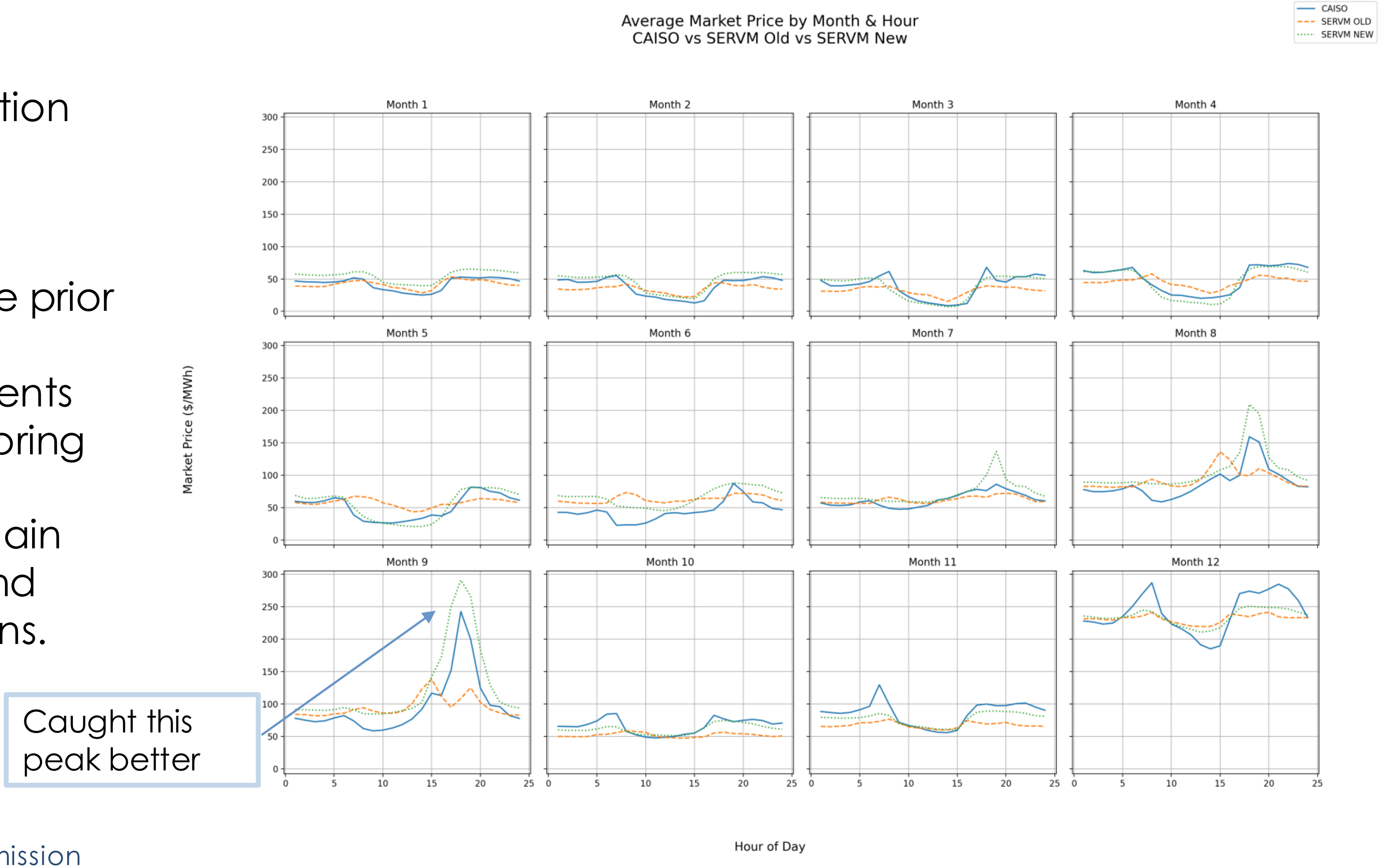
Market Prices Track CAISO Across Net Load Conditions

- SERVM reproduces the overall relationship between market prices and net load generally seen in CAISO market for 2022 though there is still come difference.
- Prices generally increase as net load rises, consistent with observed CAISO behavior.
- The calibrated model tracks CAISO closely across much of the net load distribution.
- Net Load = (Load + Pumping) − (Solar + Wind + Hydro − Curtailment) − Imports



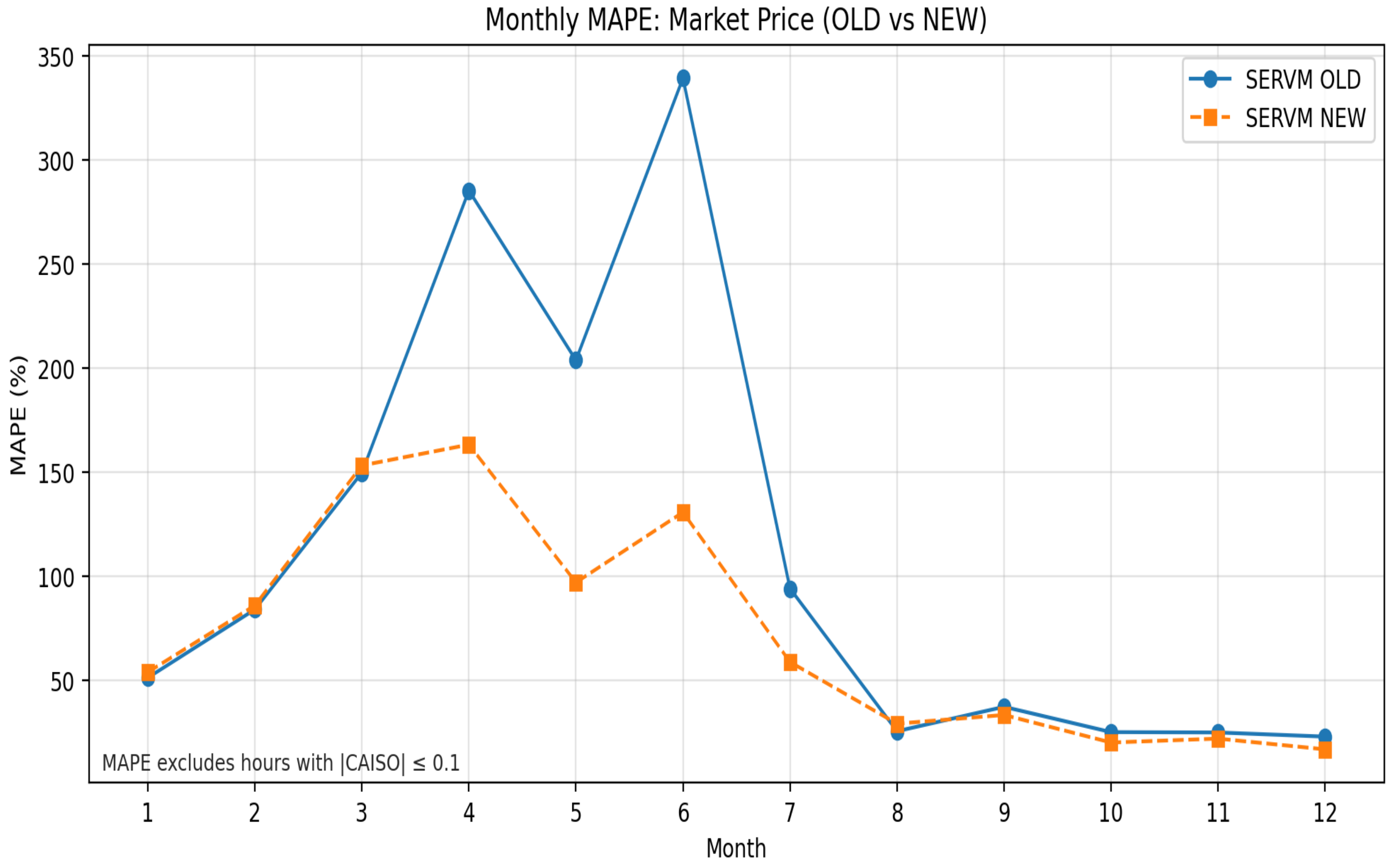
Current Calibration Improves Price Alignment with CAISO

- The 2026 ACC calibration better reproduces observed hourly and seasonal CAISO price patterns relative to the prior calibration cycle.
- The largest improvements are visible in several spring and summer months.
- Some differences remain during higher-price and low-net-load conditions.



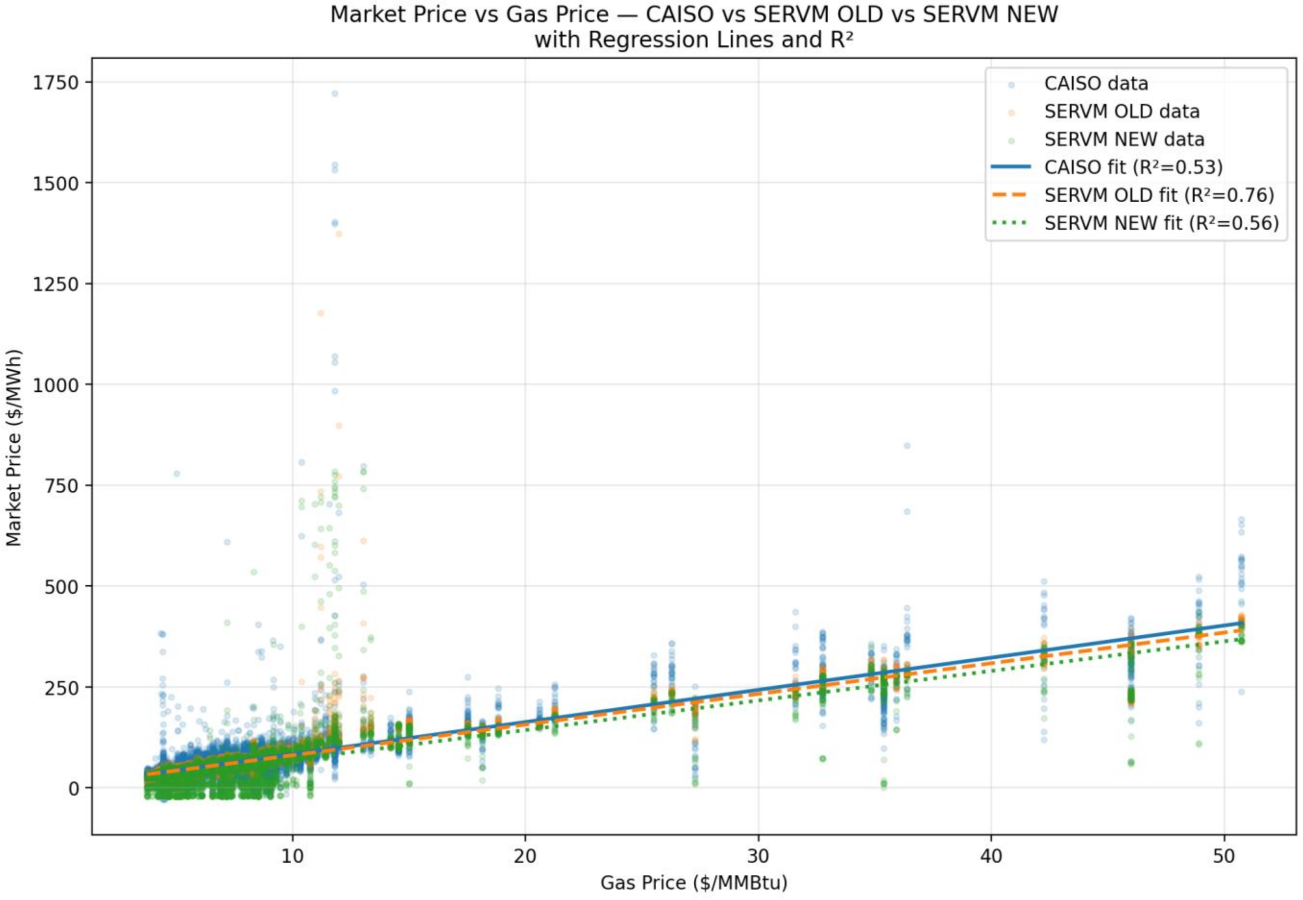
2026 ACC is better calibrated than 2024 ACC

- MAPE measures the average absolute percentage difference between SERVM results to historical CAISO prices. Lower MAPE indicates closer agreement.
- The current calibration reduces MAPE in the months with the largest errors relative to the prior calibration cycle.
- The largest reductions occur primarily from April through July.
- Months that already had relatively low error show similar performance across calibration cycles.



Current Calibration Better Matches CAISO's Price–Gas Relationship

- R^2 measures the share of variation in electricity prices explained by the linear relationship with natural gas prices. The objective is to reproduce CAISO's relationship, not maximize R^2.
- CAISO shows an R^2 approximately **0.53** between market prices and natural gas prices.
- The 2026 ACC calibration is approximately **0.56**, compared with **0.76** for the 2024 ACC calibration cycle.



Energy Pricing Forecasts

Methodology

Energy Pricing Forecasts based on previous TPP Modeling and Backcasting

Staff used a Typical Meteorological Year (TMY) approach to simplify how energy prices represent a typical year, not the full distribution of mild and extreme years. The TMY approach relies in stitching together individual months matched to weather year patterns drawn from the CZ2025 CEC TMY dataset.

Staff used the portfolio and dataset from the 2026 Transmission Planning Portfolio modeling that was adopted in February 2026.

