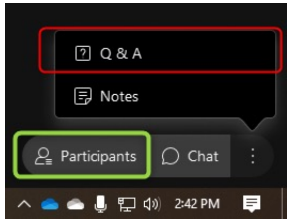
2024 CPUC Draft Avoided Cost Calculator Workshop

July 23, 2024

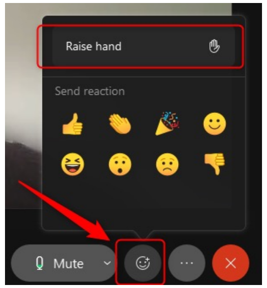
General Information

- **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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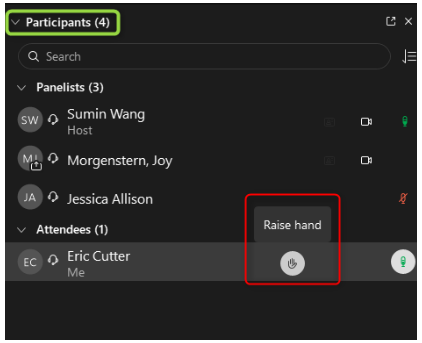
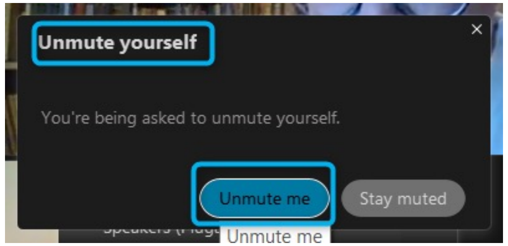


Unmute
A host will unmute you –
then you must click button to unmute yourself



Agenda and Schedule

Topic	Presenter	Duration
Opening by the Commissioner and Workshop Agenda	CPUC	1:00 — 1:05pm
Comparison of 2024 and 2022 ACC (TRC) + discussion	E3	1:05 — 1:30pm
Overview of SERVM data + discussion	Astrape/CPUC	1:30 — 2:15pm
Integrated Calculation of Generation Capacity and GHG Avoided Costs + discussion	E3	2:15— 2:40pm
Break		2:40 — 2:50pm
Allocation of Generation Capacity Value to EUE Hours + discussion	Astrape/CPUC	2:50 — 3:20pm
Transmission and Distribution Avoided Costs + discussion	E3	3:20 — 3:45pm
Societal Cost Test Methodology and Results + discussion	E3	3:45 — 4:00pm

Opening Remarks

Commissioner Houck

Comparison of 2024 and 2022

TRC Avoided Costs

Energy+Environmental Economics

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

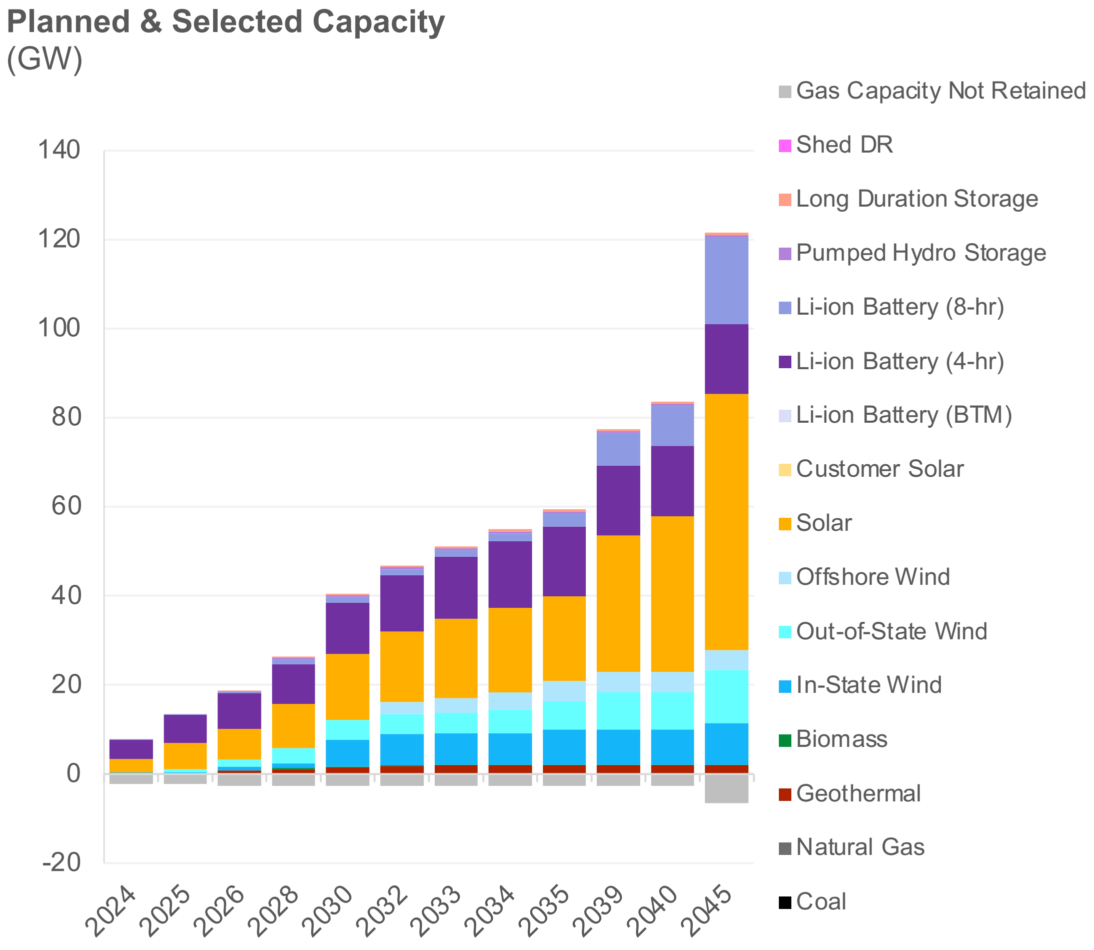
2024 ACC Update Overview

- **Key methodology changes for the 2024 ACC Electric Model were reviewed in detail in the 2024 ACC Staff Proposal and in the Proposed Decision Adopting Changes to the Avoided Cost Calculator mailed June 26, 2024 (R.22-11-013). These updates include:**
  - Change in baseline portfolio of resources from No New DER portfolio to the IRP's latest adopted system plan (this year, the **2023 Preferred System Plan (PSP)**
  - Calculation of Generation Capacity and GHG avoided cost using an **integrated calculation** instead of calculating values independently
  - **Updated storage dispatch algorithm** in SERVM for calculating hourly allocation factors for Generation Capacity to better capture the flexibility of energy storage. This provides a more comprehensive picture of critical periods when additional generation could improve reliability
  - Additional calibration and benchmarking of SERVM production cost modelling results
  - Moving the Refrigerant Avoided Cost Calculator to the DEER proceeding
- **Transmission and Distribution avoided costs were updated based on the latest utility filings and demand forecasts while maintaining the same transmission and 2019 T&D White Paper methodology**
- **The 2024 ACC now 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)**
  - The standard ACC is now referred to as the Total Resource Cost (TRC) version

2024 ACC is based on 2023 IRP's Preferred System Plan

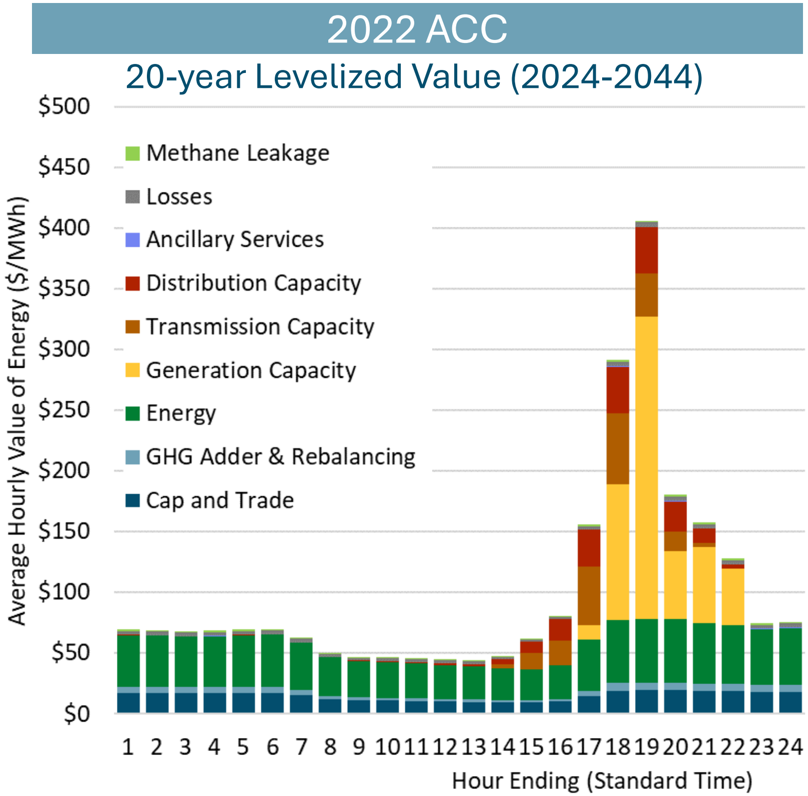
- **2024 ACC is based on the portfolio of IRP's latest adopted system plan (i.e., 2023 Preferred System Plan (PSP)) rather than No New DER portfolio**
- **2024 ACC is closely linked to IRP PSP. For example:**
  - The PSP portfolio produced by RESOLVE is simulated in SERVM to produce energy avoided costs
  - 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

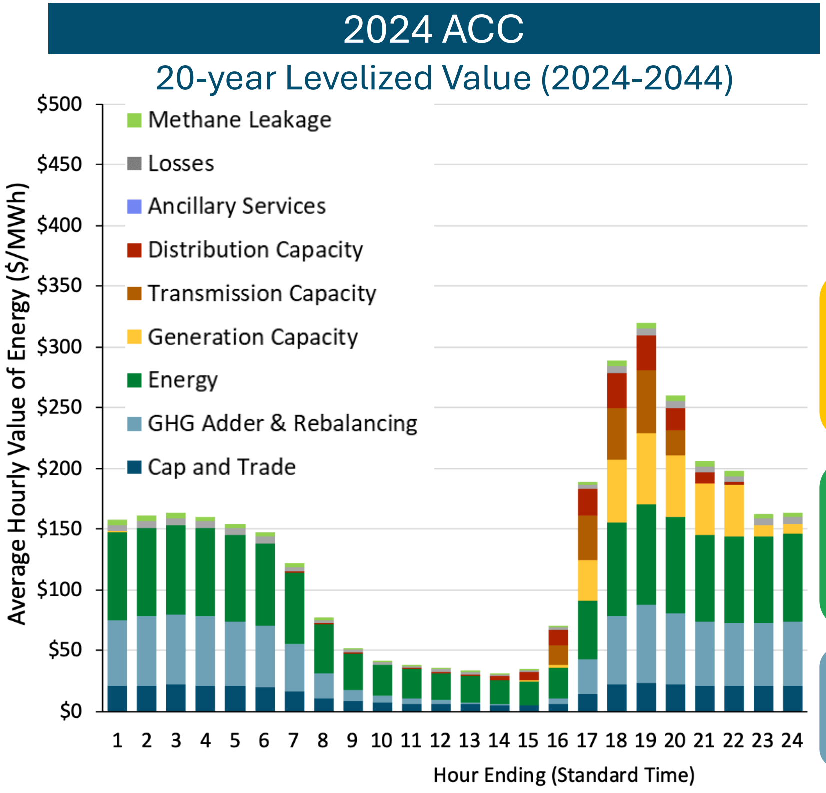
CPUC IRP PSP New Capacity



Energy, generation capacity and GHG avoided costs have changed the most between 2022 and 2024 ACC

- Energy value is more time-dependent (lower in midday and higher overnight and early morning)
- Higher GHG value that concentrates in evenings and early mornings
- Lower annual Generation Capacity value which is also spread-out over more hours
- Slightly lower Distribution value due to significantly lower near-term value but unchanged long-term value





Lower Capacity Value

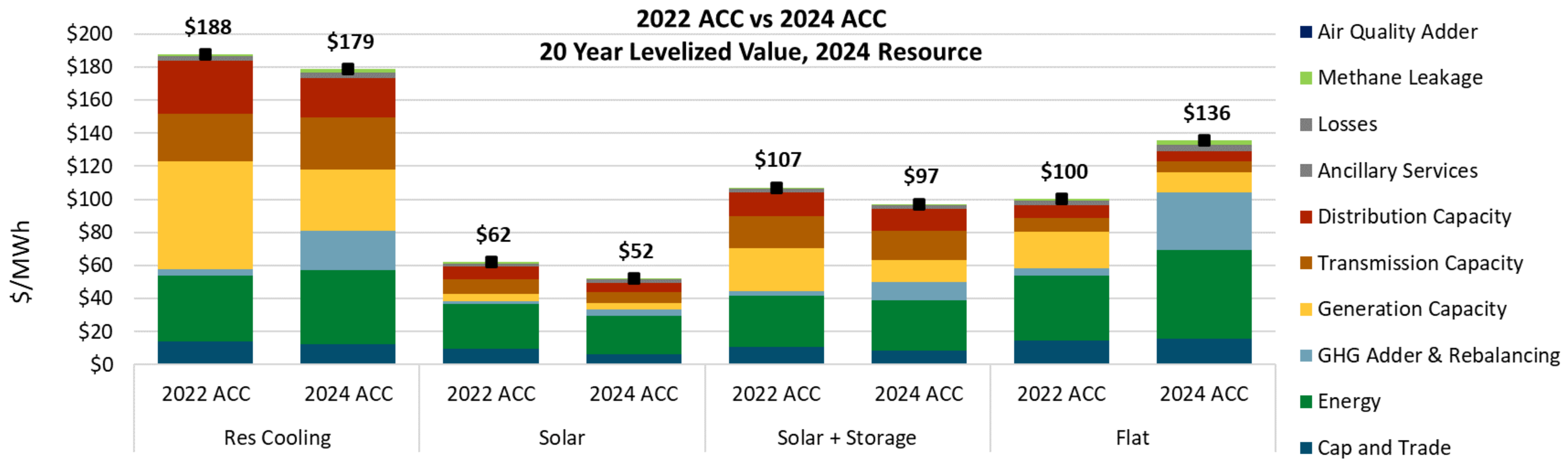
Energy Value More Time-dependent

Higher GHG Value

While flat avoided costs have increased, midday avoided costs have decreased compared to 2022 for load reducing DERs

- Flat avoided costs have increased but avoided costs during middle of the day have decreased
- Across end uses, GHG value increases while Generation Capacity value decreases compared to 2022 ACC