Staff produced hourly electricity prices from 2027 through 2045. E3 took those forecasts and used them in the overall ACC model to create the ACC values through 2050.

Staff updated SERVM in line with insights provided by backcasting and calibration then produced energy price forecasts. Key updated include:

- GHG Assumptions: Mid-case GHG allowance assumptions.
- Market / Reliability Assumptions: ORDC, overgeneration penalties, and curtailment assumptions.
- Supply-Side Adjustments: Adjustments to cogeneration, geothermal, and combined-cycle (CC) resources.
- Diablo Canyon: Not retained after 2030.

Comparison of Statewide TMY Month Selection

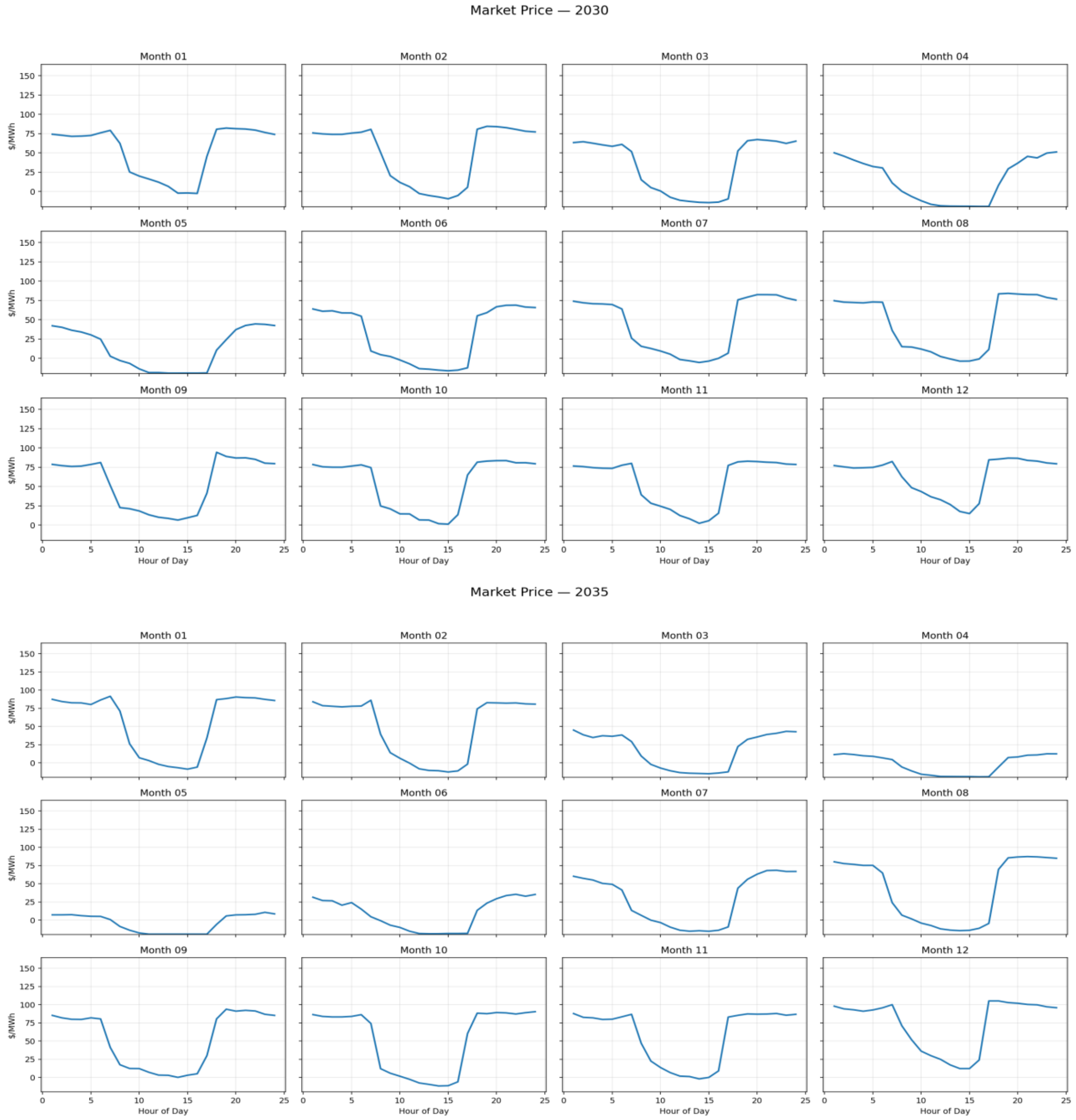
Month	2025 Historic	SSP2	SSP3
January	2011	2015	2019
February	2008	2014	2014
March	2000	2016	2016
April	2018	2018	2018
May	2017	2000	2000
June	2016	2017	2006
July	2007	2006	2006
August	2005	2015	2015
September	2016	2014	2014
October	2012	2012	2012
November	2005	2014	2016
December	2004	2018	2018

Energy Pricing Forecasts

Forecast Results

Forecast Energy Price Results: 2030 and 2035

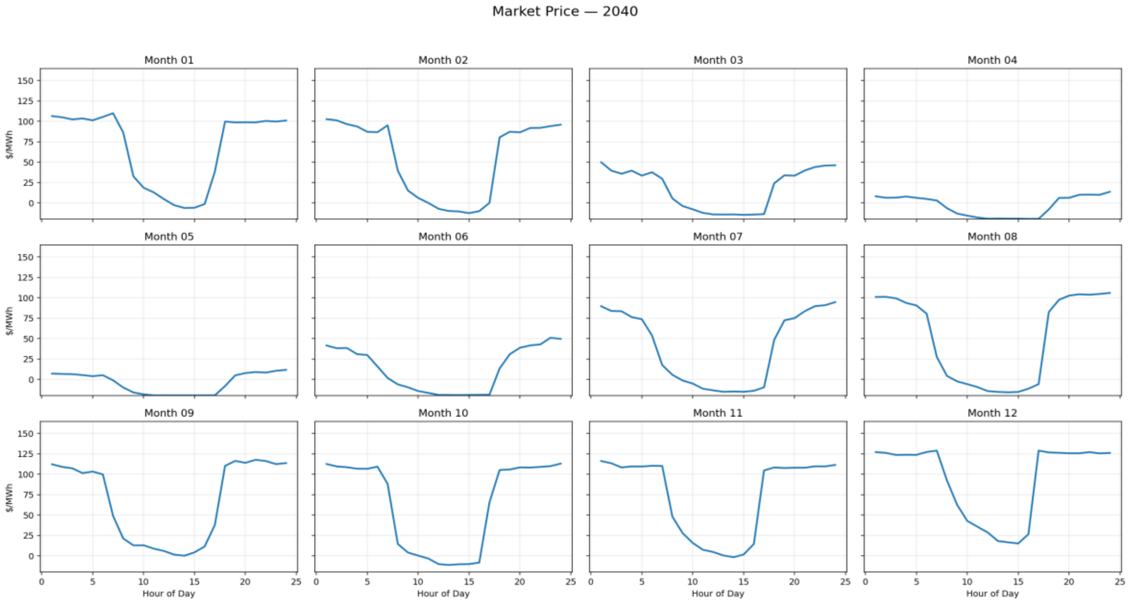
- Midday energy prices decline and remain suppressed for more hours by 2035.
- Low-price patterns become more persistent across spring and summer months.
- Morning and evening prices remain higher, reflecting lower solar output and higher net load.

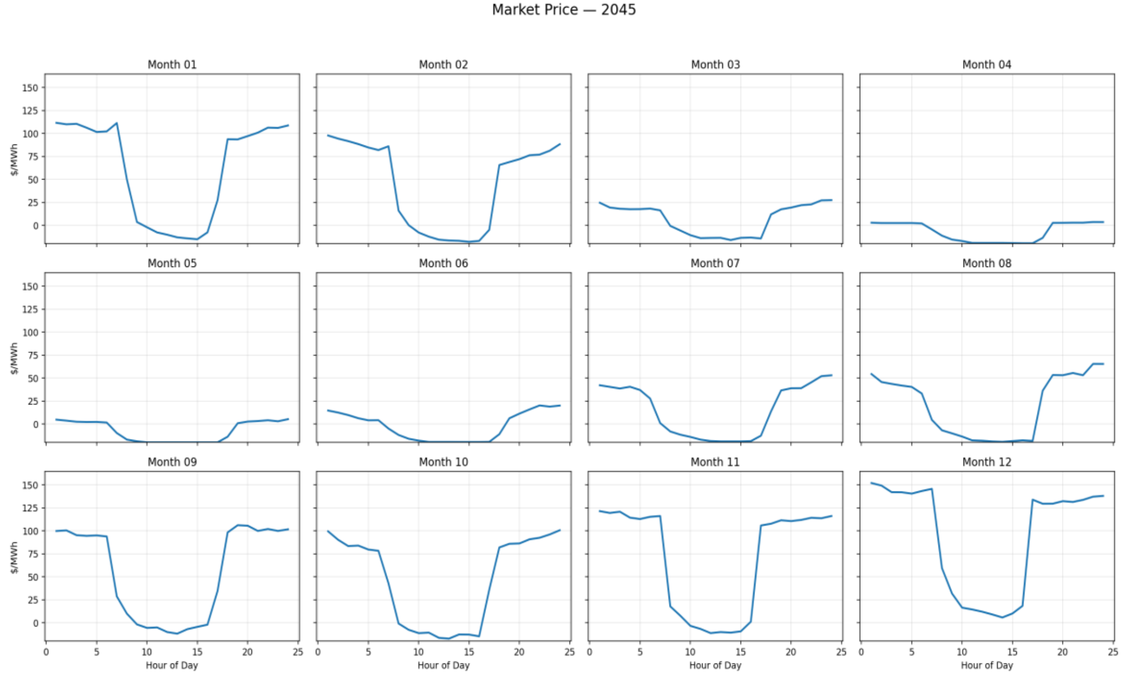


Forecast Energy Price Results: 2040 and 2045

- Midday price suppression becomes deeper and extends across the spring and early summer by 2045.

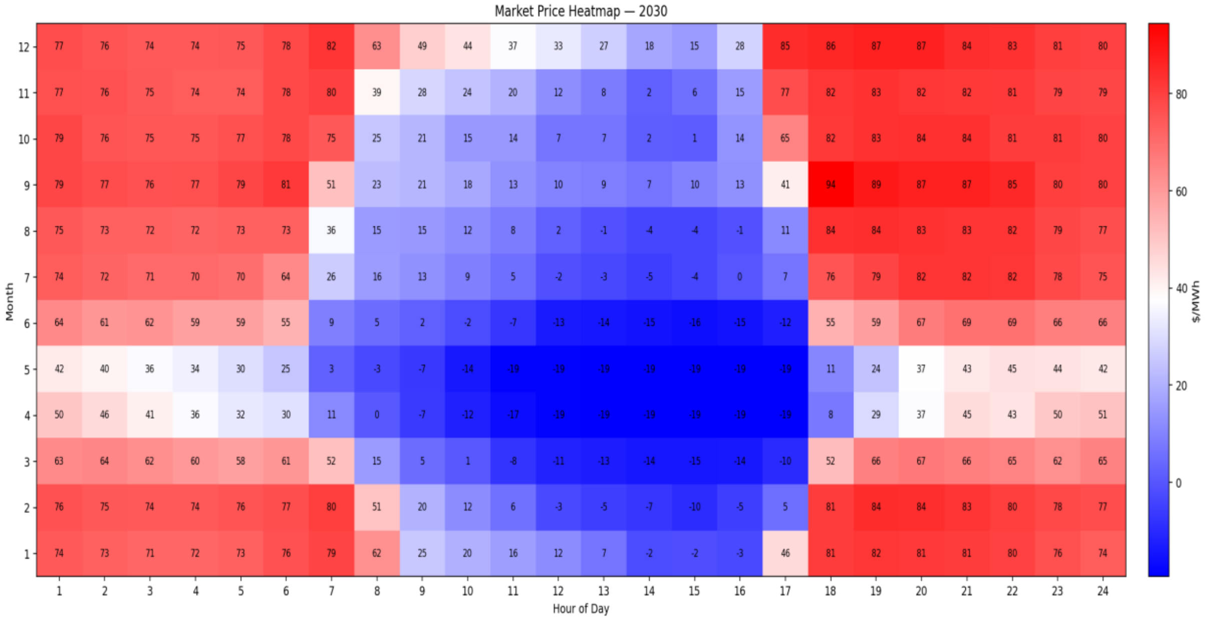
- Higher prices become increasingly concentrated in morning and evening hours.
- Prices peak in winter months as winter peak demands become more frequent