Avoided Costs of Example Load Reducing DER



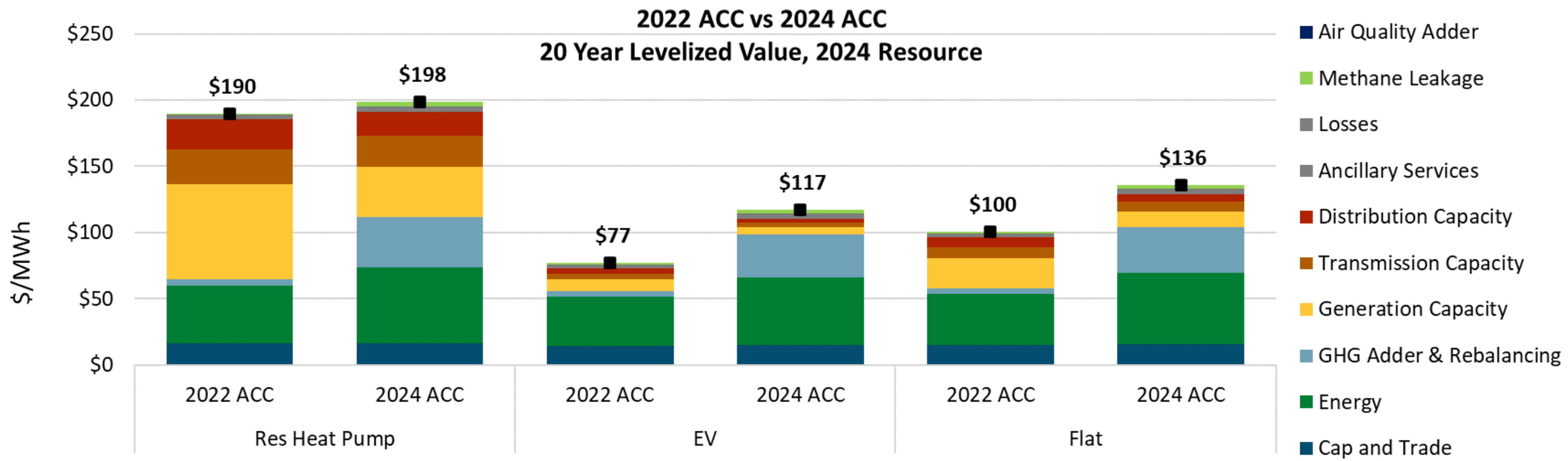
Results shown are for PG&E CZ12

Flat represents same amount of reduced load in all hours

Costs of electrification end uses have increased relative to 2022 ACC

- Residential heating electrification has slightly higher costs due to high Energy and 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 Energy and GHG Adder value in overnight and early morning hours

Marginal Costs of Example Load Increasing DERs



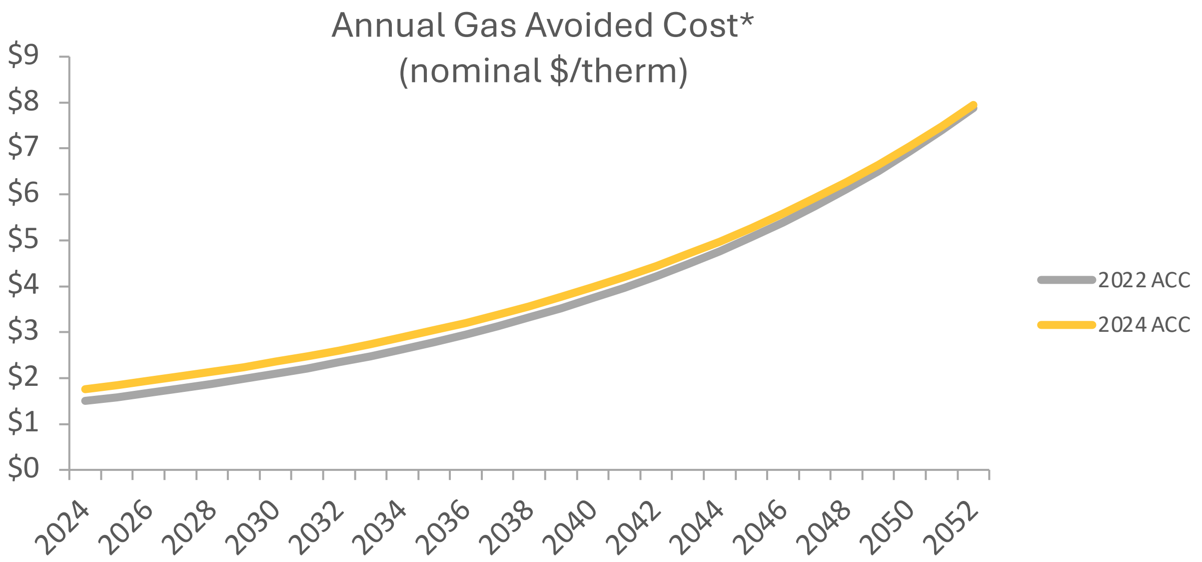
Results shown are for PG&E CZ12

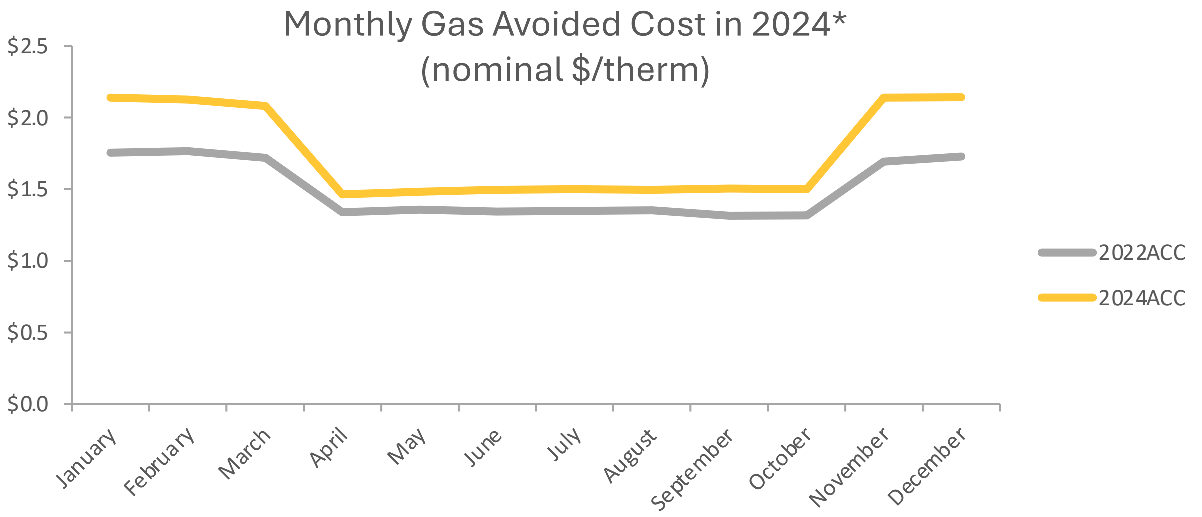
Flat represents same amount of increased load in all hours

Gas avoided costs are slightly higher than 2022 ACC

No methodology updates were made in the 2024 ACC Gas Model. Key data updates include:

1. IEPR gas price forecasts
   - Slight increase from 2022 ACC
2. Avoided Gas Infrastructure Costs (AGIC)
   - Updated based on new data from IOUs via data request
   - Some values increased and some decreased depending on IOU and infrastructure type
3. Gas transportation marginal costs and monthly allocation factors
   - Updated based on new data from IOUs via data request
   - Gas transportation marginal costs increased across IOUs
   - Final allocation between summer and winter is similar to 2022 ACC
4. IOU WACC
   - Decreased from 7.52% to 7.3%





* *for PG&E Residential Small Boiler with Flue Gas Recirculation*

SERVM Data Overview

Mounir Fellahi
Energy Resource Modeling
Energy Division

Overview and Summary

Staff performed backcasting to demonstrate ability to match pricing from 2021 and 2022

- Show major updates to inputs, major SERVM client changes
- Calibrate scarcity pricing levels to recent CAISO pricing trends
- Show backcasting comparisons (Heat rate and price patterns by month)

Forecast prices for 2024-2045 using TMY and SERVM model

- Energy and AS prices are elevated for first few years, then moderate after 2027, but escalate again in 2040 and 2045 due to rising electric demand
- Price trends are reasonable, and reflect predicted dispatch of the electric system
- LOLE trends – low in near term, much higher out to 2040 – decreased import levels and tightening supply-demand balance in external areas

Produce and analyze Loss of Load Expectation (LOLE) with regular and new storage dispatch routines

- New storage dispatch routine spreads LOLE to more hours and more months, highlights capacity value in a wider range of hours

Backcasting

Data Collection, Processing, and Adjustments

- **Data Collection Sources:**
  - **CAISO (2021-2022):** Electricity prices, demand, generation, imports/exports, solar, wind, hydro
  - **Natural Gas Intelligence (2021-2022):** Fuel prices
  - **ASQMD (2021-2022):** Generation units
- **Data Processing:**
  - **Methods:** Harvested via CAISO API, processed using R, Python, Excel
  - **Final Data:** Hourly averages for prices, demand, generation, imports/exports
- **Adjustments:**
  - **Initial Calibration:** Island mode, neighbor inclusion, output differences, iterative calibration
  - **Specific Adjustments:** Heat rate, transmission constraints, gas prices, GHG allowances
  - **Soft Cap:** Maximum price limit set at $1000/MWh, aligning with CAISO
  - **Scarcity Pricing:** Exponential decay function capped at $2000/MWh

SERVM Model Updates

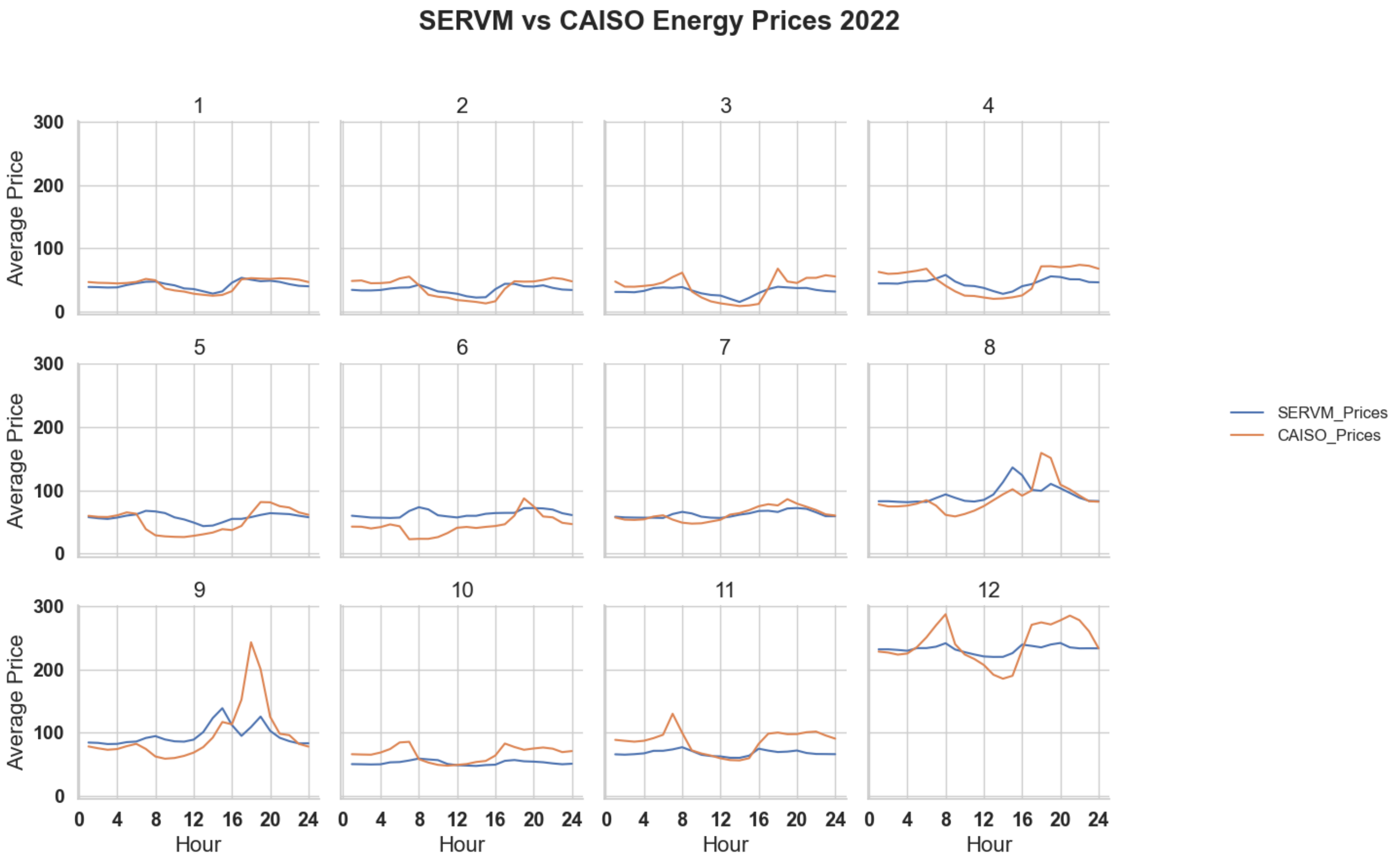
The relevant upgrades to the SERVM model since 2022 ACC are listed and briefly described below:

- Added NPV calculations to account for future year's system cost and reliability to impact the current year's decisions.
- New optional ORDC curves called Spin Price Floor and Regulation Up Price Floor. Users can specify these new curves to set minimum AS prices for Spin and Regulation Up.
- Storage Logic Updates - Updated the storage logic to clean up the synchronization of charging and discharging without the use of storage groups.
- Added ability to model daily fuel prices. If daily fuel prices are specified, it will override the monthly fuel prices. This is to simulate situations where there are fuel price shortages and spikes in the spot market, but not overall monthly commodity price increases.
- Pre-curtailment logic to curtail designated renewable units to limit the load ramp-up.
- Option to schedule storage based on chronological demand shape to shave demand (normal operation), or two new options related to dispatch on EUE days. Storage heuristics will be impacted for scarcity day and the storage units will follow the preliminary schedule.

Analysis of SERVM and CAISO Price Comparison

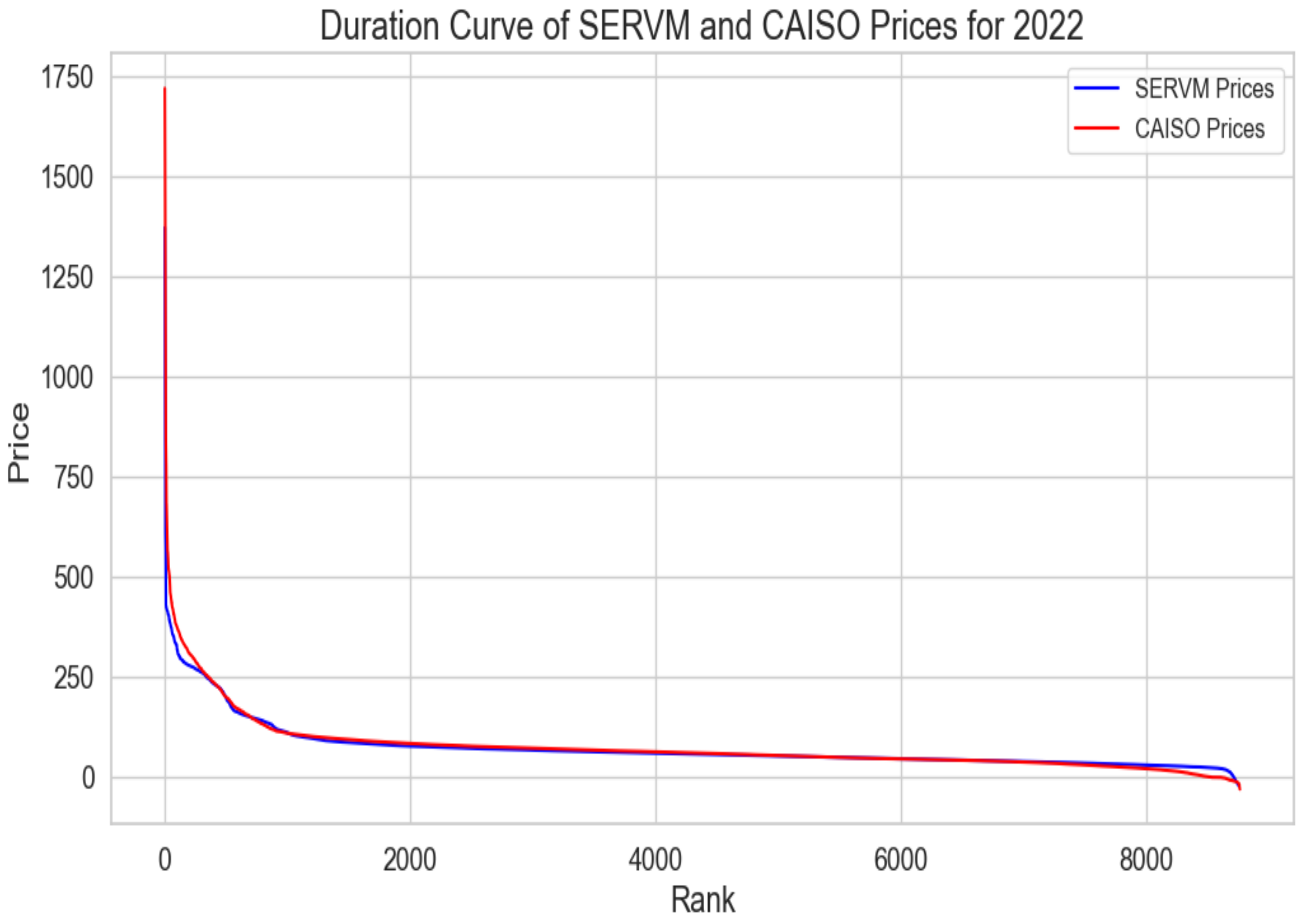
- **To benchmark and analyze SERVM results, staff:**
  - Performed comprehensive analysis of SERVM prices against CAISO actual prices for 2021 & 2022 (both energy and ancillary services)
  - Utilized statistical approaches, heat maps, and price benchmarking
  - Evaluated historical data to demonstrate distribution patterns and trends
  - Analyzed each hour of the day and each month of the year
  - Evaluated Implied Heat Rate and Duration Curves
  - Evaluated relationships and density distribution for SERVM and CAISO prices
  - Evaluated the major differences during low net load periods attributed to historical renewable production modeling
  - Contrasted variances between SERVM-generated and actual prices
  - Used error metrics such as Mean Absolute Error (MAE)

2022 Energy Price comparisons SERVM vs CAISO



- General trends of SERVM prices (blue lines) and CAISO prices (orange lines) are relatively aligned, indicating a good calibration of the model to actual market conditions.
- There is discrepancy in month 9, where SERVM prices diverge from CAISO prices during hour ending 18-19 due to the scarcity price curve construct.
- The SERVM model is generally well-calibrated.