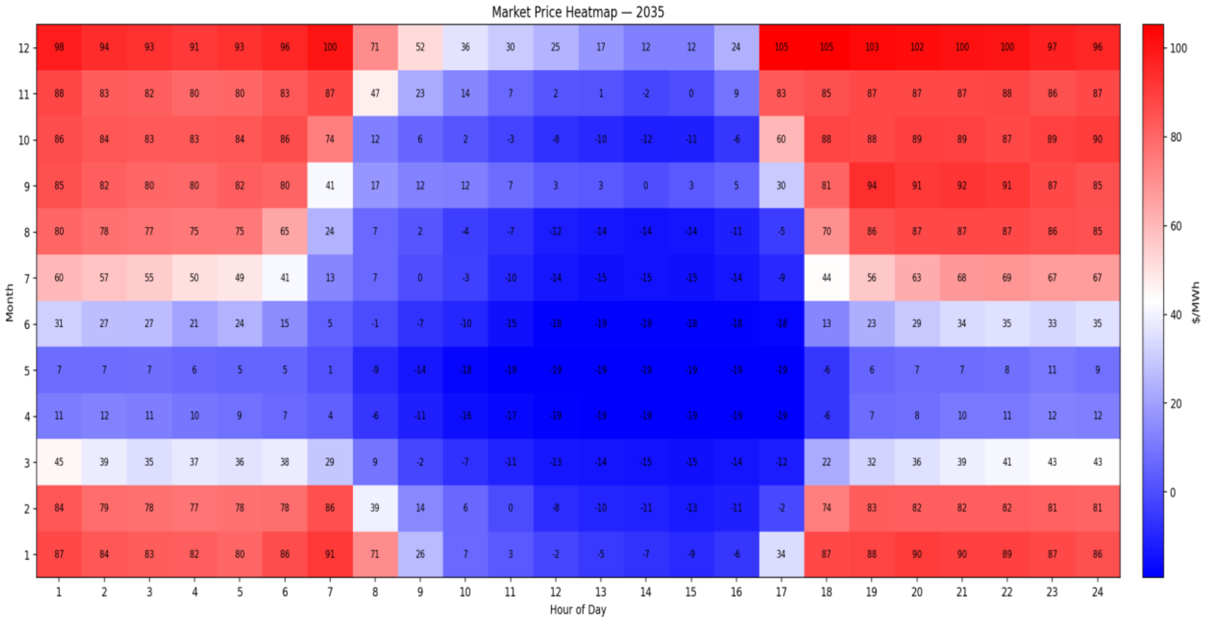




Forecast Price Heatmaps: 2030 and 2035

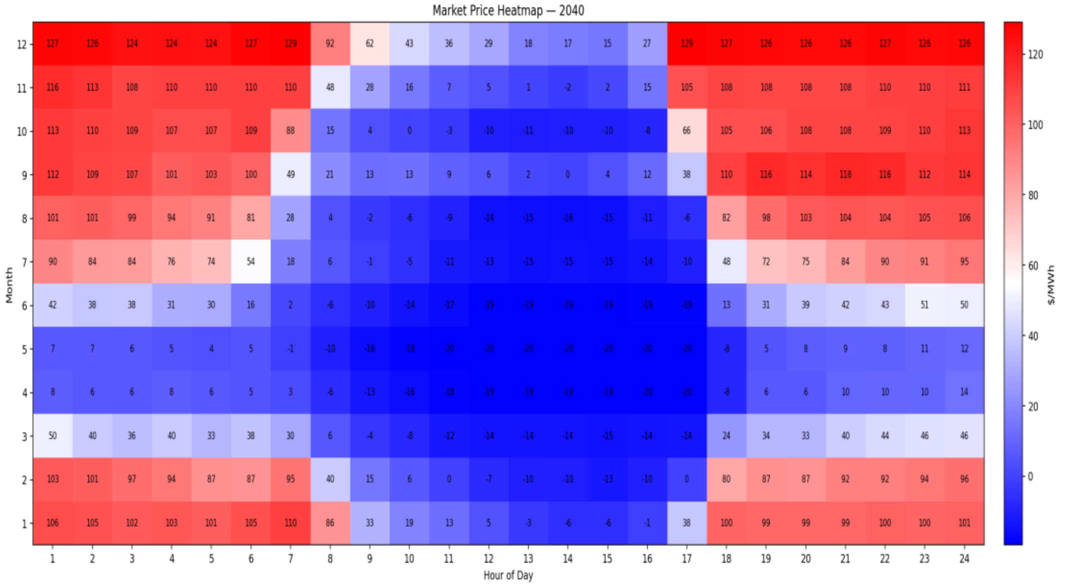
- Low-price midday hours become more pronounced across spring and summer months.
- Low-price conditions extend across more hours and months by 2035.
- Morning and evening prices remain higher as solar output declines and net load rises.

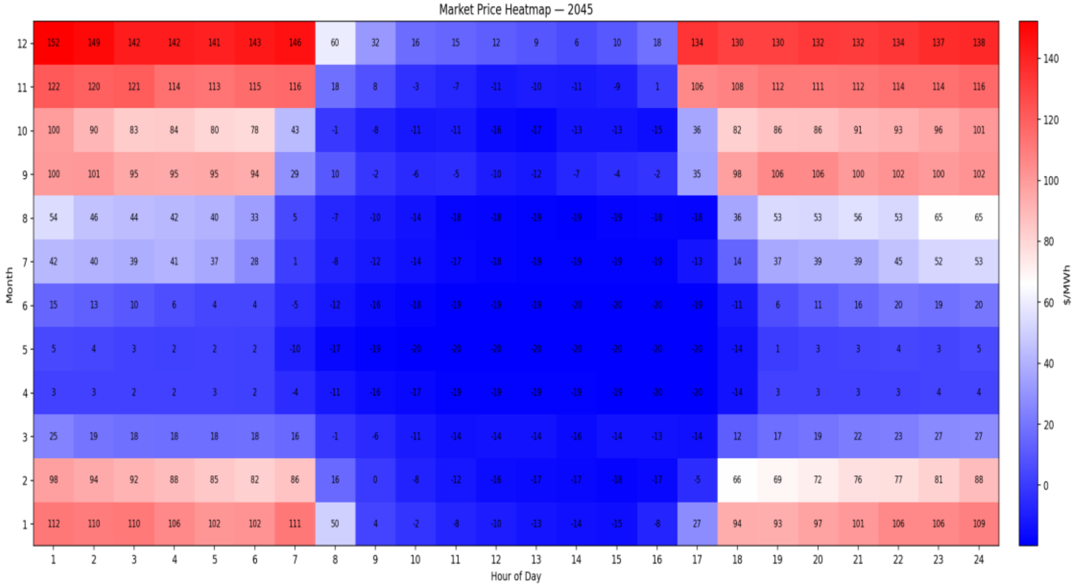




Forecast Price Heatmaps: 2040 and 2045

- Low-price midday pattern becomes deeper and more persistent.
- The low-price pattern extends across a larger portion of the year.
- Higher prices remain concentrated outside solar hours.





Reliability Metrics

Methodology and Results

Storage Dispatch – Energy Equity Logic

Storage is initially modeled through economic dispatch. On days with EUE, a post-processing adjustment is applied to better identify the hours in which incremental energy could have reduced the reliability shortfall.

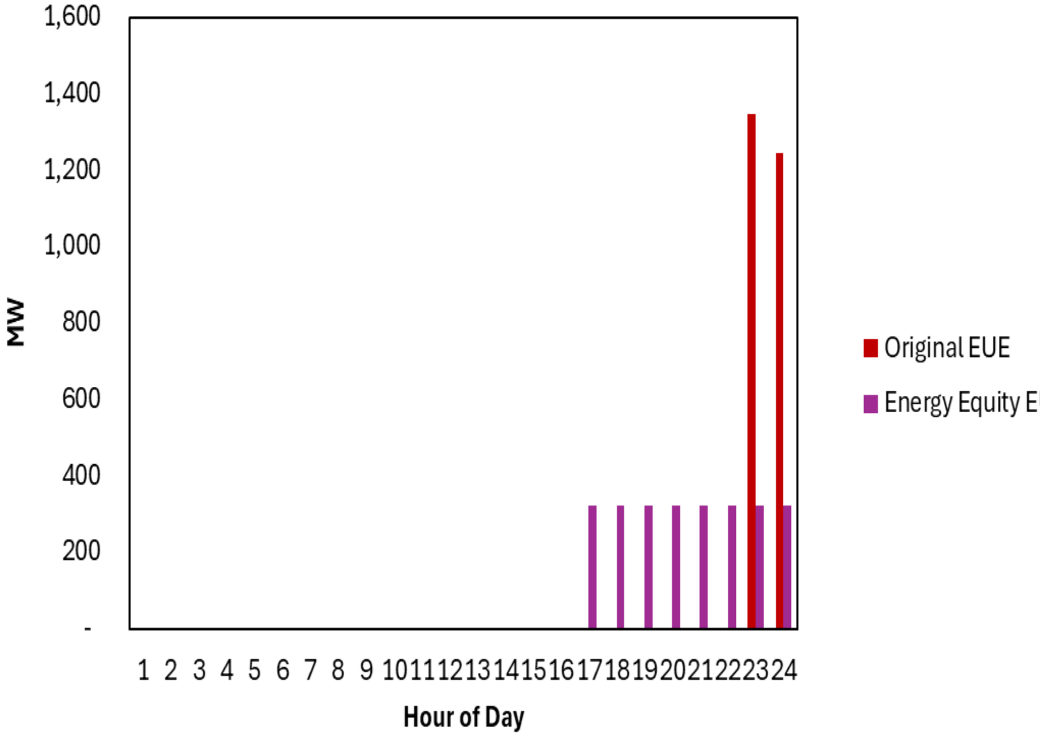
Post-processing approach recognizes that incremental energy available during discharge period could have helped reduce EUE:

- Identify storage resources that were depleted during the EUE event.
- Determine when those storage resources began discharging.
- Spread the original EUE across the identified storage-discharge period.
- Assigning reliability need to all hours in discharging period rather than assigning the reliability need only to the hours in which the final shortfall occurred.

Example:

- Original EUE occurs primarily in Hours 23–24.
- Energy-equity EUE is spread across Hours 17–24, when storage was being dispatched.
- **Total EUE is unchanged; only its hourly allocation changes.**

Unserved Energy in evening hours – Conventional versus Energy Equity dispatch. Total EUE in both cases is the same



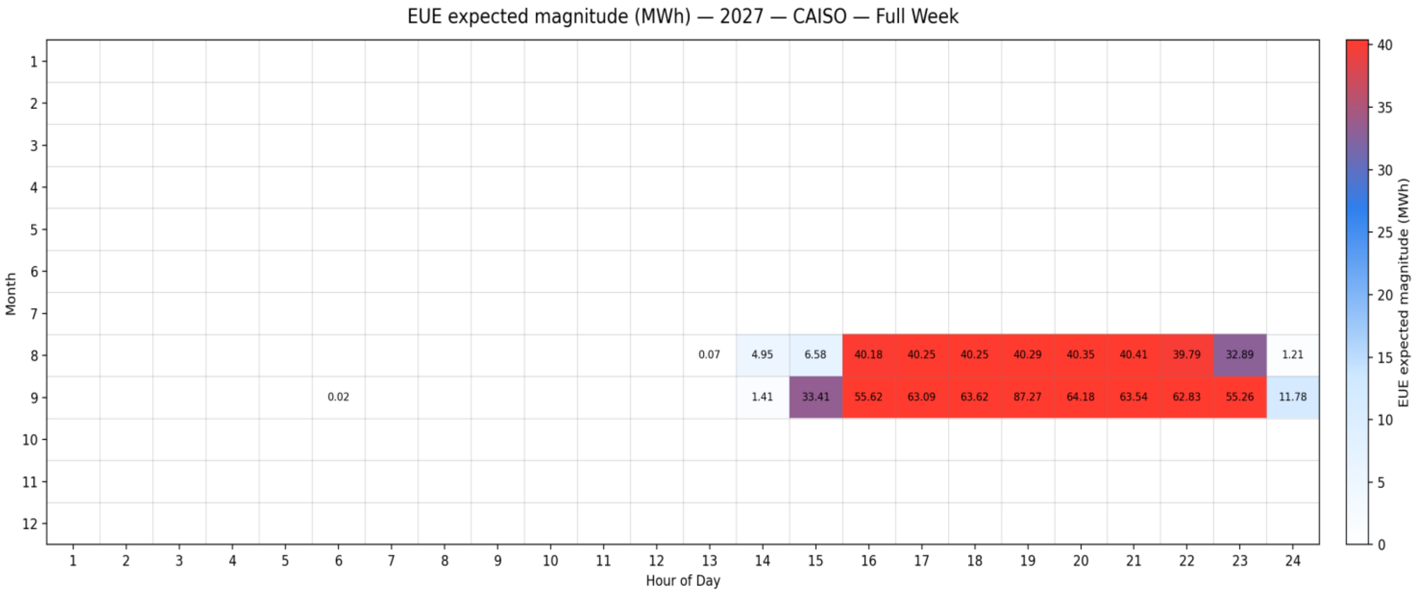
Reliability Metrics

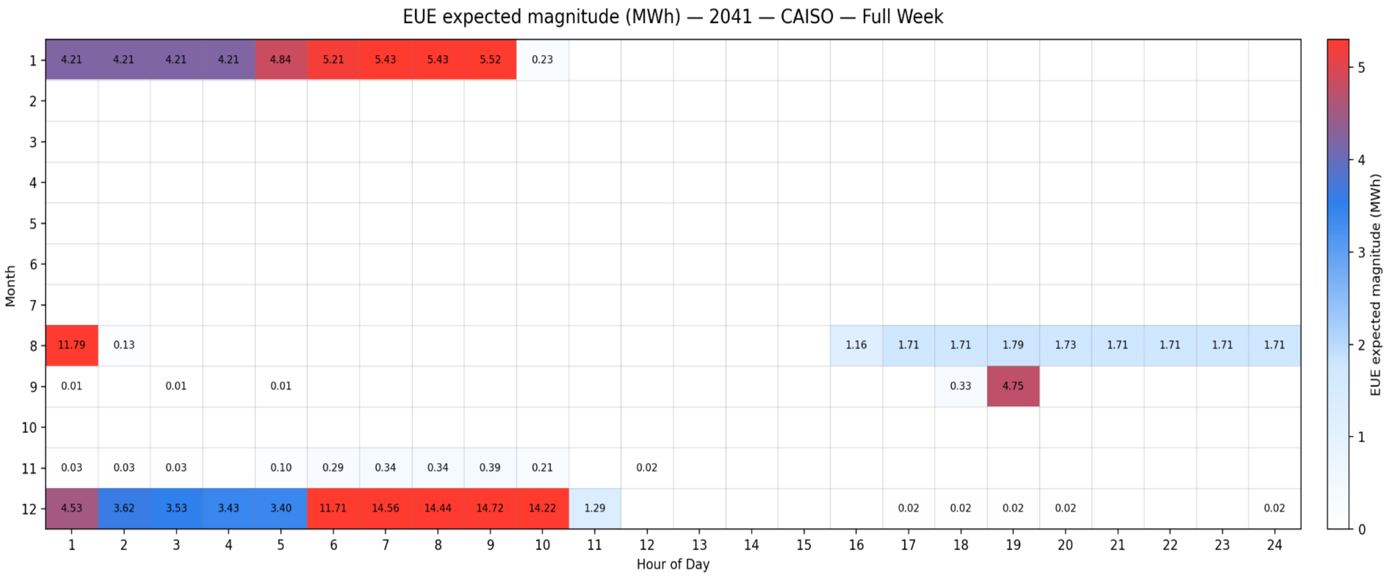
Loss of Load Magnitude and Expected Unserved Energy

Loss of Load Frequency

Distribution of EUE - 2027 and 2041

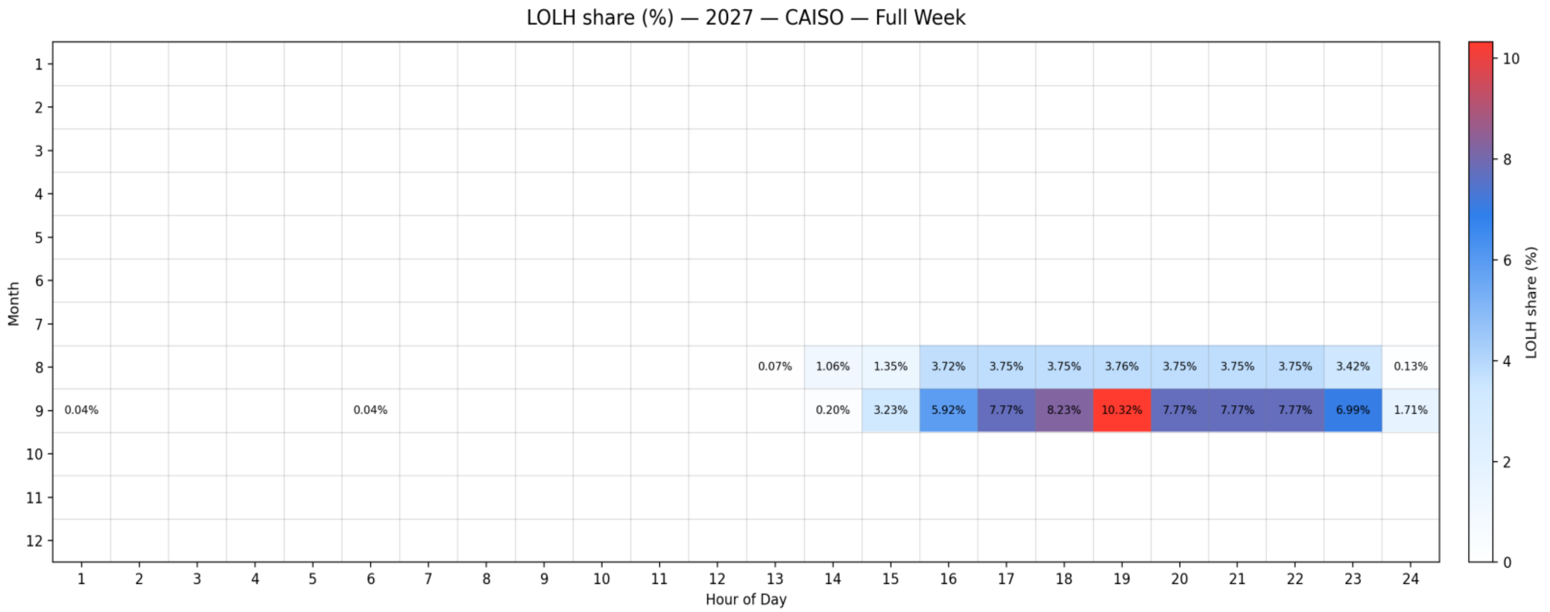
- Expected Unserved Energy (EUE) expected to occur in evenings in 2027 and move to mornings in winter by 2041.
- Energy Equity approach defines critical hours as all hours when stored energy is used to avoid shortages. Therefore critical hours reflect not just a single shortage hour, but entire critical period.

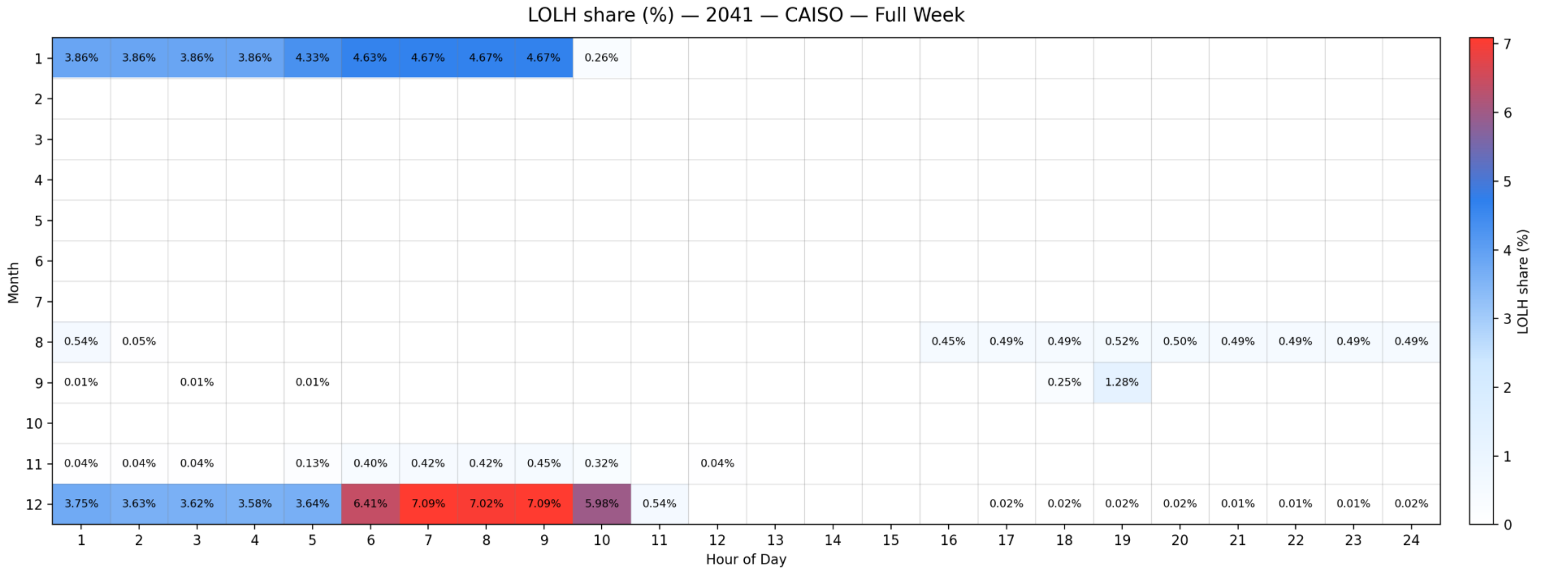




Reliability results use all modeled weather years; they are not based on the TMY price-forecast year.

Expected LOLH Distribution: 2027 and 2041





- LOLH shows the expected distribution of loss-of-load hours across all modeled weather years.
- 2027 loss-of-load risk is concentrated in late-summer afternoon and evening hours.
- By 2041, the distribution shifts toward winter morning hours, with additional risk in selected summer periods.
- The equity-based storage dispatch approach spreads reliability risk across several constrained peak hours rather than concentrating it within only a few evening peak hours.

Reliability results use all modeled weather years; they are not based on the TMY price-forecast year.

Conclusions

Conclusions

Backcasting

- Backasting 2022 in our 2026 TPP dataset and comparing to previous backcasting of 2022 provided a sound basis to validate and calibrate SERVM against observed CAISO dispatch and price behavior. Our work illustrates improved alignment with CAISO relative to the prior calibration cycle, including hourly price patterns, monthly error, and the observed price–gas relationship.
- We have improved but not perfected our replication of the current CAISO market, and it is not clear how the market will change in the future given increasing penetrations of solar and storage, integration of regional markets, and improved market operations practices and software.

Energy Prices

- Applying the calibrated framework to future TPP portfolios produces a consistent trend: greater solar and storage penetration lowers midday prices and shifts higher prices toward morning and evening hours. As we move further into the future, energy prices flatten throughout the day in the spring, and annual peak energy prices occur in winter months, peaking in evening hours of January and December by 2045.
- **Reliability Metrics**
- Growing electrification and fuel-switching demand increase system needs over time, while the timing of reliability risk shifts across the forecast horizon, from late-summer afternoon and evening hours in southern California currently toward additional winter morning risk in northern California by 2041. This is due to growing EV demand and electrification, as well as increased solar and storage investment in southern California.

Key Takeaway

- Overall backcasting and calibration to CAISO dispatch and price patters provide a more credible foundation to forecast future energy price, dispatch, and reliability needs. While our modeling is still improving, this is a credible framework to create avoided energy and reliability costs for the ACC.

Integrated Calculation

Generation Capacity and GHG Avoided Costs

Energy+Environmental Economics

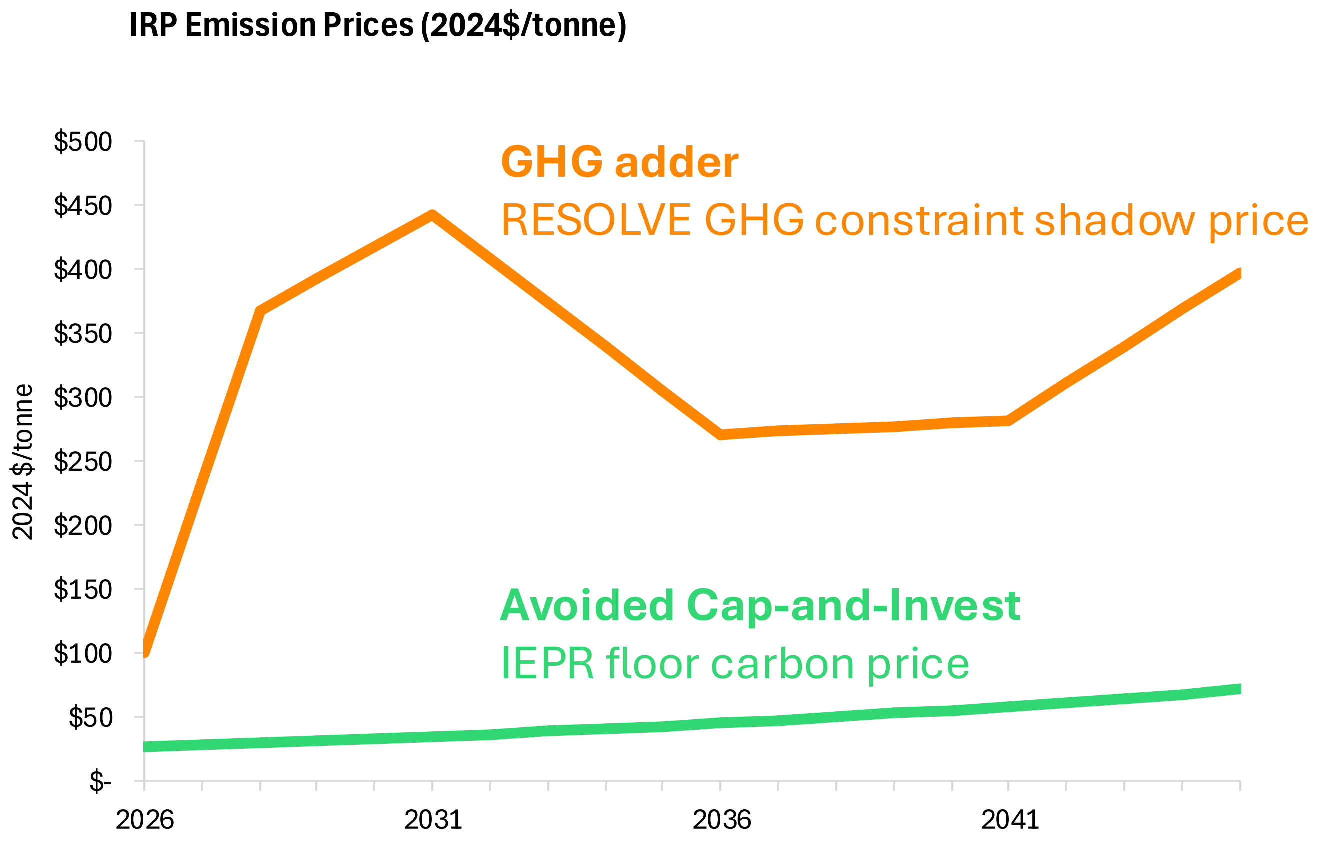
The methodology of generation capacity and GHG avoided costs has been updated for 2026 ACC