2022 Energy Price comparisons SERVM vs CAISO Duration Curves



- The duration curves for SERVM prices (blue line) and CAISO prices (red line) show close alignment, indicating SERVM model accurately captures the overall distribution of market prices.
- At the higher end of the price range (left side of the graph), both curves rise sharply, indicating occasional high price events. The SERVM model slightly underpredicts these peak prices compared to CAISO.
- A majority of the time (middle and right side of the graph), the curves for SERVM and CAISO prices are almost identical, suggesting the model performs well in predicting prices during regular market conditions.
- The rank of prices (x-axis) shows the frequency distribution of prices between the two datasets is similar, with both curves flattening out towards lower prices as the rank increases.
- The duration curve indicates the SERVM model is well-calibrated to reflect CAISO market prices across most of the price range.

Forecasting

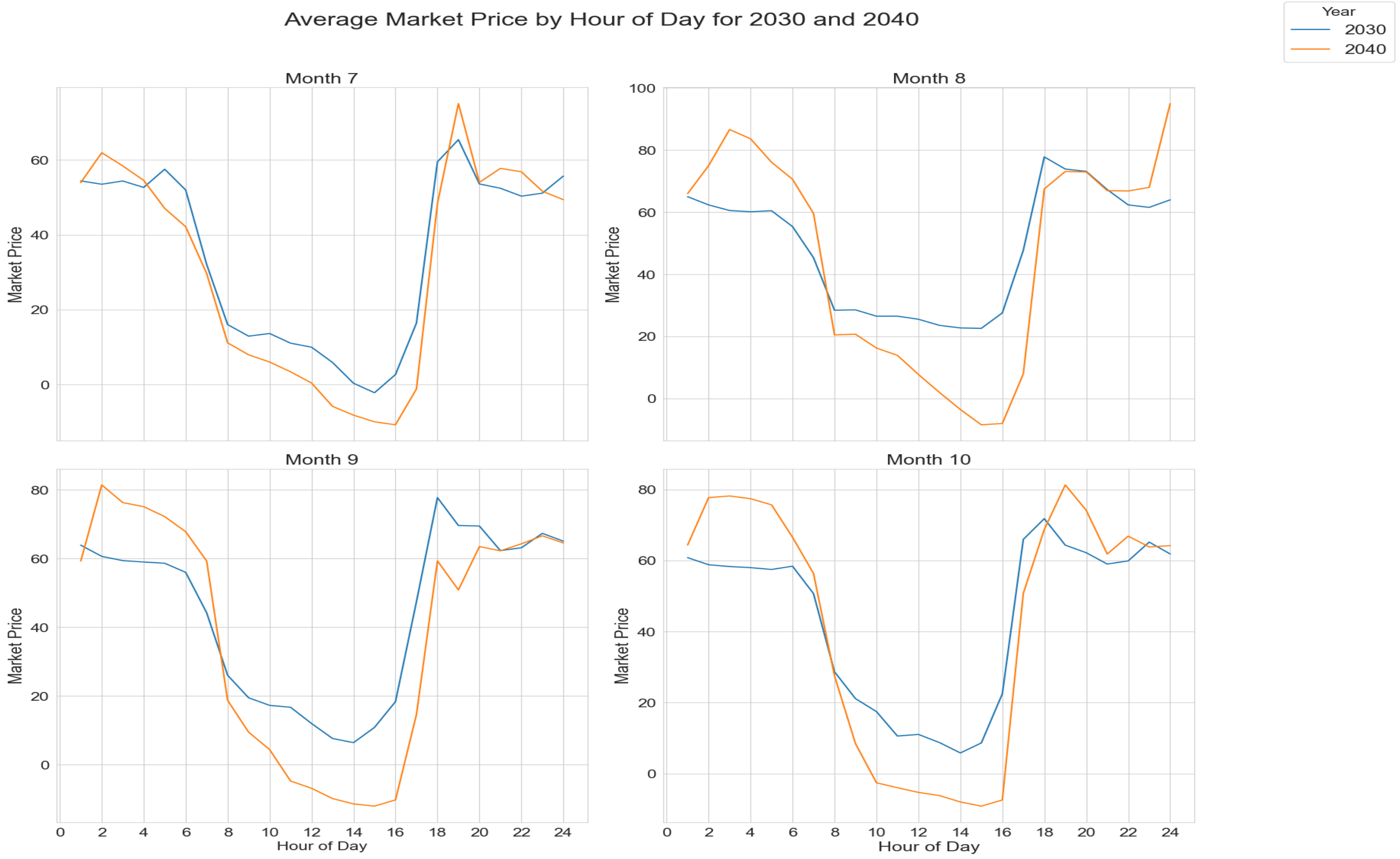
Forecasting Future Energy and Ancillary Services Prices

The forecasting involves several key elements:

- **Demand Forecast:** Utilized from the Integrated Energy Policy Report (IEPR).
- **Fuel Prices:** Sourced from NamGas prices.
- **Outage Data:** Utilized current outage data from SERVM to anticipate potential disruptions in power generation.
- **Supply Side Adjustments:** Made in line with the Integrated Resource Plan (IRP) forecast.
- **Weather Data:** 8760 strip based on weather data from a Typical Meteorological Year (TMY) for reference:

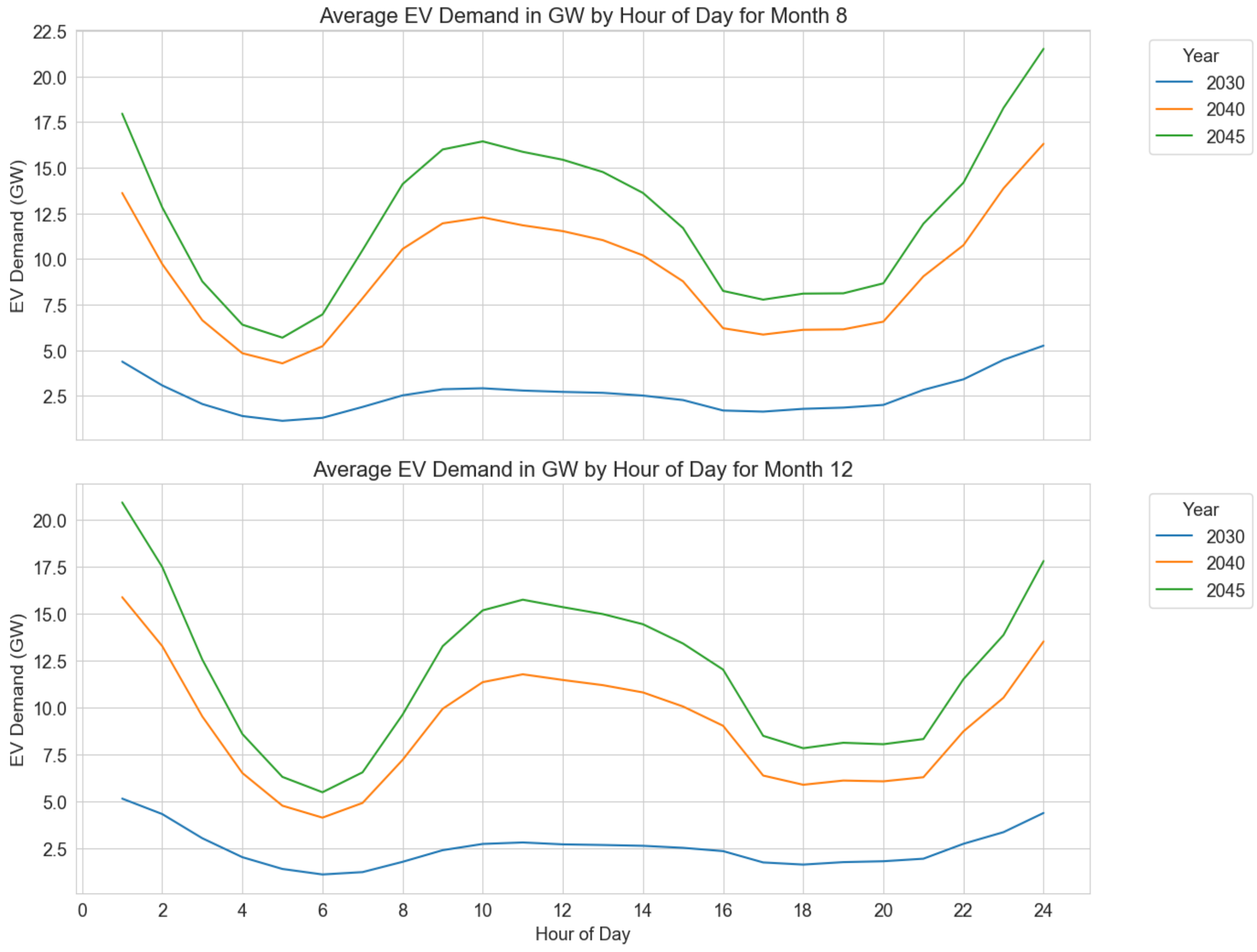
CTZ Weather Year	
Month	Year
1	2004
2	2008
3	2014
4	2011
5	2017
6	2013
7	2011
8	2008
9	2006
10	2012
11	2005
12	2004

Average Energy Price for 2030 and 2040



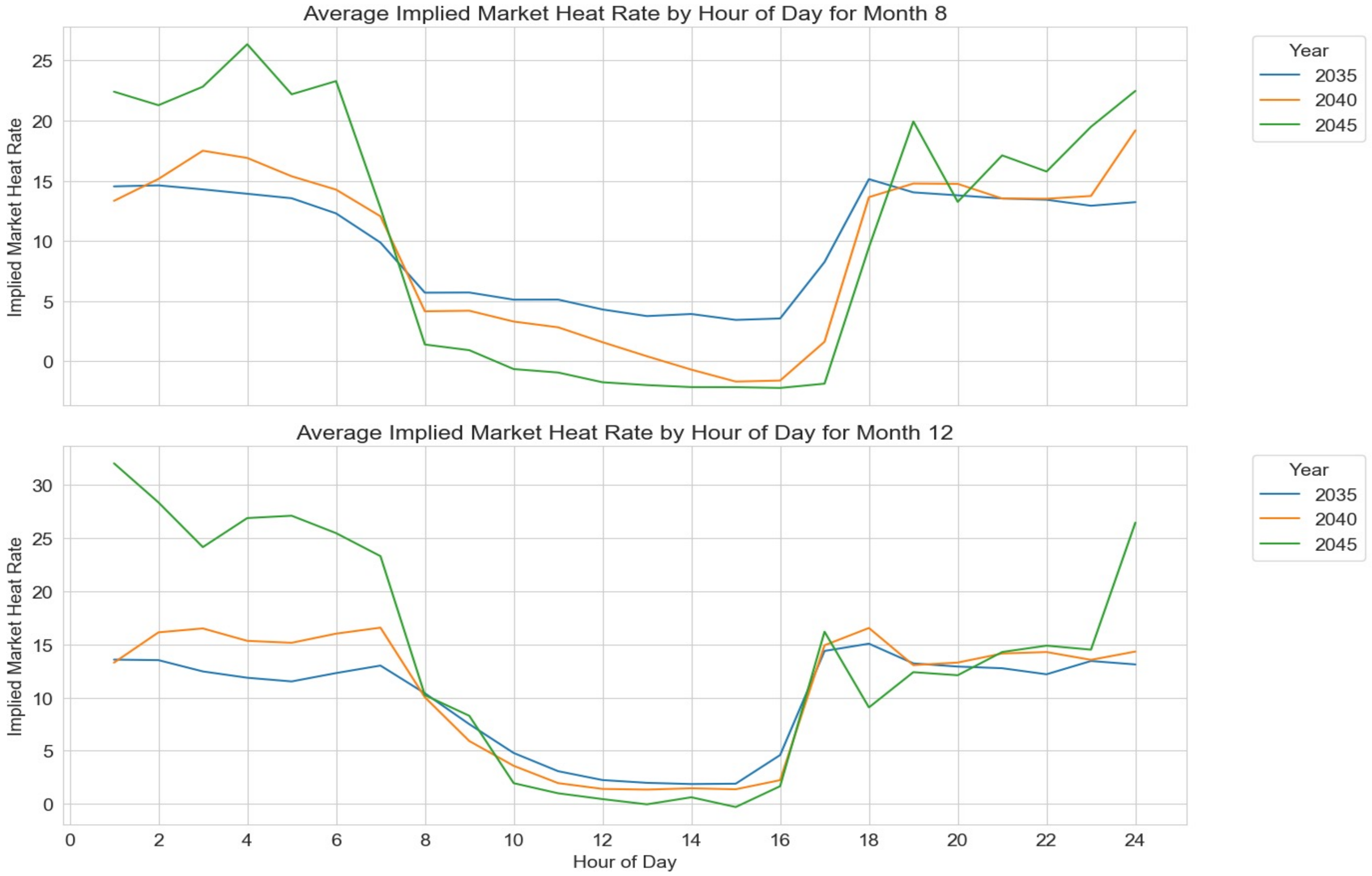
- **In ACC, costs have a floor at $0, meaning no costs go below 0$.**
- In 2030, prices peak in early morning and late afternoon to evening hours, corresponding to high demand times.
- Prices decrease during midday from 2030 to 2040 due to increased solar generation and increase at nighttime hours and early morning due to increased EV demand.
- Daily fluctuation is consistent with current patterns, reflecting typical demand cycles and renewable energy generation trends.

CAISO EV comparisons 2030, 2040, 2045



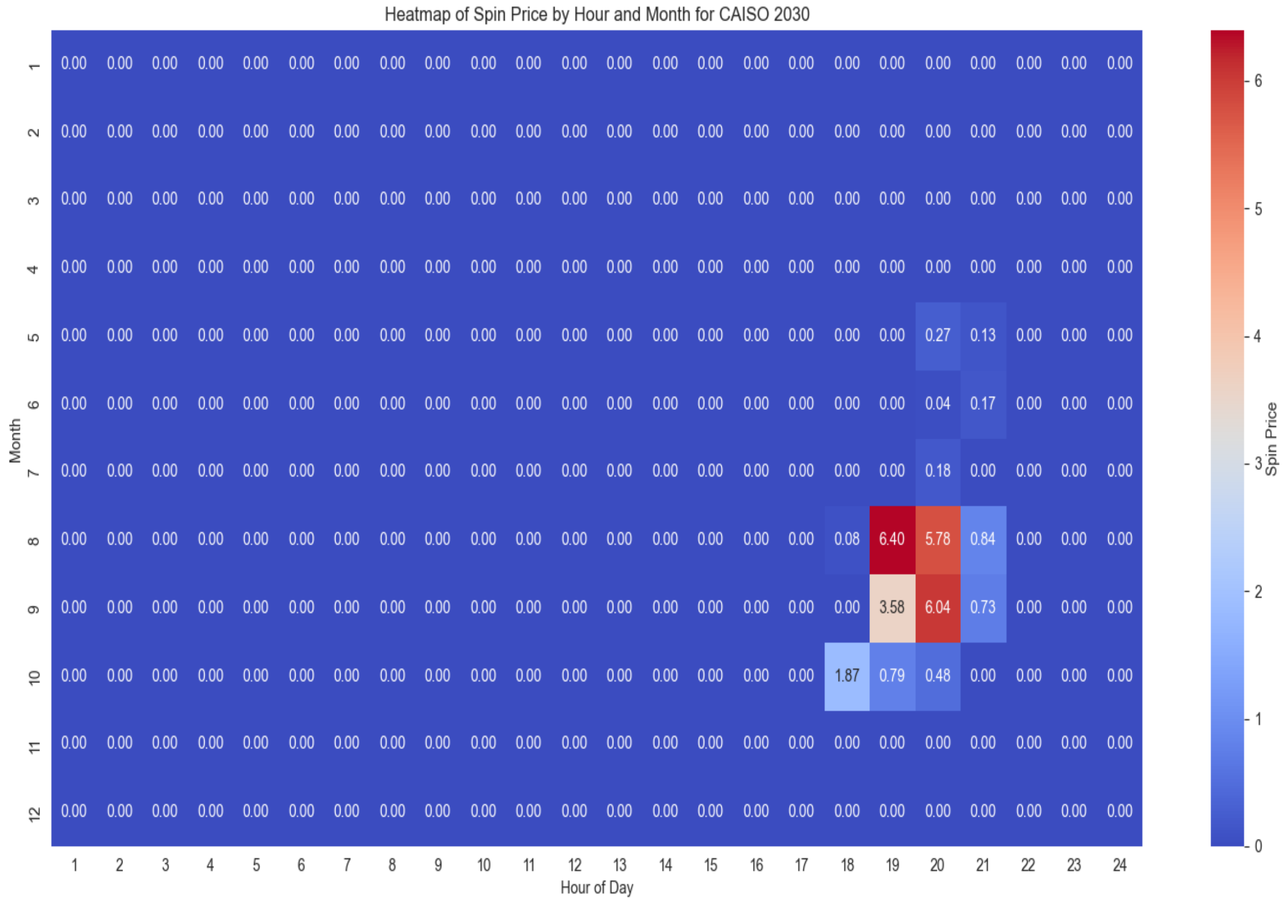
- The forecasted increase in electricity prices for 2040 can be attributed to the rising adoption of electric vehicles (EVs).
- As more consumers charge their EVs during off-peak hours, the overall demand for electricity at night surges.
- This shift in demand patterns ultimately influences the forecasted electricity prices particularly in later years.

CAISO Implied Heat Rate comparisons 2030, 2040, 2045



- Energy prices are strongly driven by increased thermal use and scarcity in the off-peak and overnight hours, hence the strong effect on EV charging demand.
- The higher implied market heat rates in 2040 reflect the additional thermal generation required to meet the increased off-peak demand due to EV charging.

2030 CAISO Spin Price



- Highest spin prices, reaching up $6.40 on average, occur during hours ending 18-21, particularly in months 8 and 9.
- Elevated prices are due to scarcity pricing, which increases prices when supply is tight, and demand is high to reflect the scarcity of available resources.
- Occurrence of high spin prices aligns with peak demand periods, indicating that scarcity pricing mechanisms are effectively capturing periods of tight supply and high demand.

Correlation of 2030 Energy Prices to Net Load

- The scatter plot of SERVM prices shows a strong positive correlation between market prices and net load, indicating that market prices increase as net load rises.
- The scatter plot reveals that higher net loads, which occur during periods of high demand, correspond with higher market prices, reflecting the increased strain on supply resources.
- Alignment in the scatter plot between SERVM prices and net load suggests the model accurately captures the relationship between net load and market prices, demonstrating good predictive accuracy.

Integrated Calculation of Generation Capacity and GHG Avoided Costs

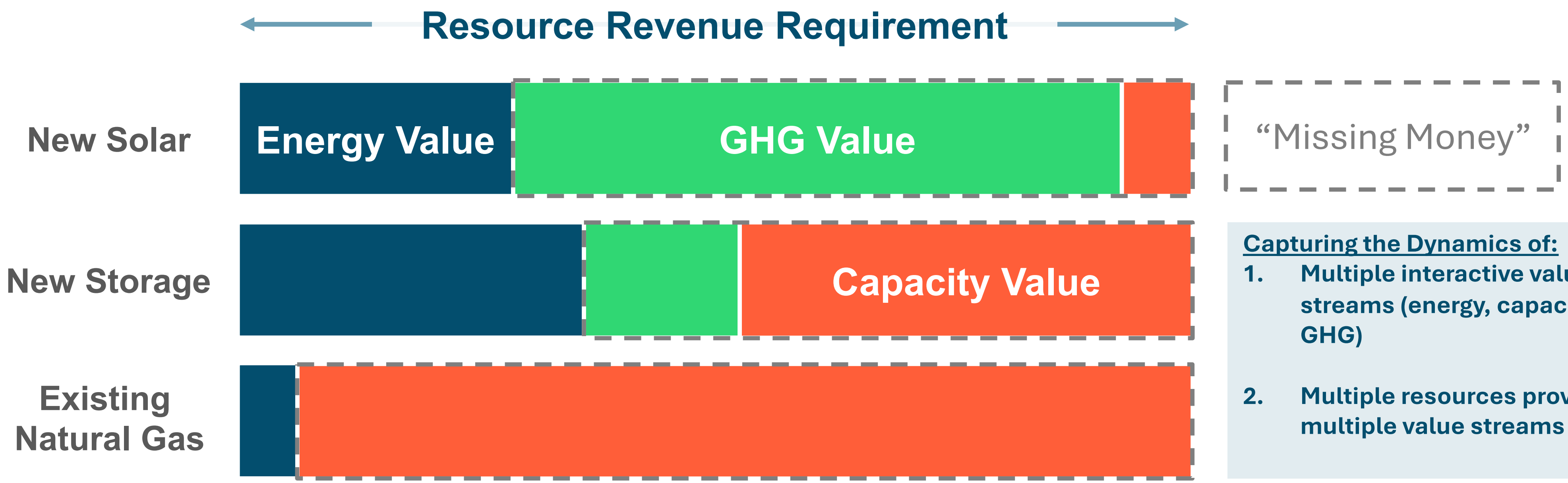
Energy+Environmental Economics

For each supply-side resource on the margin, total resource value should match its cost

+ Integrated Calculation uses three representative resources to derive GHG* and Capacity avoided costs

- New utility-scale solar
- New li-ion battery storage
- Existing gas plants

**Equivalent to GHG avoided costs consisting of cap-and-trade prices and GHG adder. Does not include GHG rebalancing component.*



Capturing the Dynamics of:

1. **Multiple interactive value streams (energy, capacity and GHG)**
2. **Multiple resources providing multiple value streams**

The Integrated Calculation solves annual capacity and GHG avoided costs simultaneously

+ For each supply-side resource on the margin, total resource value should be equal to resource cost on a net present value (NPV) basis:

Resource Costs = Energy & AS Value + Capacity Value + Greenhouse Gas Value

Capacity Value: Marginal ELCC x Capacity Avoided Cost

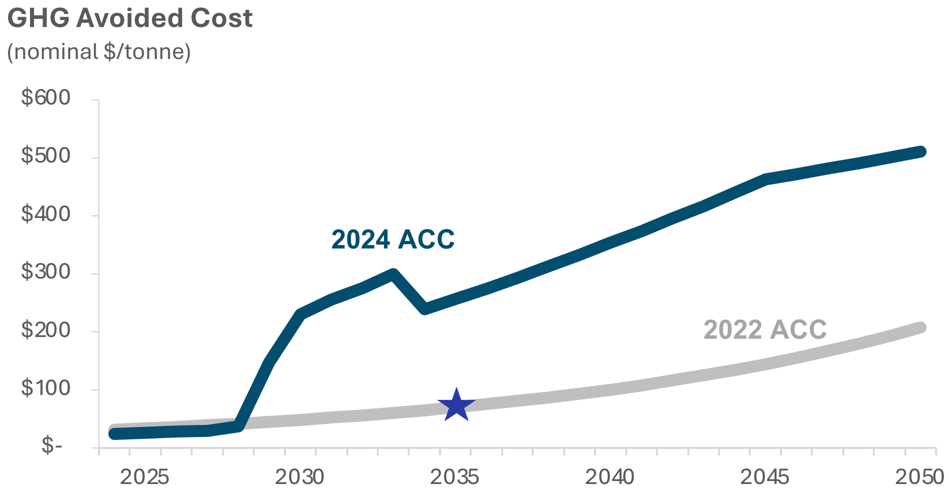
Greenhouse Gas Value: Marginal GHG Impact x GHG Avoided Cost

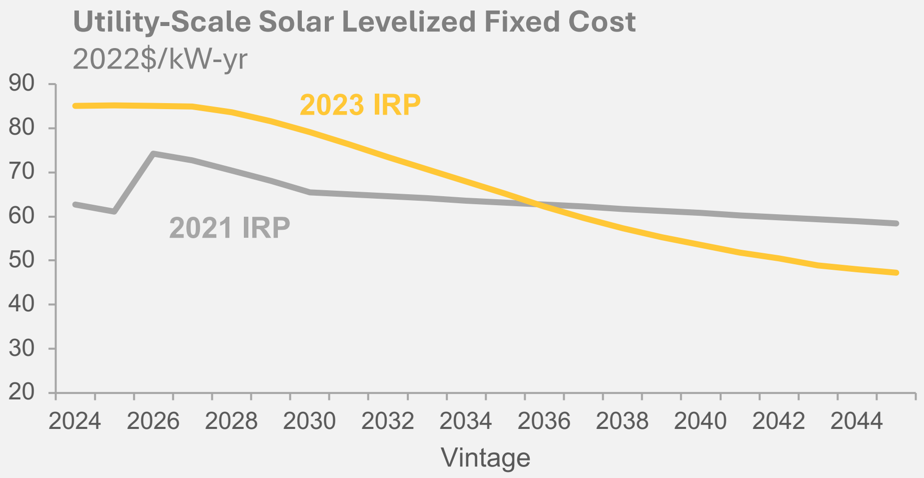
Inputs

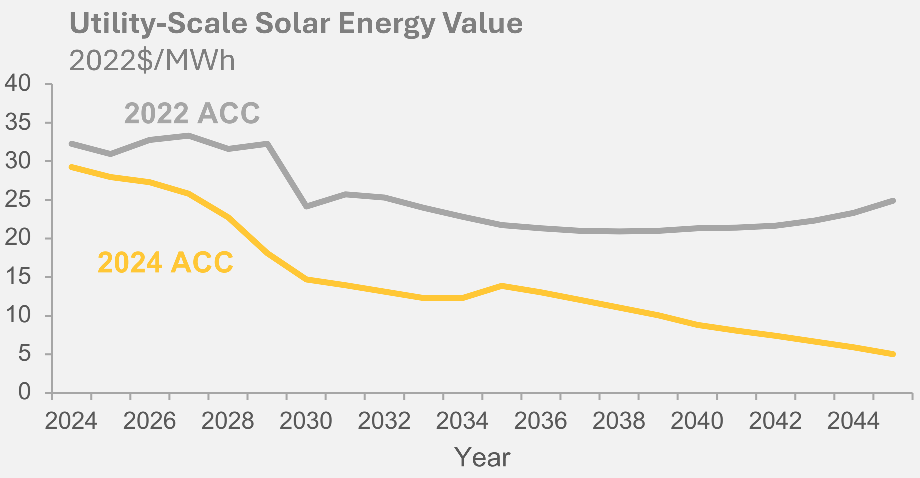
Resource Costs	Energy & AS Value	Marginal ELCC	Capacity Avoided Cost	Marginal GHG Impact	GHG Avoided Cost
Based on levelized cost assumptions in CPUC IRP proceeding	Calculated based on SERVM energy & AS prices	Derived from RESOLVE portfolio outputs	Calculated	Calculated based on SERVM energy prices	Calculated

Annual GHG avoided costs are higher than 2022 ACC

- **GHG avoided costs have increased due a combination of reasons, including:**
  - **Updated methodology**: 2022 ACC escalated/de-escalated one single value (RESOLVE shadow price in 2035) while 2024 ACC used the Integrated Calculation that explicitly calculates GHG and capacity avoided costs in each year.
  - **Higher costs**: Solar and storage costs have risen since the last IRP
  - **More stringent GHG target in IRP***: This require more costly resource investments. Higher solar penetration results in lower energy value and GHG contribution due to market saturation effect.



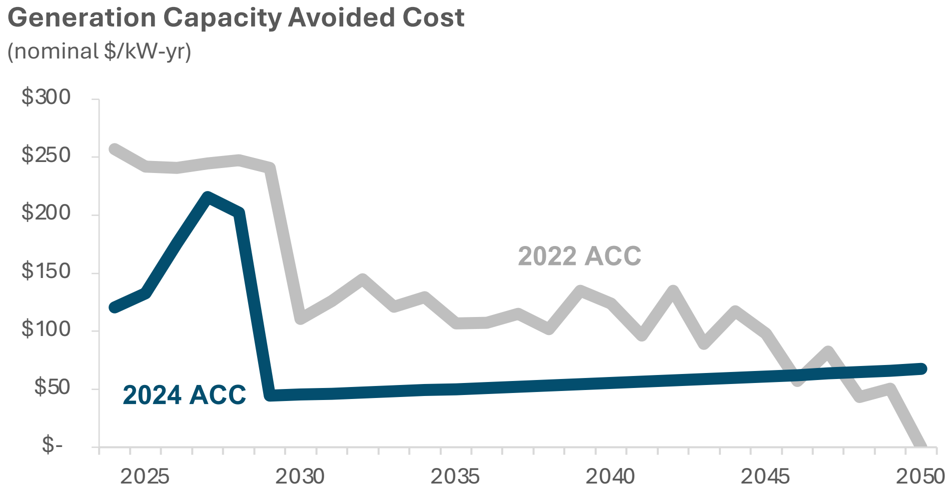


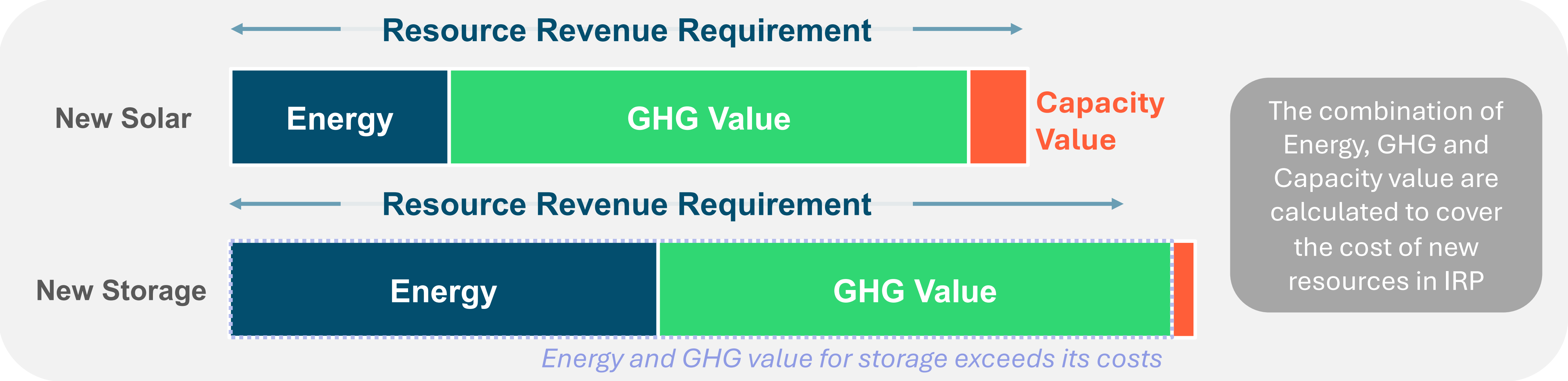


* *the latest IRP is meeting a GHG planning target of 25 MMT in 2035, more stringent than the 35 MMT by 2032 in 2021 IRP.*