Core Equation: Resource Costs = Energy Value + Capacity Value + Greenhouse Gas Value

2024 ACC	2026 ACC	
Joint Optimization Used an optimization to solve for capacity and GHG avoided costs Solar and storage were represented as standalone resources	***GHG Avoided Costs (GHG Adder)*** Use IRP RESOLVE GHG “Shadow Prices”, representing the marginal cost per metric ton to achieve the required GHG target	***Generation Capacity Avoided Costs*** Calculated using hybrid solar and storage resources Based on the Real Economic Carrying Charge

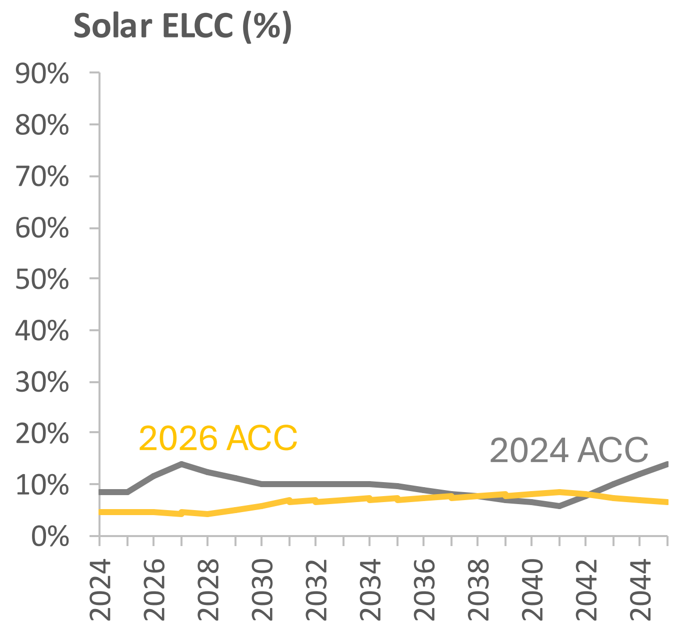
Emission related prices from IRP RESOLVE are used as GHG avoided costs

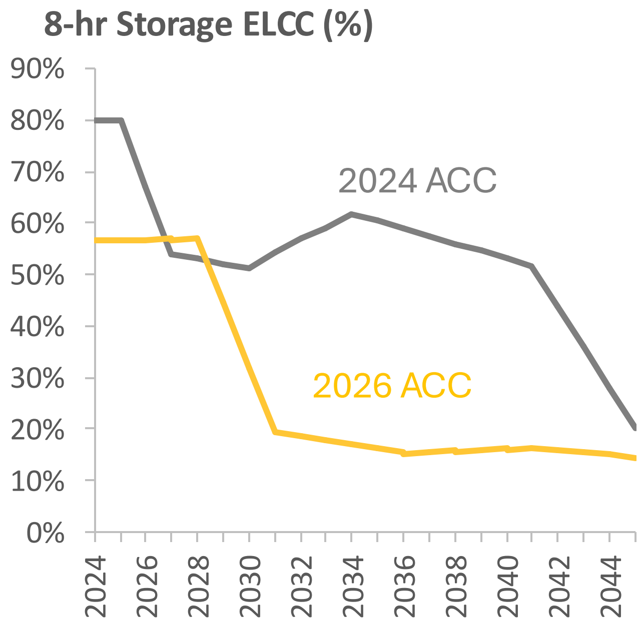
- **RESOLVE reports GHG shadow prices as costs incremental to the cap-and-invest program costs required to meet the GHG target. This is used as GHG adder.**
- **The floor cap-and-invest prices in the IRP are used as avoided Cap-and-Invest costs.**
- **Both prices are reported in 2024 \$ and converted to nominal \$ at 2% inflation for a given year n**
  - Nominal \$ (n) = 2024 \$ (n) x $(1 + 2\%)^{n-2024}$

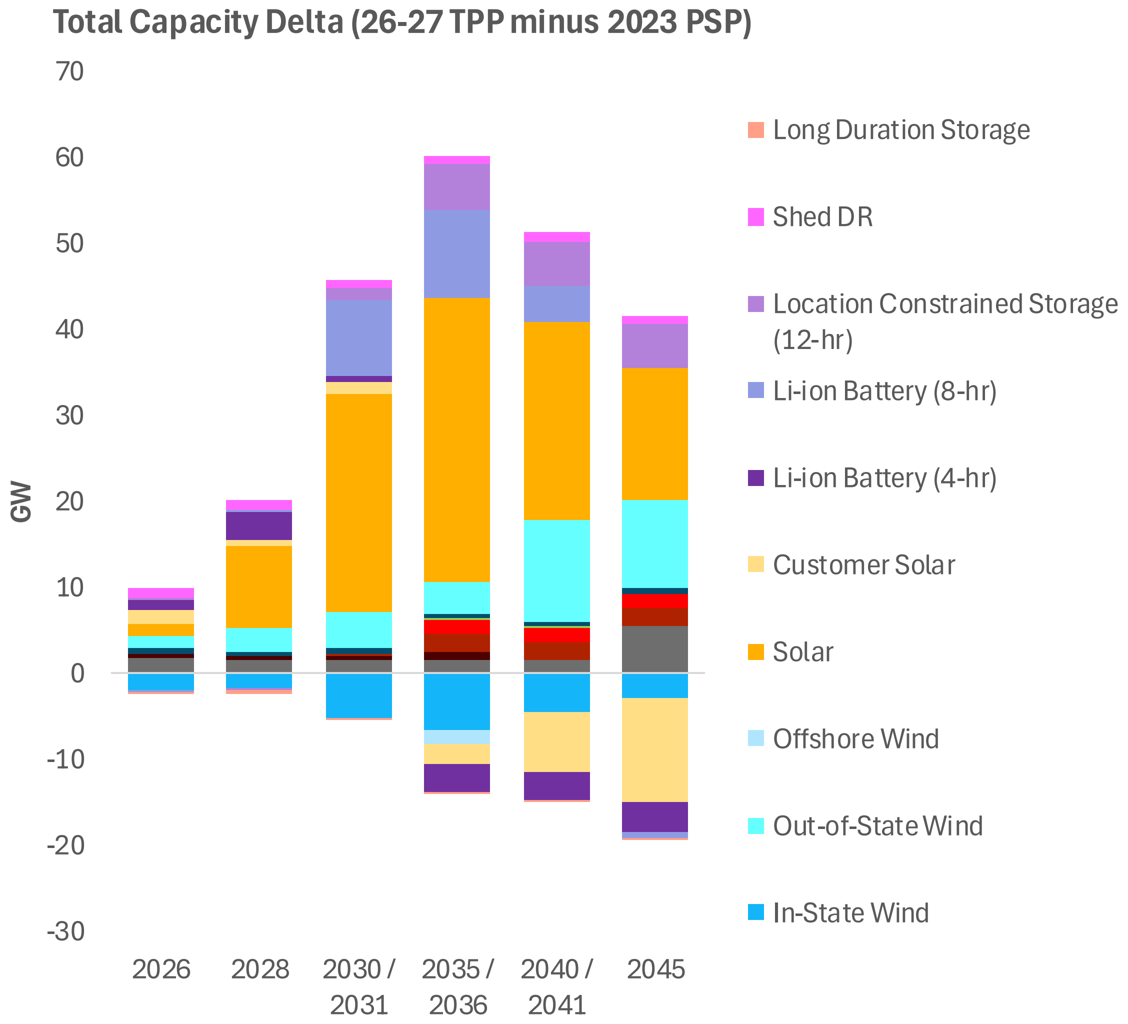


Storage ELCCs have decreased since 2024 ACC

- The 26-27 TPP portfolio underlying the 2026 ACC builds more solar and storage than the 2023 PSP, driven by increased load
- Saturation of the solar and storage reduces marginal ELCC





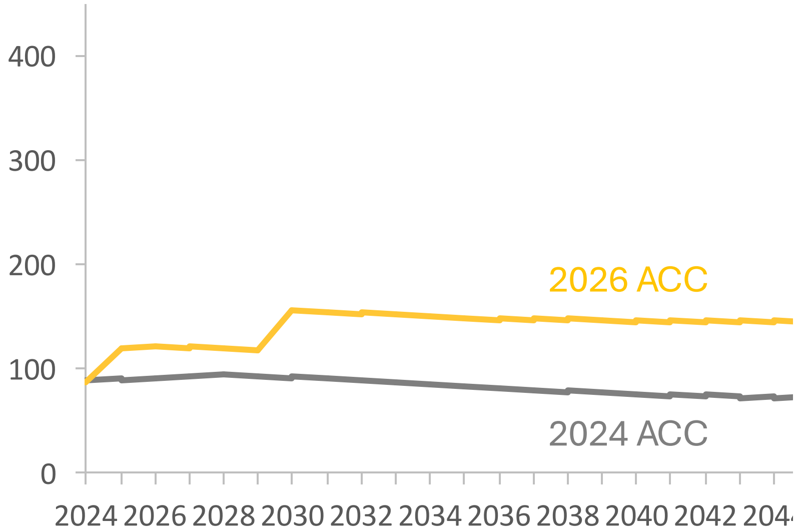


Resource costs have increased since 2024 ACC

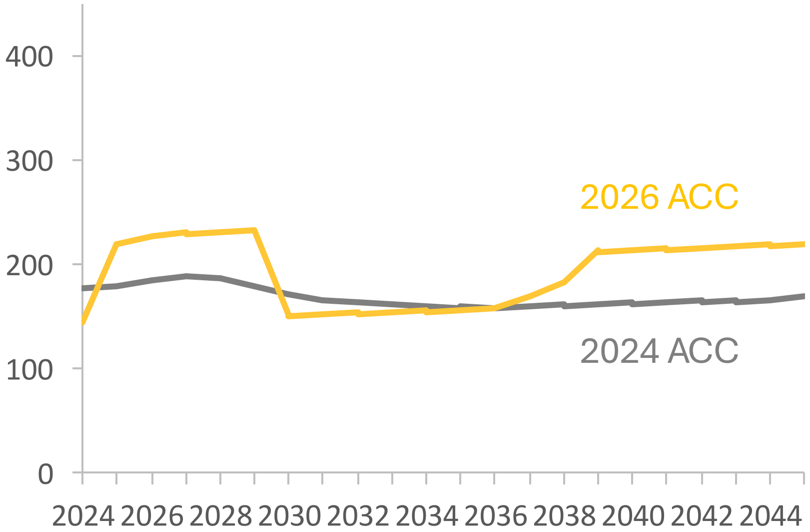
- Import tariffs on PV modules and lithium-ion battery cells raise installed capital costs through the late 2020s
- Absent policy effects, storage equipment costs continue to fall, which drives the step-down in storage costs at the start of the 2030s
- Utility-scale solar costs step up after 2030 with expiration of the production tax credit. Li-ion battery costs step up in the later 2030s with expiration of the investment tax credit.

Resource Levelized Fixed Costs

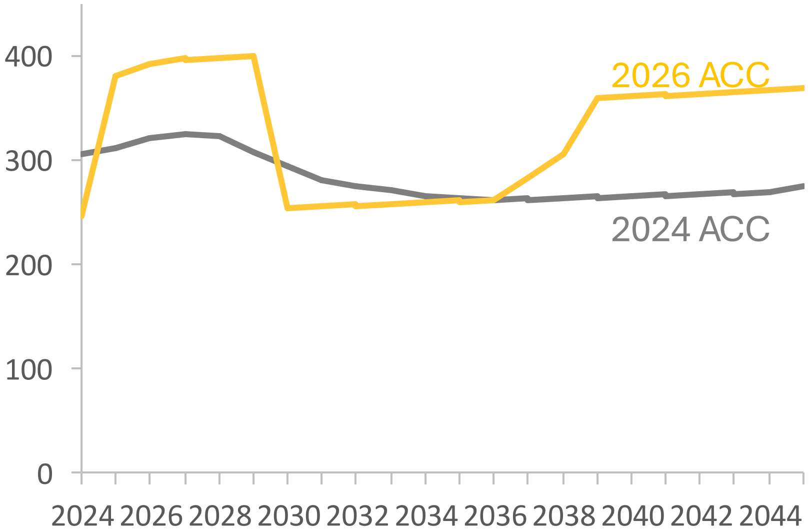
Solar (Nom$/kW-yr)



4-hr Storage (Nom$/kW-yr)



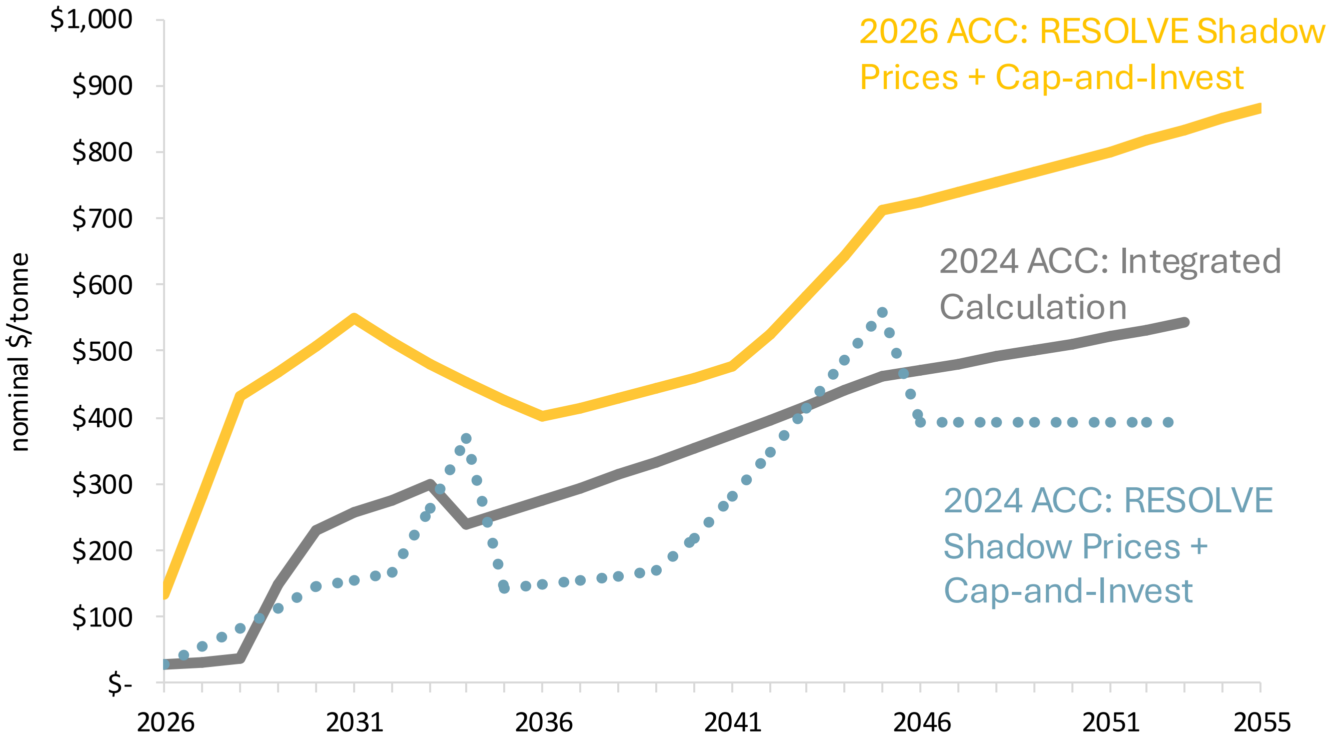
8-hr Storage (nom$/kW-yr)



GHG avoided costs have increased significantly compared to 2024 ACC

- While the methodology has changed from 2024 ACC to 2026 ACC, the high GHG avoided costs are primarily driven by resource cost increase
- GHG adder and avoided Cap-and-Invest Prices are used to calculate GHG contribution of hybrid solar + storage resources

GHG Avoided Costs, Including Cap-and-Invest (Nominal$/tonne)



Generation capacity avoided costs are calculated based on hybrid solar and storage resources

Gross RECC

Gross Real Economic Carrying Charge (RECC) represents the cost of deferring investment by one year, calculated based on solar and storage levelized fixed costs

minus

Energy Revenue

Energy revenues are based on hourly energy avoided costs, resource generation profile (solar) and Top-Bottom-X (storage)

minus

GHG Contribution

Resource GHG contribution is based on GHG avoided costs and hourly emission rates

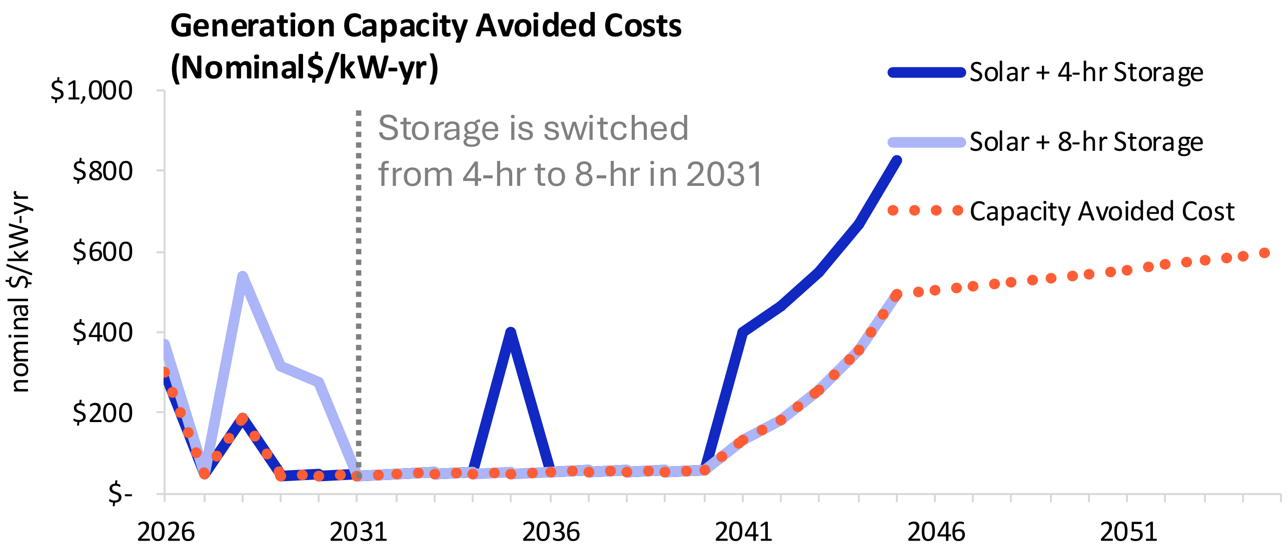
scaled by ELCC

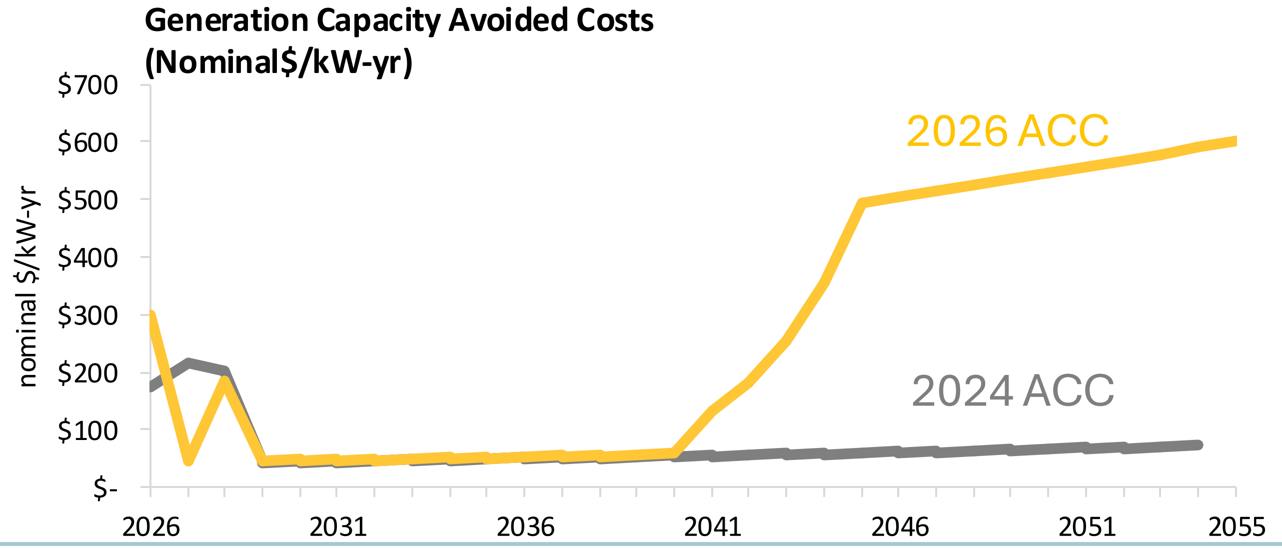
Generation Capacity Avoided Cost

Generation capacity avoided costs are calculated using solar + 4hr storage and solar + 8hr storage

Capacity avoided costs are high in the near-term and long-term

- **Capacity avoided costs are set by solar + 4-hr storage before 2031 and solar + 8-hr storage after 2031**
- **Capacity avoided costs involve over time:**
  - Near-term (2026–2028): Elevated storage capital costs are not offset by energy and GHG value, leaving a large residual capacity value. Year-to-year variation reflects the timing of tariff.
  - Mid-term (2029–2040): Energy and GHG value alone recover the resource fixed costs, so the capacity value is set to be existing gas O&M costs.
  - Long-term (2041–2055): Elevated costs, declining energy value and ELCC under high solar and storage penetration results in high capacity value.





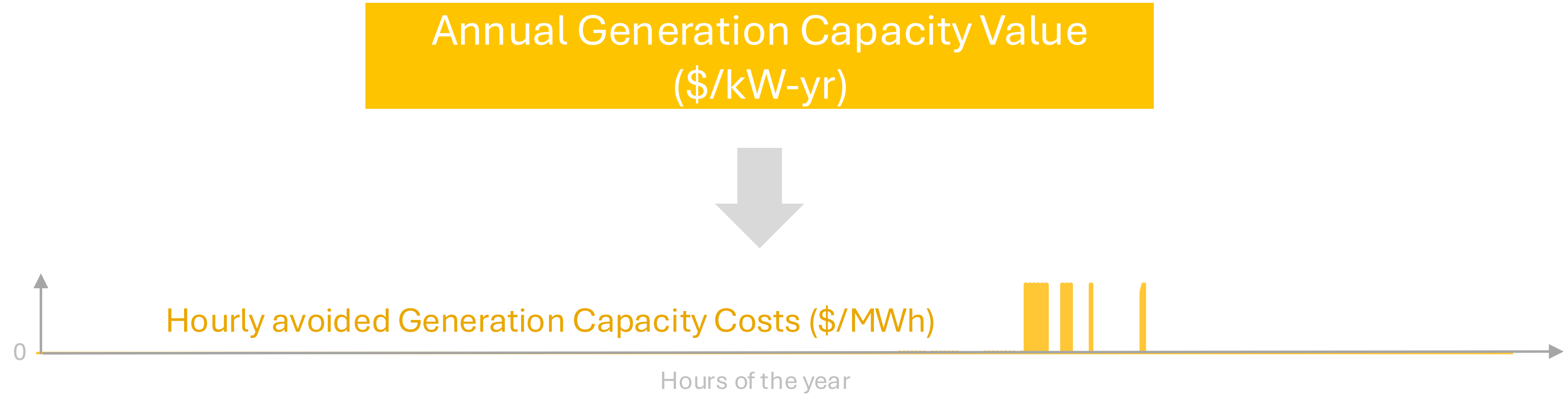
Generation Capacity Allocation

Loss-of-Load Hours approach

Energy+Environmental Economics

Refinement of hourly allocation of generation capacity value

- Use of Loss of Load Hours (LOLH) rather than Expected Unserved Energy (EUE) for calculating generation capacity allocation factors
- Use of energy prices rather than temperature to allocate generation capacity value to specific days of the year
- Allocate all capacity values to weekdays given reliability modeling results



Capacity allocation factors in near-term

- **Allocation based on LOLH gives more weight to hours in which loss of load occurs *more frequently*, regardless of the magnitude of unserved energy.**
  - Hours with more frequent loss-of-load events are more likely to benefit from DER dispatch in reducing loss-of-load risk.
- **In the near-term, LOLH concentrated in summer evenings, which is similar to the 2024 ACC**

2026 % EUE by Month-Hour (2024 ACC)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	0.01%	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	0.02%	-	-	-	-
16	-	-	-	-	-	-	-	0.17%	0.14%	-	-	-
17	-	-	-	-	-	-	-	12.42%	0.86%	-	-	-
18	-	-	-	-	-	-	0.02%	12.69%	5.88%	-	-	-
19	-	-	-	-	-	-	0.27%	13.14%	8.19%	-	-	-
20	-	-	-	-	-	-	0.15%	14.34%	3.52%	-	-	-
21	-	-	-	-	-	-	-	13.04%	1.04%	-	-	-
22	-	-	-	-	-	-	-	12.96%	1.04%	-	-	-
23	-	-	-	-	-	-	-	0.04%	0.05%	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-

2027 % LOLH by Month-Hour (2026 ACC)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1	-	-	-	-	-	-	-	-	0.04%	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	0.04%	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	0.07%	-	-	-	-
14	-	-	-	-	-	-	-	1.06%	0.20%	-	-	-
15	-	-	-	-	-	-	-	1.35%	3.23%	-	-	-
16	-	-	-	-	-	-	-	3.72%	5.92%	-	-	-
17	-	-	-	-	-	-	-	3.75%	7.77%	-	-	-
18	-	-	-	-	-	-	-	3.75%	8.23%	-	-	-
19	-	-	-	-	-	-	-	3.76%	10.32%	-	-	-
20	-	-	-	-	-	-	-	3.75%	7.77%	-	-	-
21	-	-	-	-	-	-	-	3.75%	7.77%	-	-	-
22	-	-	-	-	-	-	-	3.75%	7.77%	-	-	-
23	-	-	-	-	-	-	-	3.42%	6.99%	-	-	-
24	-	-	-	-	-	-	-	0.13%	1.71%	-	-	-

Capacity allocation factors in mid-term

+ In the mid-term, LOLH concentrated in summer evenings, similar to the 2024 ACC

- However, in the 2026 ACC, LOLH starts to spread to early morning hours in summer months, and winter mornings also have a small risk of loss-of-load