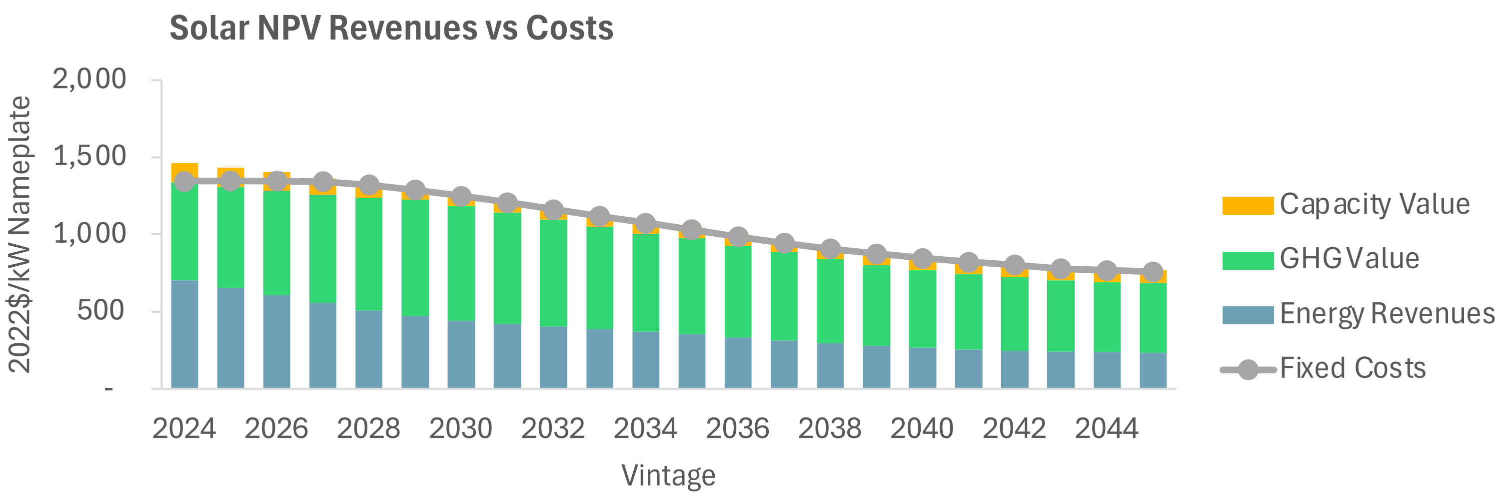
Annual capacity avoided costs are lower than 2022 ACC

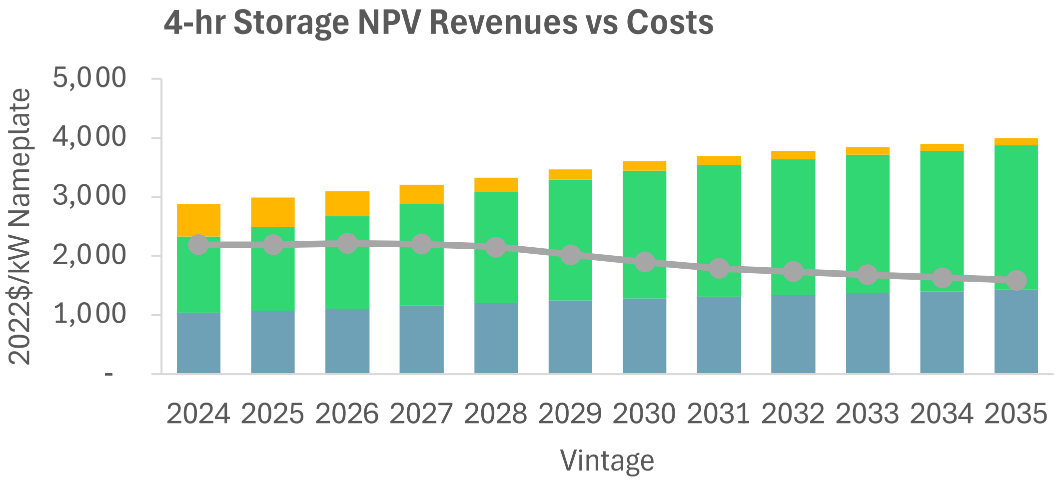
- Capacity avoided costs have decreased due to the interdependence between capacity, GHG and energy avoided costs
- Energy and GHG value exceeds storage costs, thereby driving down capacity avoided costs

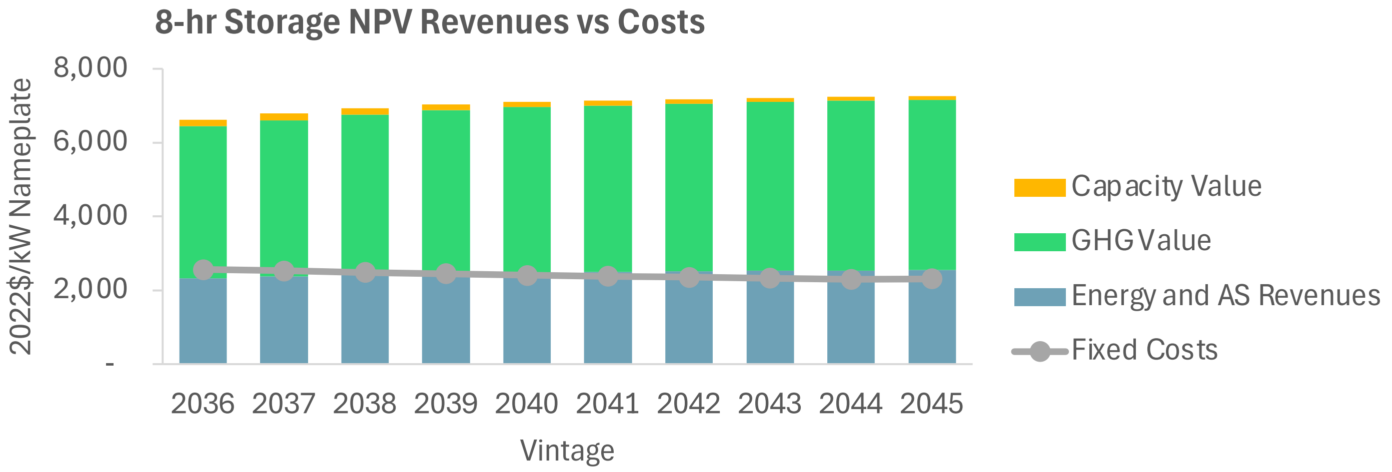




Energy, capacity and GHG values match solar costs but exceed storage costs



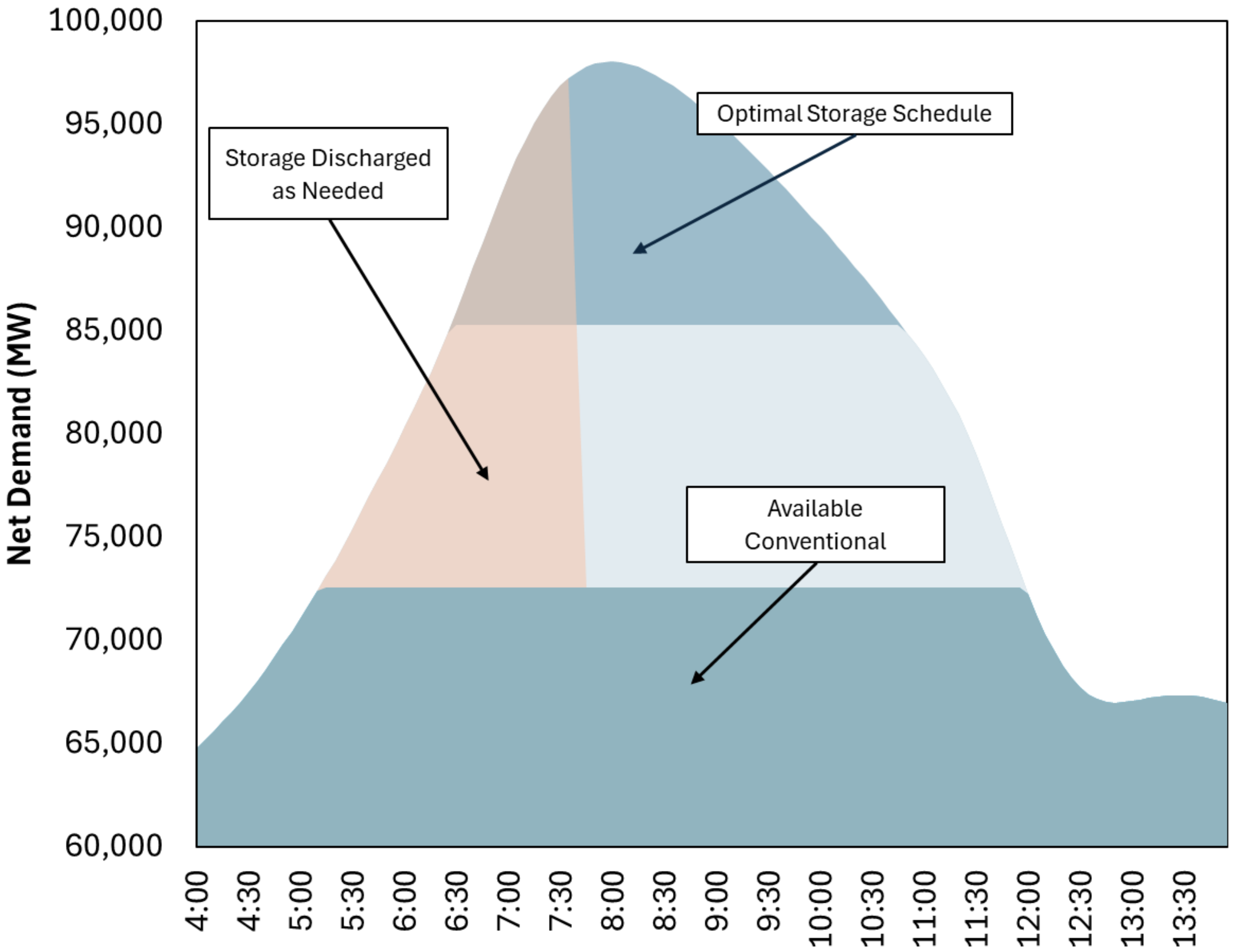




LOLE Study Results – Allocation of Generation Capacity Value to EUE Hours

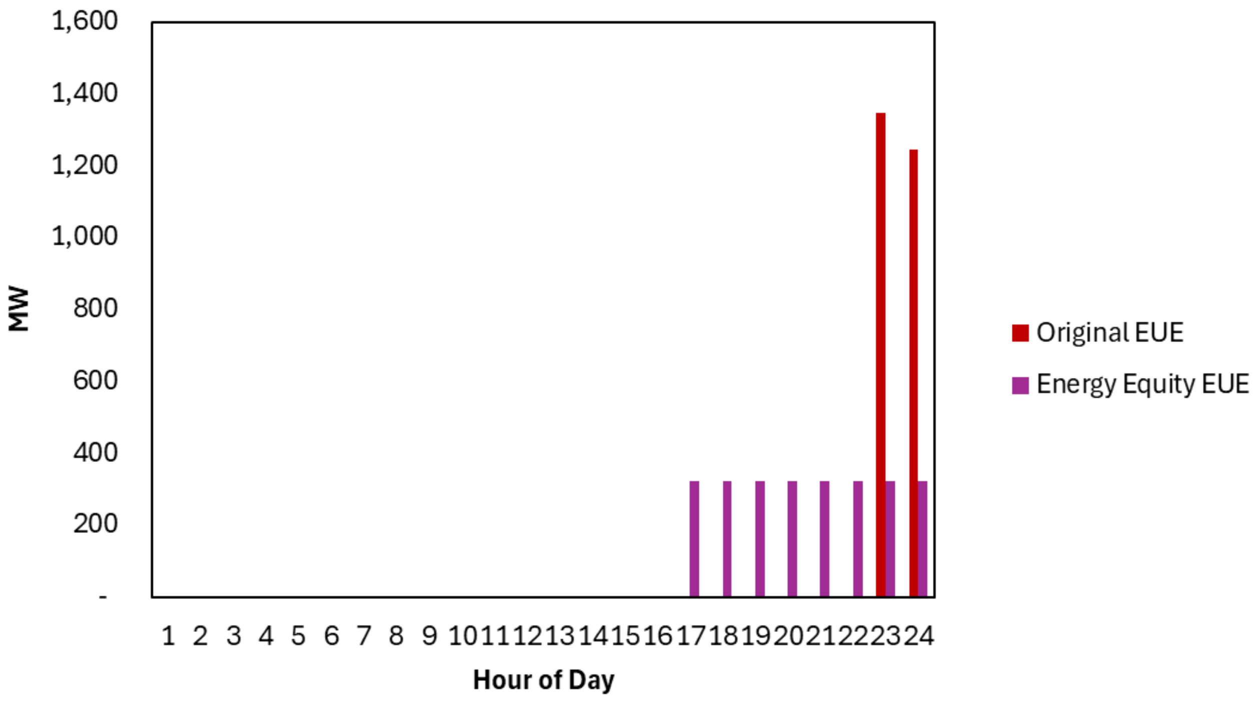
Storage Dispatch – Original Logic

- In base operation, SERVM creates a preliminary schedule for storage based on forecasted net load
- SERVM will schedule storage to charge during low net load and discharge during high net load to maximize reliability value
- Although storage is scheduled for net load peak periods, storage units may be dispatched earlier if inadequate resources are available



Storage Dispatch – Energy Equity Logic

- **SERVM models storage initially in economic dispatch**
- **The following post processing is performed at the end of the day where EUE occurs:**
  - Identify storage resources which were depleted during EUE
  - Determine time period where identified storage units began discharge
  - Spread the original EUE across the determined time period
- **This method recognizes that any incremental energy during this period would directly contribute to reducing EUE**
- **New energy equity logic spreads the EUE across hours 17-24 where storage was being dispatched instead of only hours 23 and 24**
  - Both cases have the same magnitude of EUE = 2,592 MWh



Original vs New Storage Dispatch Routine

Year	Hour Ending	July	August	September
2030 New Storage Dispatch	15	0	0.42673813	0.128021439
2030 New Storage Dispatch	16	0	2.871750591	1.180178275
2030 New Storage Dispatch	17	0.042673813	24.06949421	9.183991672
2030 New Storage Dispatch	18	0.384064317	45.69329246	38.26066676
2030 New Storage Dispatch	19	2.246323663	46.88815922	35.49333512
2030 New Storage Dispatch	20	1.464206478	49.07782052	17.53197888
2030 New Storage Dispatch	21	0.384064317	48.88728197	14.74349254
2030 New Storage Dispatch	22	0.384064317	48.89486618	14.47415283
2030 New Storage Dispatch	23	0.384064317	5.174736619	8.714579729
2030 New Storage Dispatch	24	0.341390504	4.578003173	4.762695198
2030 Original Storage Dispatch	15	0	0	0
2030 Original Storage Dispatch	16	0	0	0
2030 Original Storage Dispatch	17	0	0	0
2030 Original Storage Dispatch	18	0.04180245	0.006872613	29.8874687
2030 Original Storage Dispatch	19	0.915159918	0.829281214	20.12551046
2030 Original Storage Dispatch	20	0.5852343	40.07473871	13.96288372
2030 Original Storage Dispatch	21	0.12540735	106.9687022	19.01908519
2030 Original Storage Dispatch	22	0.79424655	127.9168904	40.10491016
2030 Original Storage Dispatch	23	4.30565235	3.938229223	16.02227649
2030 Original Storage Dispatch	24	0.87785145	1.636433061	3.311135308

- EUE values are observed primarily in the months of August and September.
- The highest EUE values, peaking around 127, are concentrated during the late afternoon to early evening hours (hour ending 18-21).
- Grid experiences tight supply and potential energy shortfalls during the late summer months, particularly in the late afternoon and early evening hours.
- This is due to high demand coinciding with lower availability of renewable energy sources like solar power as the sun sets.
- The new Energy Equity storage dispatch heatmap shows lower maximum hourly values, spread over greater number of hours.