2030 % EUE by Month-Hour (2024 ACC)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	0.10%	0.03%	-	-	-
16	-	-	-	-	-	-	-	0.67%	0.28%	-	-	-
17	-	-	-	-	-	-	0.01%	5.64%	2.15%	-	-	-
18	-	-	-	-	-	-	0.09%	10.72%	8.95%	-	-	-
19	-	-	-	-	-	-	0.53%	11.00%	8.31%	-	-	-
20	-	-	-	-	-	-	0.34%	11.51%	4.11%	-	-	-
21	-	-	-	-	-	-	0.09%	11.45%	3.46%	-	-	-
22	-	-	-	-	-	-	0.09%	11.45%	3.39%	-	-	-
23	-	-	-	-	-	-	0.09%	1.21%	2.04%	-	-	-
24	-	-	-	-	-	-	0.08%	1.07%	1.12%	-	-	-

2031 % LOLH by Month-Hour (2026 ACC)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1	-	-	-	-	-	-	-	2.03%	1.90%	-	0.67%	-
2	-	-	-	-	-	-	-	0.01%	0.25%	-	0.67%	-
3	-	-	-	-	-	-	-	-	-	-	0.62%	-
4	-	-	-	-	-	-	-	-	-	-	0.67%	-
5	0.03%	-	-	-	-	-	-	-	-	-	0.72%	-
6	0.06%	-	-	-	-	-	-	-	0.24%	-	0.68%	-
7	0.13%	-	-	-	-	-	-	-	-	-	0.70%	-
8	0.13%	-	-	-	-	-	-	-	-	-	0.78%	-
9	0.13%	-	-	-	-	-	-	-	-	-	0.78%	-
10	0.04%	-	-	-	-	-	-	-	-	-	0.52%	-
11	-	-	-	-	-	-	-	-	-	-	0.01%	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	0.03%	-	-	-	-
14	-	-	-	-	-	-	-	0.17%	1.18%	-	-	-
15	-	-	-	-	-	-	-	0.48%	1.73%	-	-	-
16	-	-	-	-	-	-	-	4.94%	2.29%	-	-	-
17	-	-	-	-	-	-	-	5.02%	3.21%	-	-	-
18	-	-	-	-	-	-	-	4.94%	4.45%	-	-	-
19	-	-	-	-	-	-	-	5.28%	12.62%	-	-	-
20	-	-	-	-	-	-	-	5.36%	3.92%	-	-	-
21	-	-	-	-	-	-	-	4.94%	3.21%	-	-	-
22	-	-	-	-	-	-	-	4.94%	3.21%	-	-	-
23	-	-	-	-	-	-	-	4.94%	3.21%	-	-	-
24	-	-	-	-	-	-	-	4.94%	3.21%	-	-	-

Capacity allocation factors in long-term

+ **In the long-term, LOLH is spread nearly evenly across both morning and evening hours and there is a shift of risk from summer to winter in the 2026 ACC**
  - Driven by increased penetration of batteries and challenges with serving electrification load growth under transmission constraints (SCE → PG&E energy flow is at the transfer limit across many hours with LOLH)

2040 % EUE by Month-Hour (2024 ACC)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1	-	-	-	-	-	-	0.42%	0.22%	3.22%	-	-	-
2	-	-	-	-	-	-	0.00%	-	0.01%	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	0.01%	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	0.04%	0.01%	-	-	-
14	-	-	-	-	-	-	0.02%	0.29%	0.03%	-	-	-
15	-	-	-	-	-	-	0.04%	0.48%	0.10%	-	-	-
16	-	-	-	-	-	-	0.28%	1.20%	0.74%	-	-	-
17	-	-	-	-	-	-	0.55%	3.29%	2.97%	-	-	-
18	-	-	-	-	-	-	1.11%	5.66%	4.83%	-	-	-
19	-	-	-	-	-	-	1.57%	6.10%	5.32%	-	-	-
20	-	-	-	-	-	-	1.74%	6.66%	5.90%	-	-	-
21	-	-	-	-	-	-	1.68%	6.40%	5.93%	-	-	-
22	-	-	-	-	-	-	1.63%	5.24%	4.92%	-	-	-
23	-	-	-	-	-	-	1.72%	4.85%	4.53%	-	-	-
24	-	-	-	-	-	-	1.64%	4.30%	4.35%	-	-	-

2041 % LOLH by Month-Hour (2026 ACC)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1	2.46%	-	-	-	-	-	-	0.34%	0.01%	-	0.02%	2.39%
2	2.46%	-	-	-	-	-	-	0.03%	-	-	0.02%	2.31%
3	2.46%	-	-	-	-	-	-	-	0.01%	-	0.02%	2.31%
4	2.46%	-	-	-	-	-	-	-	-	-	-	2.28%
5	2.76%	-	-	-	-	-	-	-	0.01%	-	0.08%	2.32%
6	2.95%	-	-	-	-	-	-	-	-	-	0.26%	4.09%
7	2.97%	-	-	-	-	-	-	-	-	-	0.27%	4.52%
8	2.97%	-	-	-	-	-	-	-	-	-	0.27%	4.47%
9	2.97%	-	-	-	-	-	-	-	-	-	0.29%	4.52%
10	0.17%	-	-	-	-	-	-	-	-	-	0.20%	3.80%
11	-	-	-	-	-	-	-	-	-	-	-	0.32%
12	-	-	-	-	-	-	-	-	-	-	0.02%	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	0.29%	-	-	-	-
17	-	-	-	-	-	-	-	0.32%	-	-	-	2.39%
18	2.46%	-	-	-	-	-	-	0.32%	0.16%	-	-	2.39%
19	2.46%	-	-	-	-	-	-	0.33%	0.81%	-	-	2.39%
20	2.46%	-	-	-	-	-	-	0.32%	-	-	-	2.39%
21	2.46%	-	-	-	-	-	-	0.32%	-	-	-	2.39%
22	2.46%	-	-	-	-	-	-	0.32%	-	-	-	2.39%
23	2.46%	-	-	-	-	-	-	0.32%	-	-	-	2.39%
24	2.46%	-	-	-	-	-	-	0.32%	-	-	-	2.39%

Raw SERVM LOLH heatmaps were further post-processed. For more information, see documentation Section 4.

Transmission and Distribution Capacity Values

Energy+Environmental Economics

Transmission Avoided Costs

- Calculation of transmission avoided costs utilizes the same overall approach applied in past ACC cycles while aligning specific methodology applied across utilities
- Transmission value inputs come from utility General Rate Case filings and supplemental data request responses

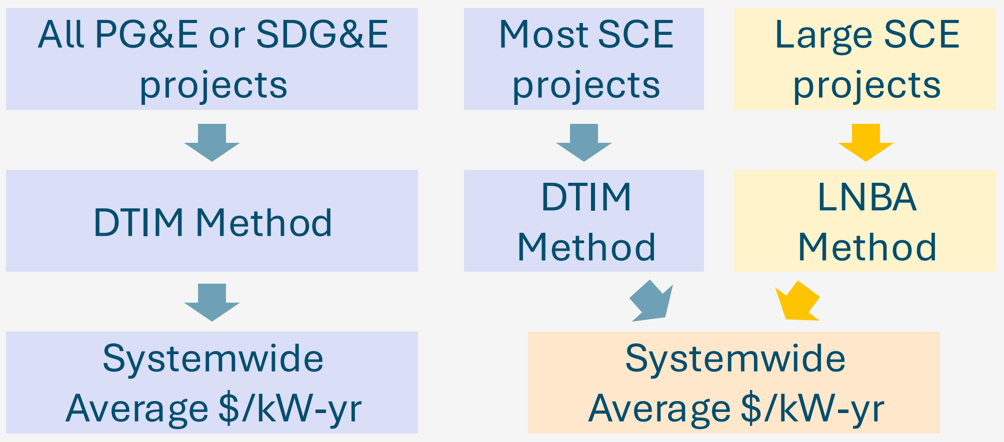
Component	Data Sources	Calculations
Marginal Transmission Cost ($/kW-yr)	Utility GRC filings and data requests responses	**PG&E**: Value set by prior CPUC ruling **SCE** & **SDGE**: Discounted Total Investment Method
Hourly Allocation of Transmission Value ($/kWh)	**2026 Loads**: CAISO Energy Management dataset **Future Year Loads**: SERVM modeling	Peak Capacity Allocation Factor (PCAF) method with values realigned to match temperatures in the ACC typical meteorological year

See 2024 ACC Documentation, Appendix 12.3-12.5 for calculation detail

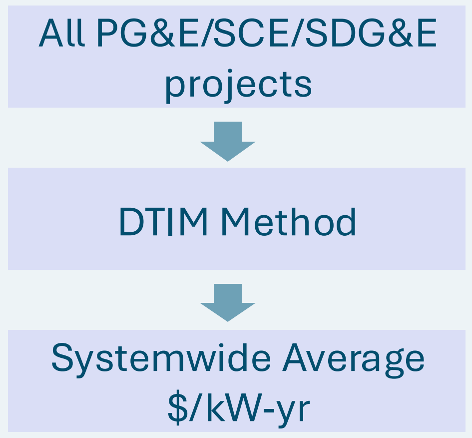
The 2026 transmission avoided cost calculation applies consistent deferral calculation methodology across utilities

- **Prior cycles applied the Discounted Total Investment Method (DTIM) and Locational Net Benefits Analysis (LNBA) approach depending on utility data provided**
  - **PG&E** & **SDG&E**: DTIM for all capacity-related transmission projects (Recent PG&E values had been set by a CPUC ruling)
  - **SCE**: DTIM for general systemwide transmission projects; LNBA for individual large projects (1-2 included each year)
- **In the 2026 ACC cycle, the DTIM is applied for all utilities and projects, ensuring consistent treatment**
  - This improves stability of avoided cost values against uneven impacts from individual large projects
  - This also reduces volatility due to the ‘lumpiness’ of transmission expenditures compared to project useful life

Prior Methodology



Updated Methodology



Capacity-related expenditures drive changes in transmission avoided cost value

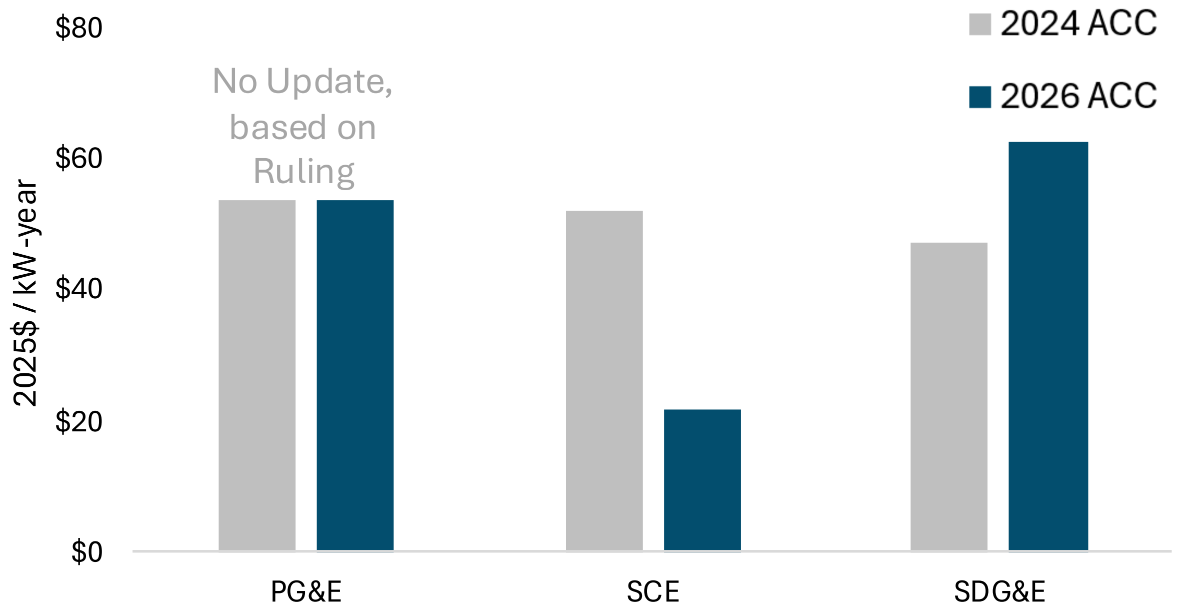
Transmission Avoided Costs (2025$/kW-yr)

Utility	2024ACC	2026ACC	% Change
PG&E	$53.98	**$53.98**	0%
SCE	$52.30	**$22.03**	- 58%
SDG&E	$47.23	**$62.74**	+ 33%

The large decrease in SCE value is primarily due to the 2024 inclusion of a large project which SCE has since noted should not be categorized as a capacity-related investment

SDG&E's transmission value increased based on expected near-term expenditures

Transmission Avoided Costs – 2026 ACC vs 2024 ACC (2025$ / kW-yr)