Transmission and Distribution Avoided Costs

Energy+Environmental Economics

Transmission Avoided Cost Methodology

- **Calculation of transmission and distribution avoided costs remains consistent with the methods applied for the 2022 ACC**
- **Transmission avoided costs rely on utility General Rate Case filings and cost factor data for the Discounted Total Investment Method (DTIM) and Locational Net Benefits Analysis (LNBA)**

Component	Data Source	Calculations
Marginal Transmission Cost	Utility GRC Filings and supplemental data requests for marginal cost factors	Value set by prior CPUC ruling (PG&E); DTIM approach (SCE & SDG&E) and LNBA method for large projects (SCE)
Hourly Allocation of Transmission Avoided Capacity Costs	CAISO Energy Management dataset	Peak Capacity Allocation Factor (PCAF) method with values realigned to match temperatures in a typical weather year

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

Transmission calculations divide cost of planned investments by the forecasted load growth those investments address

- **The DTIM and LNBA method determine unit cost by dividing total investment by load growth**
  - DTIM focuses on projects designated to address systemwide need
  - The LNBA focuses on individual large projects and scales costs for the share of the system they cover
- **The Present Value $/kW value is then annualized into $/kW-year and O&M is added**
- **SDG&E relies on the DTIM approach, while SCE totals costs from both the DTIM and LNBA**

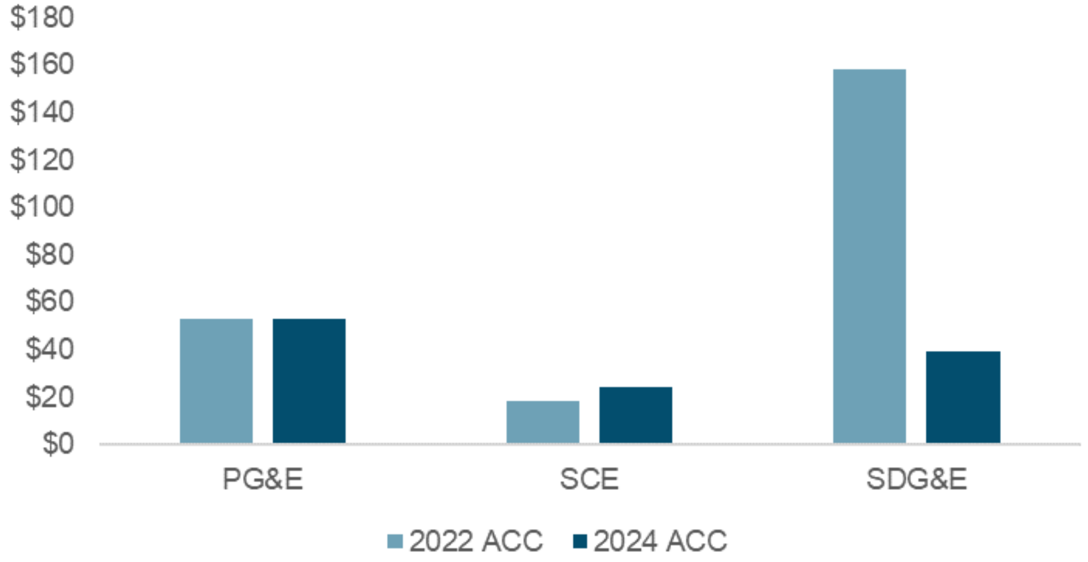
DTIM Method Example - SCE

Line	Component	Value	Notes
1	PV of Systemwide Investments ($M)	*$107.77*	[1]
2	PV of System Load Growth (MW)	*677*	[2]
3	PV of System Load Growth (kW)	*676,884*	[3] = [2] * 1000
4	Marginal Investment ($/kW)	*$159.21*	[4] = [1] * 10^6 / [3]
5	Annual MC Factor (%) *derived separately*	*8.67%*	[5]
6	Marginal Transmission Capacity Cost ($/kW-yr)	*$13.80*	[6] = [4] x [5]

Component (all $/kW-yr)	Value	Notes
Systemwide Projects	*$13.80*	*DTIM (above)*
Alberhill project averaged over SCE system	*$2.61*	*LNBA method*
Wildlife project averaged over SCE system	*$5.48*	*LNBA method*
Transmission O&M	$ 2.58	*Provided directly*
Total	***$ 24.47***	

Transmission avoided costs reflect the 'lumpiness' of investments

Marginal Transmission – 2022 ACC vs 2024 ACC (2023$)



ACC Vintage	PG&E	SCE	SDG&E
2022 ACC Update	$53.21	$18.25	$158.47
2024 ACC Update	**$53.21**	**$24.47**	**$39.64**

- **SCE Transmission value increased 34% while SDG&E value decreased by 75%**
  - PG&E Transmission value remains unchanged
- **SDG&E transmission was high in the 2022 ACC due to the "lumpy" nature of transmission investments**
  - The lumpiness is associated with the high cost and long useful life of transmission investments
- **In the 2024 ACC, costs are compared with the median change in demand forecasted through 2040**
  - These median value is only applied to the same years as the investments, but still reduces the impact of the "lumpiness" vs. using the immediate demand
  - This approach was applied in the 2022 ACC using a shorter forecast period

Distribution Avoided Cost Methodology

- **Distribution avoided cost calculation maintains the methodology described in the 2019 T&D White Paper**
  - Using updated GNA and DDOR inputs, the DER-deferrable overload capacity in the 2024 cycle is based on *the difference* between counterfactual and forecasted overloads, consistent with the White Paper
- **Distribution costs are now calculated separately for load increasing and load decreasing DERs and then averaged, rather than taking the net impact of all DERs**
  - This reduces the extreme sensitivity to differences between types of DERs forecasted to come online
  - Without this modification, avoided cost values could be negative or undefined under certain DER forecast scenarios. Negative values resulted this year, prompting the adjustment

Component	Data Source	Calculations
Near Term Marginal Distribution Cost	Utility Grid Needs Assessment (GNA) + Distribution Deferral Opportunities Reports (DDOR)	Use of 2019 T&D White Paper methodology to determine *incremental* overloads and resulting upgrade costs in a scenario without DER
Long Term Marginal Distribution Cost	Utility GRC Filings	Weighted grouping of GRC costs by climate zone (PG&E); Sum of cost components presented in filing (SCE, SDG&E)
Hourly Allocation of Distribution Avoided Capacity Costs	Utility GRC Phase II (PG&E, SCE); Utility Supplied Load Data (SDG&E)	PCAF-equivalent method (calculated by utilities for PG&E, SCE) with values realigned to match temperatures in a typical weather year

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

The White Paper distribution methodology determines the level of investment required in a future without incremental DER

PG&E Near-Term Marginal Distribution Calculation

Line		PG&E Load Decreasing DERs	PG&E Load Increasing DERs	Notes:
	Number of Overloads			
1	Actual Overloads	567	567	[1]
2	Counterfactual Overloads	809	435	[2]
3	Percentage of Overloads that can be Deferred by Load Transfers	20%	20%	From 2021 ACC
	Overload Capacity			
4	Actual Overloads (kW)	1,992,740	1,992,740	[4]
5	Counterfactual Overloads (kW)	2,281,663	1,393,994	[5]
5b	Estimated Overload Capacity Deferred by DERs (Includes Load Transfers) (kW)	288,923	-598,746	[5] - [4]
6	Estimated Overload Capacity Deferred by DER - Excluding Load Transfers (kW)	231,138	-478,997	[6] = [5b] x (100% - [3])
	Project & Planned Investment Costs			
7	Total Cost of Planned Investments in DDOR Filing ($)	$742,147,811	$742,147,811	[7]
8	Capacity Deficiency that Planned Investments Mitigate (kW)	$2,097,225	$2,097,225	[8]
9	Unit Cost of Deferred Distribution Upgrades ($/kW)	$353.87	$353.87	[9]* = [7] / [8]
	System Level Avoided Distribution Costs			
10	DER-Deferrable Capital Investment ($)	$81,793,266	-$169,503,262	[10] = [9] x [6]
11	Total Load Reduction from DER forecasted across all facilities, 2023-2027 (kW)	4,612,280	-8,738,321	[11]
12	Unspecified Distribution Deferral Value ($/kW of DER installed)	$17.73	$19.40	[12] = [10] / [11]
13	Marginal Distribution Cost Factor ('IOU Specific RECC') (%)	8.32%	8.32%	[13]
14	Capacity Deferral Value ($/kW of DER installed-yr)	$1.48	$1.61	[14] = [12] * [13]
	O&M Distribution Costs			
15	O&M Deferral Value ($/kW-yr)			[15]
16	O&M Deferral Value ($/kW of DER installed -yr)			[16] = [15] * [6] / [11]
17	Unspecified Marginal Cost ($/kW of DER installed-yr)	$1.48	$1.61	[17] = [14] + [16]

O&M Deferral value is not listed here for PG&E because it is added in earlier via PG&E's marginal cost factor

+ **Marginal distribution inputs are focused on deferrable capacity constraints**
  - These are measured in terms of system overloads and planned upgrades
+ **We compare forecasted vs. 'counterfactual' overloads to find the level of otherwise-required investment deferred by DERs**
  - Counterfactual overloads are those estimated to occur if the DER forecasted on the system is *Not* built
  - Counterfactual overload capacity is determined by subtracting anticipated DER capacity out of the planning forecast and calculating the impact on overloads
+ **Difference in overload capacity x unit cost of upgrades = total DER-deferrable investment**
  - This is divided by the DER forecast kW and annualized into a $/kW-year

The White Paper distribution methodology determines the level of investment required in a future without incremental DER

PG&E Near-Term Marginal Distribution Calculation

Calculations are now separated for feeders with decreasing vs increasing load from DERs

Line		PG&E Load Decreasing DERs	PG&E Load Increasing DERs	Notes:
	Number of Overloads			
1	Actual Overloads	567	567	[1]
2	Counterfactual Overloads	809	435	[2]
3	Percentage of Overloads that can be Deferred by Load Transfers	20%	20%	From 2021 ACC
	Overload Capacity			
4	Actual Overloads (kW)	1,992,740	1,992,740	[4]
5	Counterfactual Overloads (kW)	2,281,663	1,393,994	[5]
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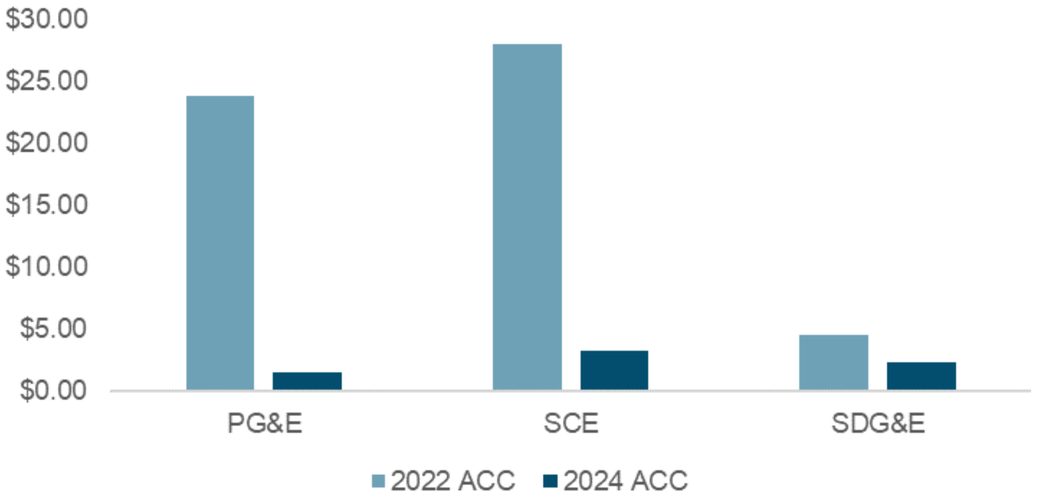
6	Estimated Overload Capacity Deferred by DER - Excluding Load Transfers (kW)	*231,138*	*-478,997*	[6] = [5b] x (100% - [3])
	Project & Planned Investment Costs			
7	Total Cost of Planned Investments in DDOR Filing ($)	$742,147,811	$742,147,811	[7]
8	Capacity Deficiency that Planned Investments Mitigate (kW)	$2,097,225	$2,097,225	[8]
9	Unit Cost of Deferred Distribution Upgrades ($/kW)	*$353.87*	*$353.87*	[9]* = [7] / [8]
	System Level Avoided Distribution Costs			
10	DER-Deferrable Capital Investment ($)	*$81,793,266*	*-$169,503,262*	[10] = [9] x [6]
11	Total Load Reduction from DER forecasted across all facilities, 2023-2027 (kW)	4,612,280	-8,738,321	[11]
12	Unspecified Distribution Deferral Value ($/kW of DER installed)	*$17.73*	*$19.40*	[12] = [10] / [11]
13	Marginal Distribution Cost Factor ('IOU Specific RECC') (%)	8.32%	8.32%	[13]
14	Capacity Deferral Value ($/kW of DER installed-yr)	*$1.48*	*$1.61*	[14] = [12] * [13]
	O&M Distribution Costs			
15	O&M Deferral Value ($/kW-yr)			[15]
16	O&M Deferral Value ($/kW of DER installed -yr)			[16] = [15] * [6] / [11]
17	Unspecified Marginal Cost ($/kW of DER installed-yr)	*$1.48*	*$1.61*	[17] = [14] + [16]

O&M Deferral value is not listed here for PG&E because it is added in earlier via PG&E's marginal cost factor

- **Marginal distribution inputs are focused on deferrable capacity constraints**
  - These are measured in terms of system overloads and planned upgrades
- **We compare forecasted vs. 'counterfactual' overloads to find the level of otherwise-required investment deferred by DERs**
  - Counterfactual overloads are those estimated to occur if the DER forecasted on the system is *Not* built
  - Counterfactual overload capacity is determined by subtracting anticipated DER capacity out of the planning forecast and calculating the impact on overloads
- **Difference in overload capacity x unit cost of upgrades = total DER-deferrable investment**
  - This is divided by the DER forecast kW and annualized into a $/kW-year

Near-term distribution costs sharply decline but are tempered by constant long-term values

Near-Term Marginal Distribution – 2022 ACC vs 2024 ACC (2023$ / kW-yr)