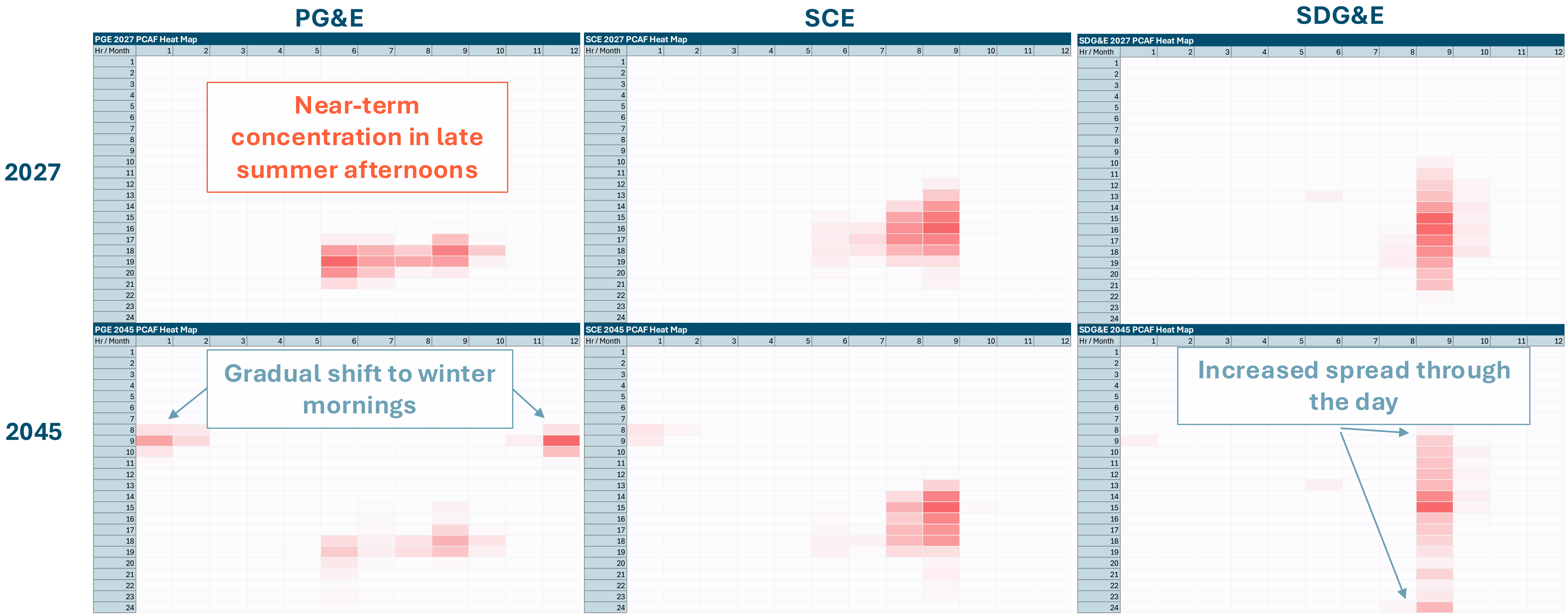
Transmission value is allocated following a Peak Capacity Allocation Factor approach

+ **Under the PCAF approach, transmission value is allocated across the highest load hours of the year***
  - Top load hours are defined as any that exceed Annual peak load – 1 Standard Deviation
  - To avoid extreme concentration of value where historical data focuses on an abnormally peaky year, between 100-250 hours are included.
+ **2026 Allocations use 2025 historical load data from the CAISO EMS dataset**
+ **NEW: To reflect changing timing of transmission constraints, future years use SERVM forecasted loads**
  - SERVM forecasted load is already aligned with Typical Metrological Year (TMY)
  - It also reflects future evolvement of load components (e.g., electrification, BTM generation)

**Load values for transmission are net of Behind-the-Meter generation*

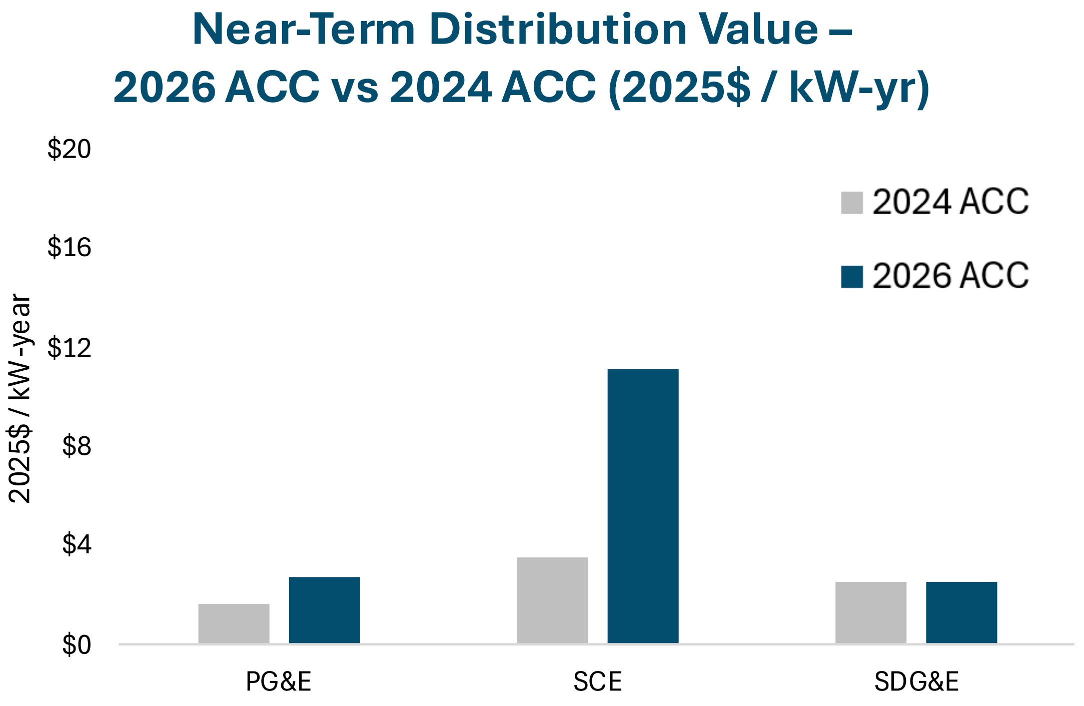
Future year allocation spreads value throughout the day and into winter months

+ Resulting transmission values follow a similar trend to generation capacity avoided costs



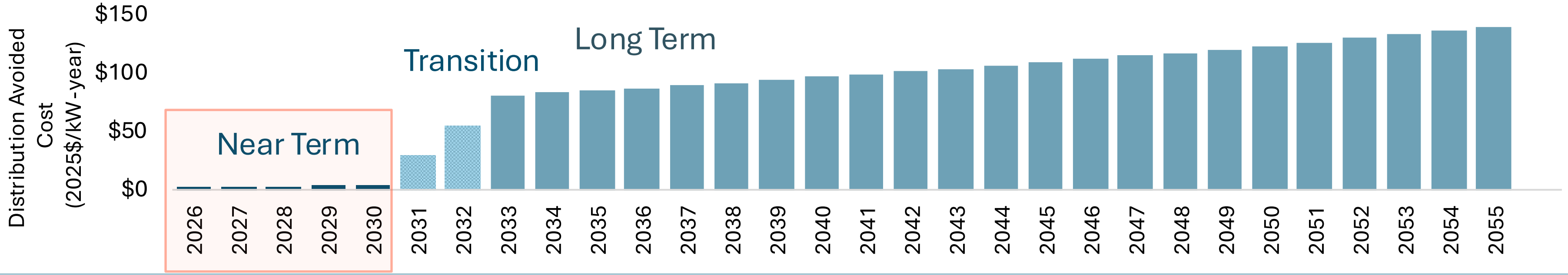
Transmission PCAFs are calculated from load net of BTM generation

Near-term distribution costs increase for SCE and PG&E



- **Increases in SCE values are driven by higher O&M costs and greater alignment between projected DER installs and localized constraints**
- **A bug fix to prevent double-counting of DER capacity across facility types increases $/kW of DER values across utilities**
  - For SDG&E this balances out decreases in value from updated inputs

	ACC Vintage	PG&E	SCE	SDG&E
Near-Term Marginal Distribution	2024 ACC Update	$1.62	$3.49	$2.49
	2026 ACC Update	**$2.76**	**$11.21**	**$2.53**



Conclusion and Follow-up

California Public Utilities Commission

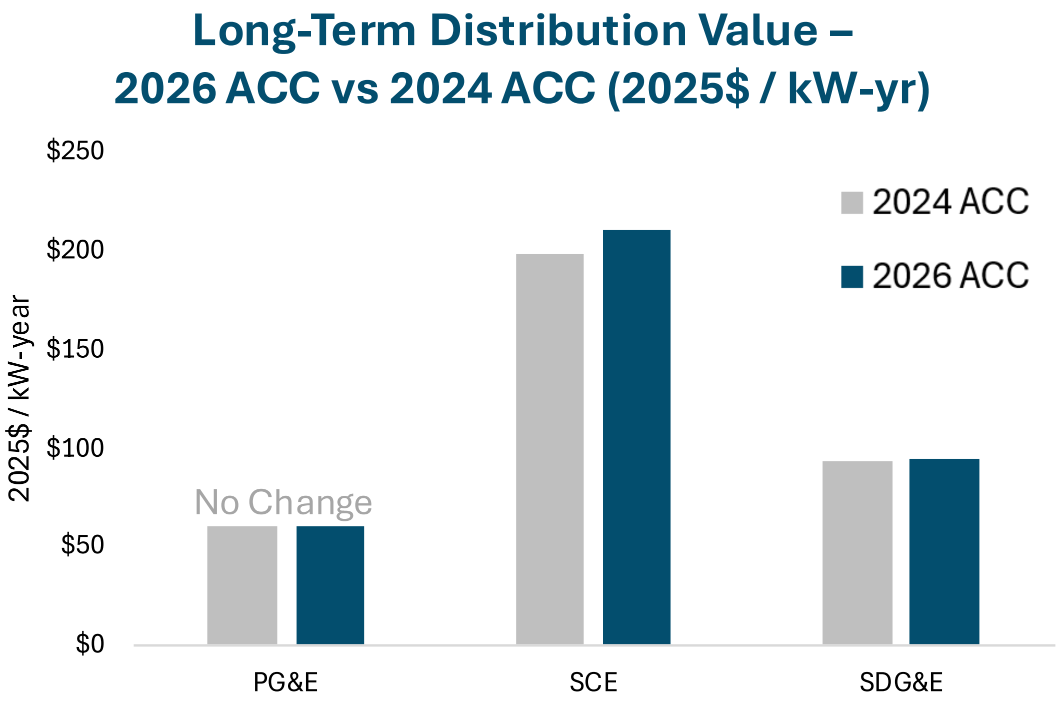
Appendix

Distribution Avoided Costs

+ **Calculation of distribution avoided costs maintains the approach applied in the 2024 ACC cycle, using updated inputs provided by the utilities in filings and data request responses**

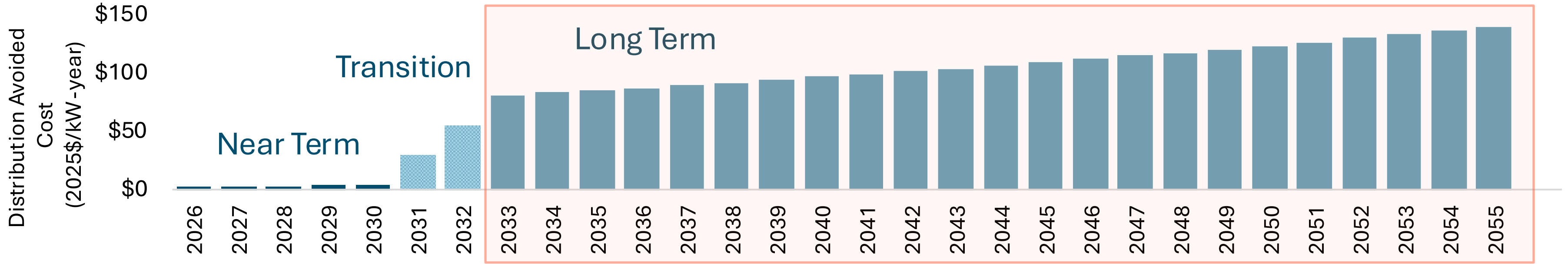
Component	Data Source	Calculations
Near Term Marginal Distribution Cost ($/kW-yr)	Utility Grid Needs Assessments (GNA) & Distribution Upgrade Project Reports (DUPR) (*formerly Distribution Deferral Opportunities Report*)	Use of 2019 T&D White Paper methodology to determine *incremental* overloads and resulting upgrade costs in a counterfactual future without forecasted DERs
Long Term Marginal Distribution Cost ($/kW-yr)	Utility GRC Filings	Weighted grouping of GRC costs by climate zone (PG&E); Sum of cost components presented in GRC (SCE, SDG&E)
Hourly Allocation of Distribution Value ($/kWh)	**PG&E**: Utility GRC Phase II filings **SCE**: Utility-provided Peak Load Risk Factors (PLRFs) based on 2023 loads **SDG&E**: Utility-supplied 2025 load data	PCAF or equivalent method (calculated by utilities for PG&E, SCE) with values realigned to match temperatures in a typical weather year

Stable long-term distribution costs temper changes to overall levelized values



- **Long-term distribution values show little change in real dollar terms**
  - PG&E values remain constant since the 2022 ACC as no new marginal distribution cost filings have been approved
- **The greater weight of long-term values keeps levelized distribution avoided costs in line with the 2024 ACC**

	ACC Vintage	PG&E	SCE	SDG&E
Long-Term Marginal Distribution	2024 ACC Update	$60.19	$198.46	$93.88
	2026 ACC Update	**$60.19**	**$210.38**	**$94.47**



Distribution PCAF values vary by climate zone but remain similar to the 2024 ACC