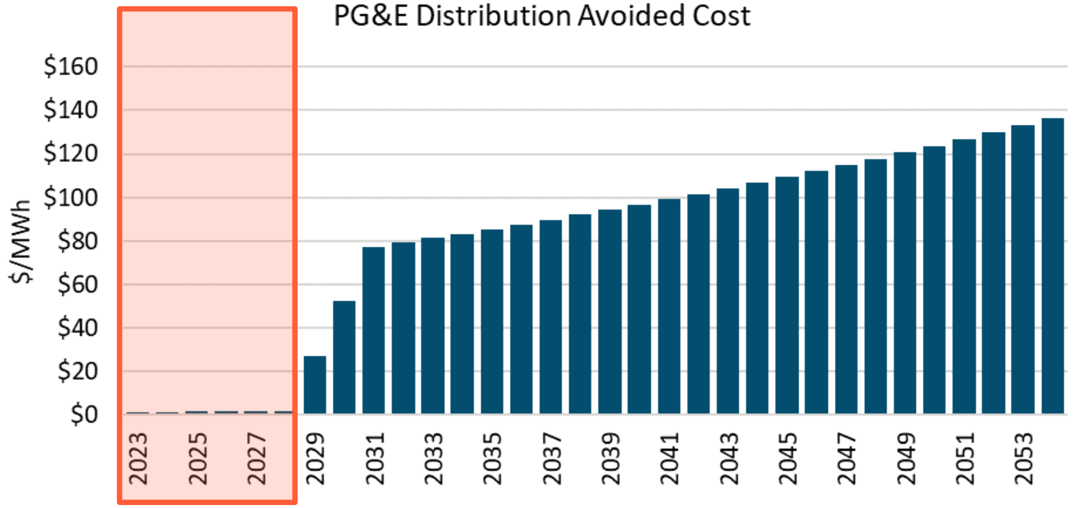
Near-Term Marginal Distribution

ACC Vintage	PG&E	SCE	SDG&E
2022 ACC Update	$23.85	$28.02	$4.53
2024 ACC Update	**$1.54**	**$3.34**	**$2.38**

Long-Term Marginal Distribution

ACC Vintage	PG&E	SCE	SDG&E
2022 *and* 2024 ACC Updates	**$57.29**	**$189.53**	**$89.51**

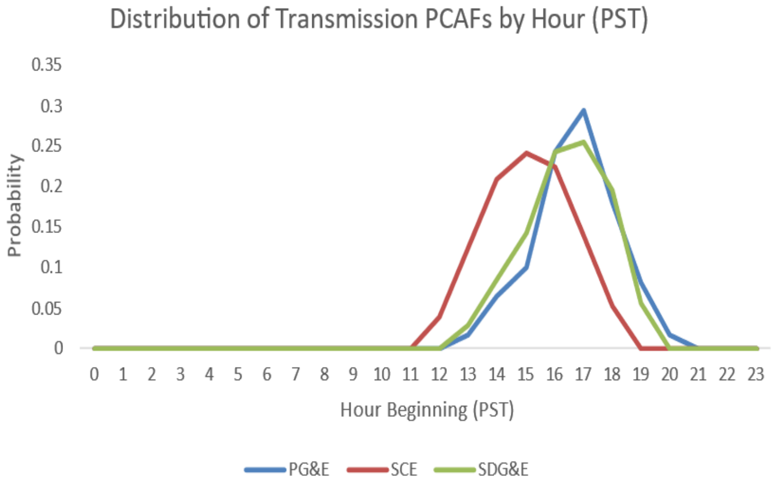
- **Near-term distribution avoided costs decrease significantly from the 2022 ACC**
  - Costs are now of a similar magnitude for all three utilities
- **Long-term values from GRC filings remain unchanged for the 2024 ACC**
  - *As a result, levelized costs see a relatively minor reduction*



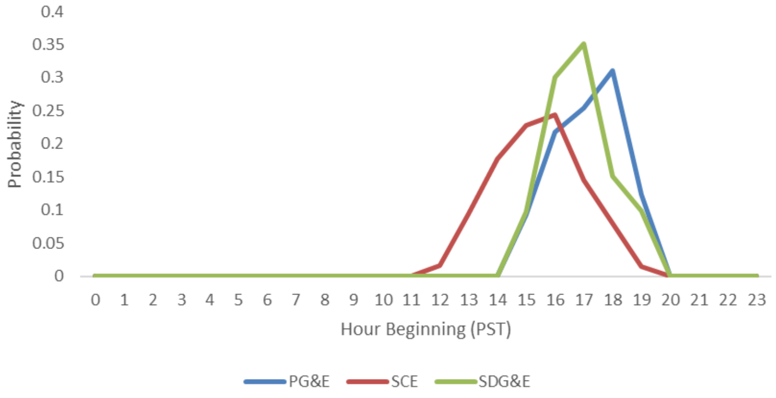
Allocation factors are based on recent load data and show minor variation from the 2022 ACC

Transmission PCAFs

2022 ACC



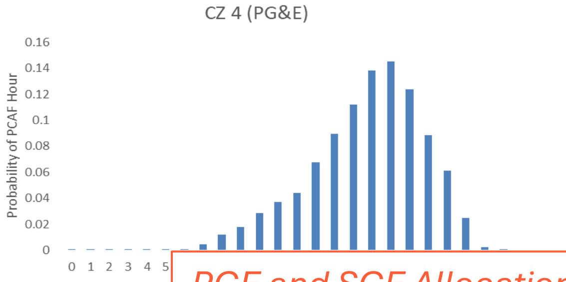
2024 ACC

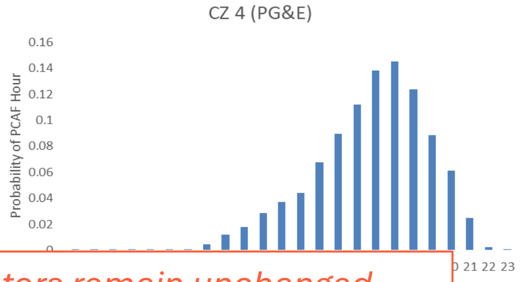


Distribution PCAFs

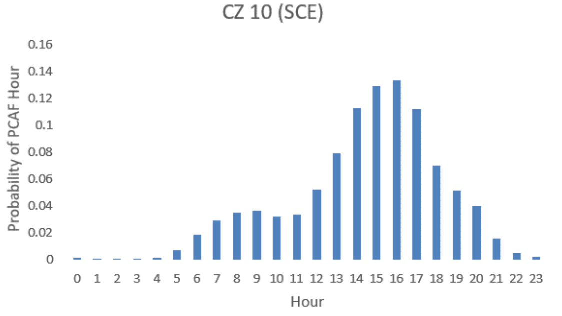
2022 ACC

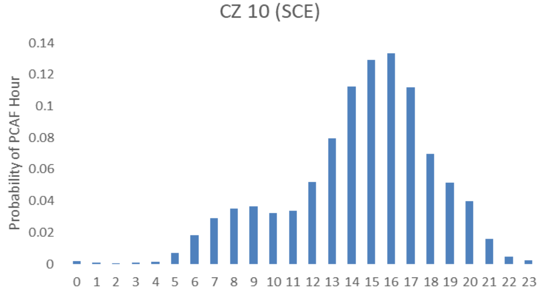
2024 ACC

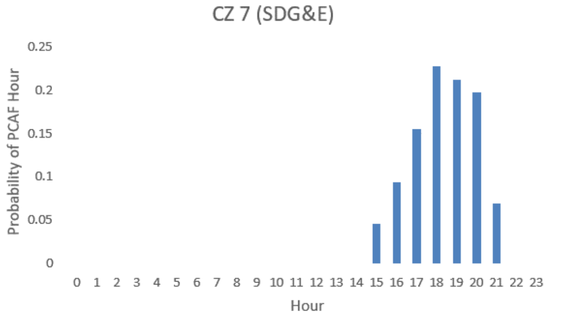


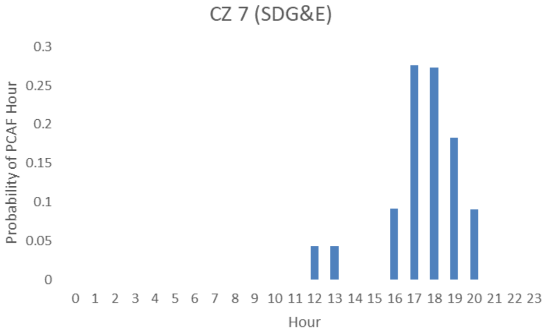


PGE and SCE Allocation factors remain unchanged









Societal Cost Test Methodology and Results

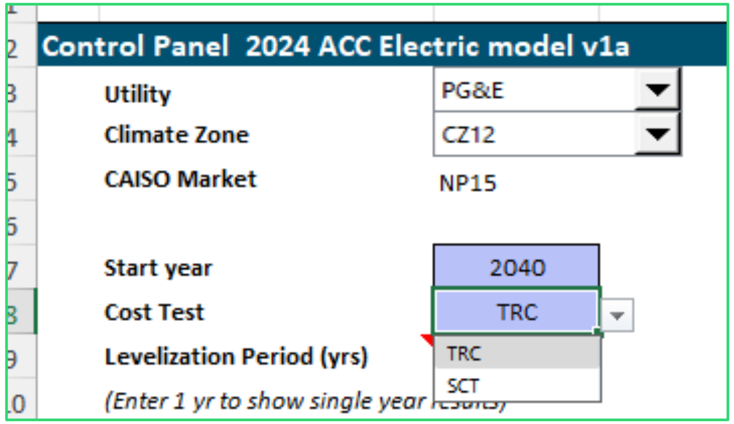
Energy+Environmental Economics

2024 ACC now outputs Societal Cost Test (SCT) perspectives

- The 2024 ACC includes a Societal Cost Test (SCT) option for both Electric and Gas models
- The base ACC is now referred as Total Resource Cost Test (TRC) option

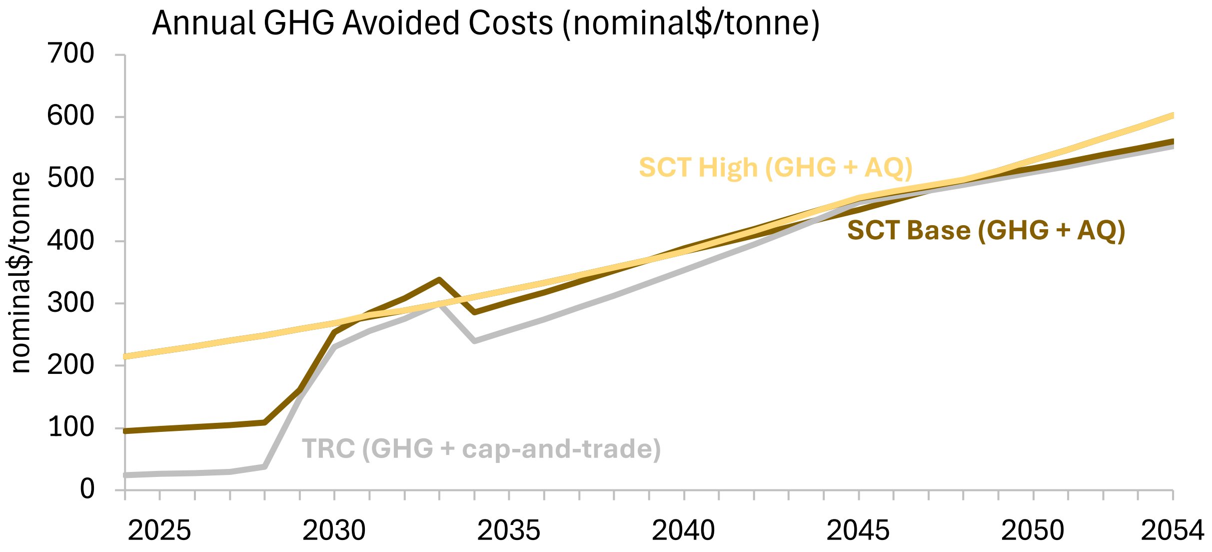
	ACC TRC	ACC SCT
GHG Avoided Costs	Cap-and-trade allowance prices	Social cost of carbon (base and high)
Discount Rate	7.3% (IOU WACC)	3%
Air Quality Adder	NO	YES
Methane Leakage Rate	0.6%	2.3%

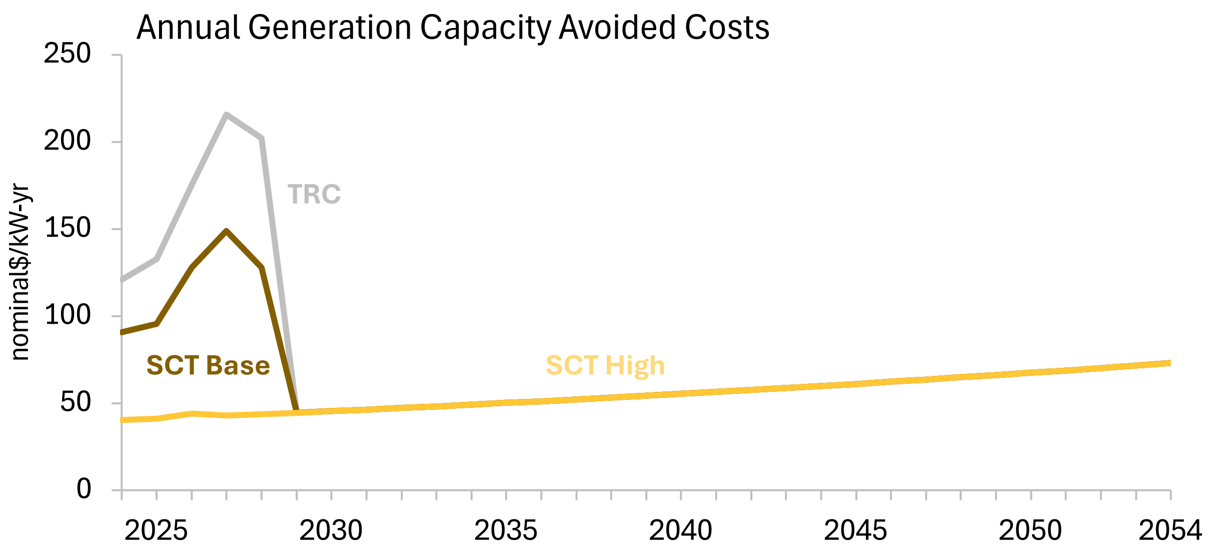
SCT included as a toggle in 2024 ACC



SCT GHG avoided costs are higher than TRC while capacity avoided costs are lower

- **SCT annual GHG avoided costs (before rebalancing) are higher than TRC due to**
  - Higher floor (set by Social Cost of Carbon (SCC) and Air Quality Adder)
  - Lower discount rate
- **GHG avoided costs are higher than the floor in SCT Base while follow closely to the floor in SCT High**
- **SCT capacity avoided costs are lower than TRC due to the inter-dependence between GHG and generation capacity avoided costs**





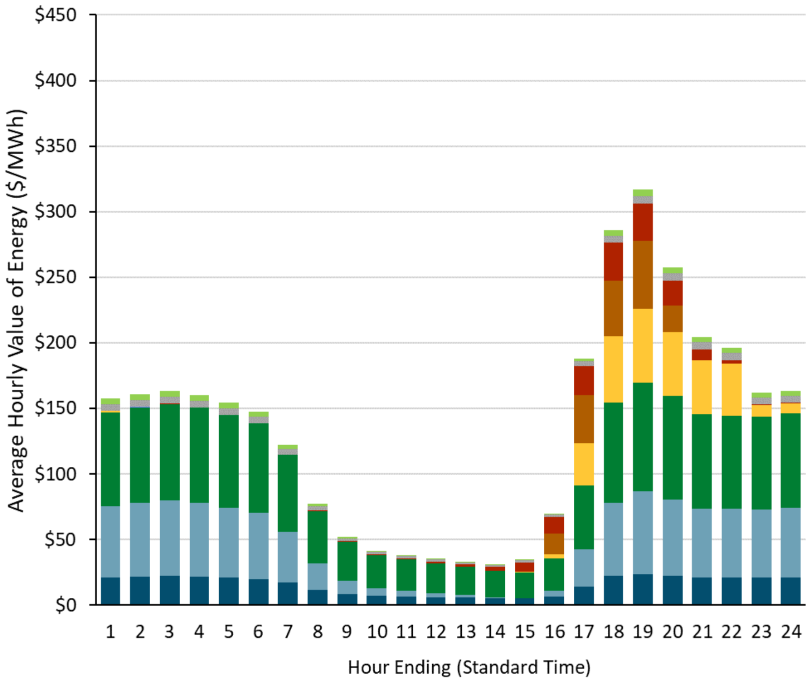
Hourly Average Avoided Costs – TRC vs. SCT

20-year Levelized Value for 2024 Resource

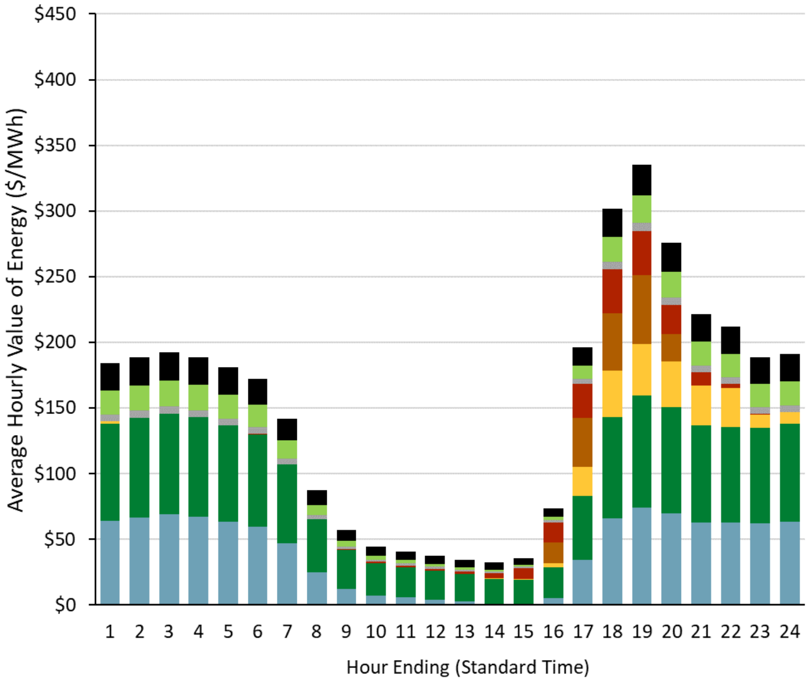
- SCT has higher GHG Adder and lower Generation Capacity value
- Increased Methane Leakage and Air Quality Adders have most significant impact on overall avoided costs

Air Quality Adder
Methane Leakage
Losses
Ancillary Services
Distribution Capacity
Transmission Capacity
Generation Capacity
Energy
GHG Adder & Rebalancing
Cap and Trade

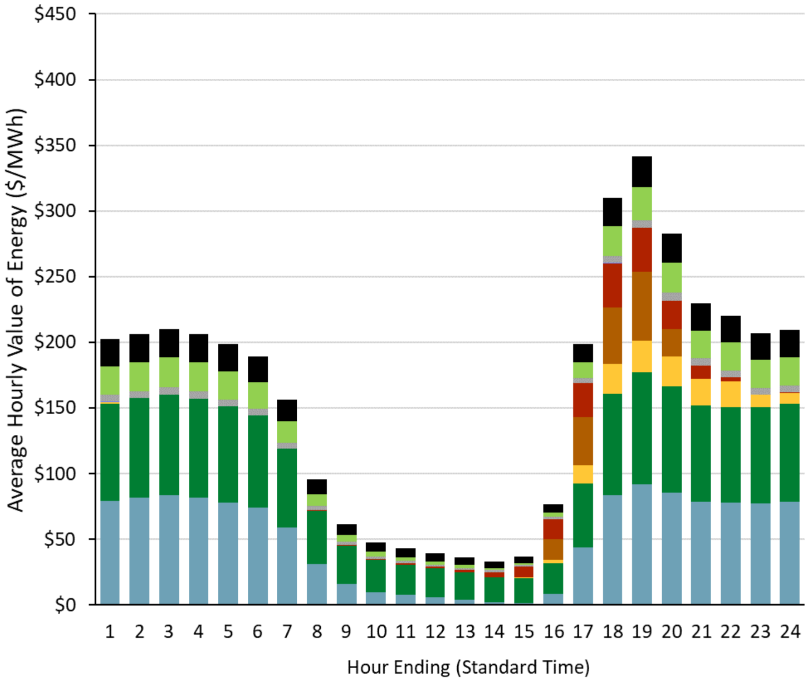
2024 ACC - TRC



2024 ACC – SCT with SCC Base



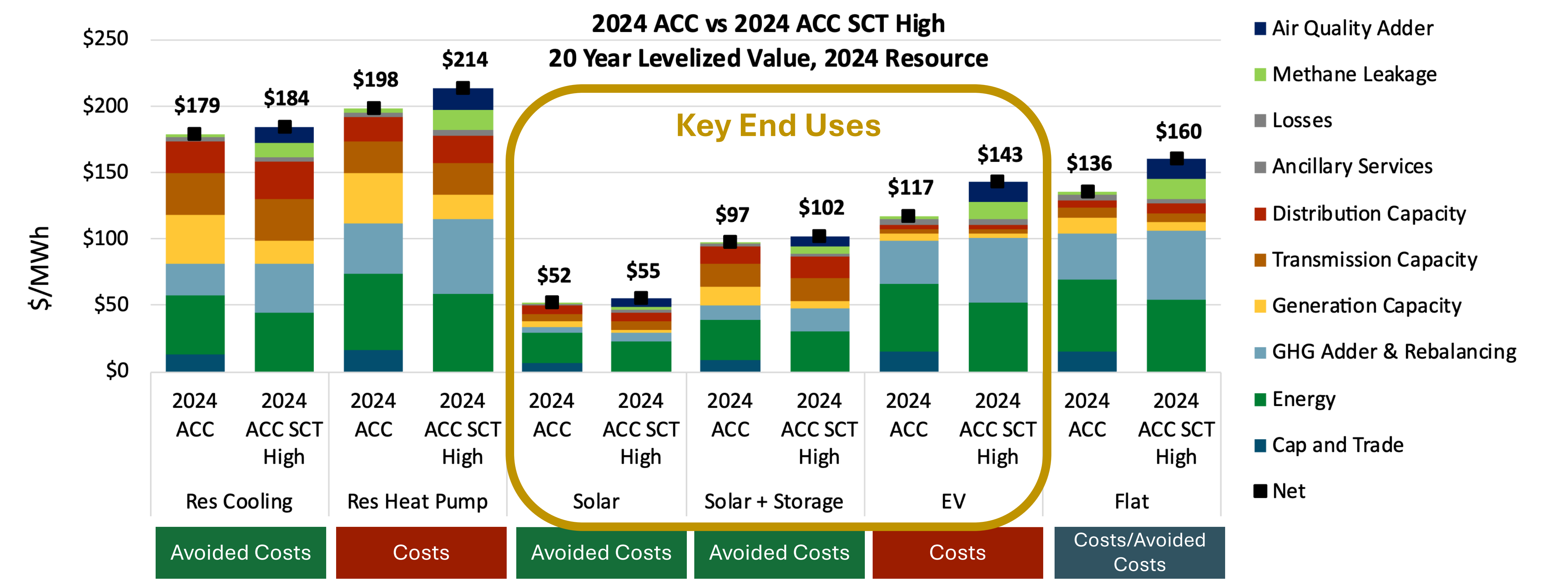
2024 ACC – SCT with SCC High



Societal Total Avoided Costs by End Use

2024 ACC TRC vs. 2024 ACC SCT High

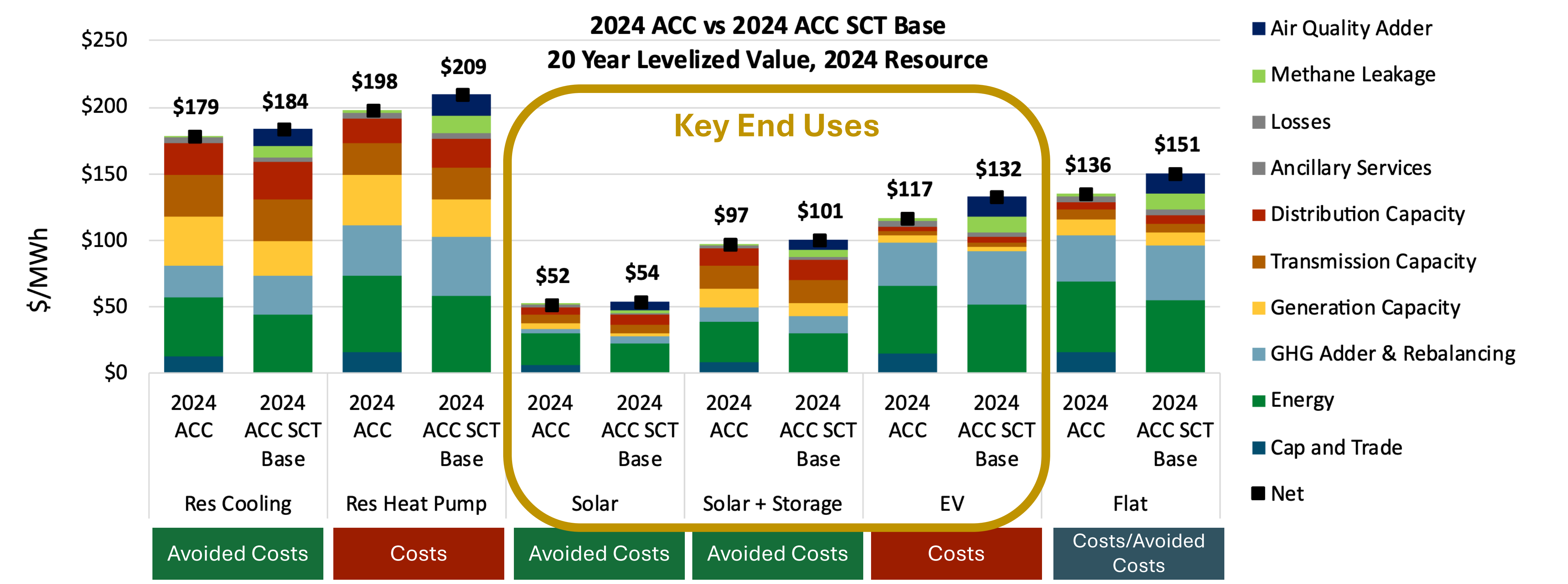
- Higher GHG, Methane Leakage, and Air Quality Adders increase avoided costs and costs
- GHG avoided costs increase while generation capacity avoided costs decrease



Societal Total Avoided Costs by End Use

2024 ACC TRC vs. 2024 ACC SCT Base

+ Higher GHG, Methane Leakage, and Air Quality Adders increase avoided costs and costs
+ GHG avoided costs increase while generation capacity avoided costs decrease



Conclusion and Follow-up

Informal Comments

- Informal comments on the Draft ACC Calculator are due via email by COB August 6th, 2024
  - Send to Alex.Moisa@cpuc.ca.gov, Emily.Pelstring@cpuc.ca.gov, and the R.22-11-013 Service List

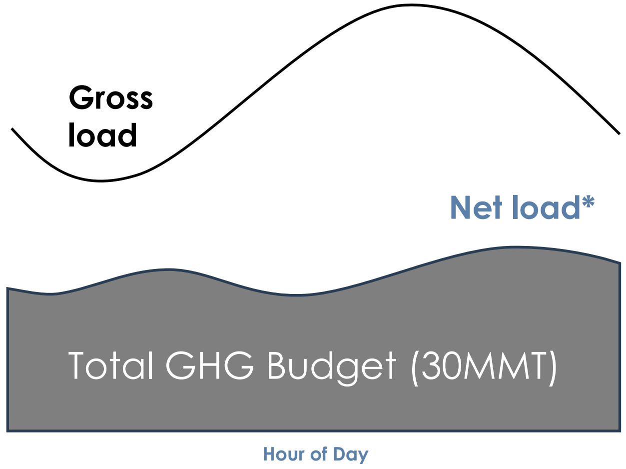
California Public Utilities Commission

Appendix

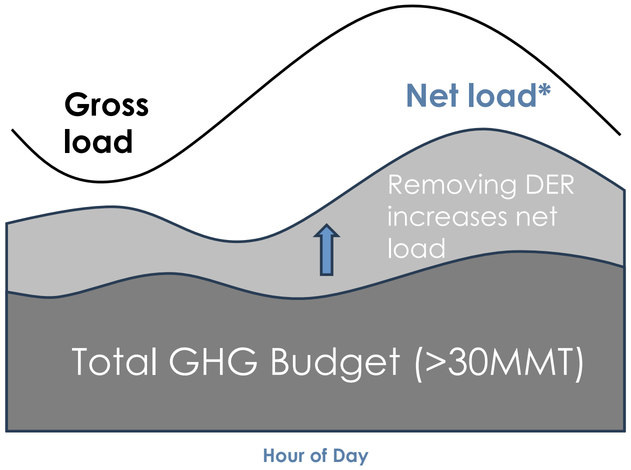
Rebalancing a portfolio with DER removed can increase or decrease marginal costs

- If load reducing DERs are removed from the IRP portfolio, resources will be selected to create a new portfolio and rebalance the system.
- The marginal energy price curve (similar shape as net load) will be different for these two portfolios.
  - While the total revenue requirement will increase, the marginal costs can be higher or lower for the new portfolio and will vary over time.

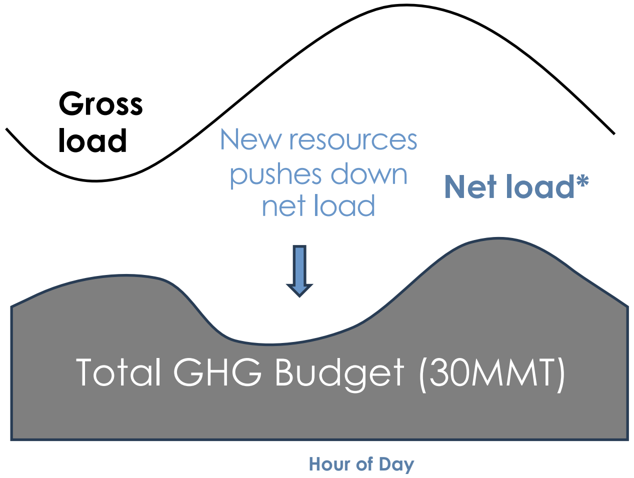
IRP adopted system portfolio has sufficient resources to meet net load



IRP portfolio after removing load reducing DER has higher net load and insufficient resources



New resources are selected to rebalance portfolio. New renewables decrease net load.

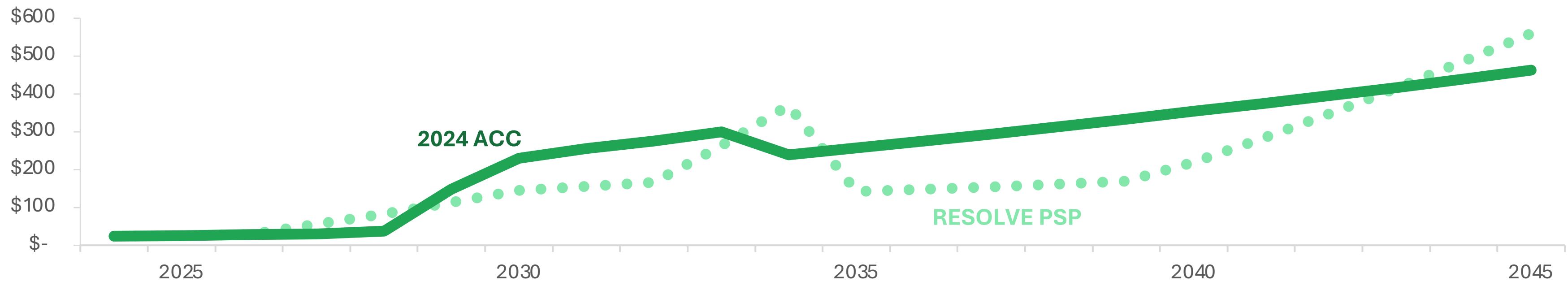


Note: Net load is the gross load minus renewables and BTM generation

Comparison between Avoided Costs and RESOLVE shadow prices

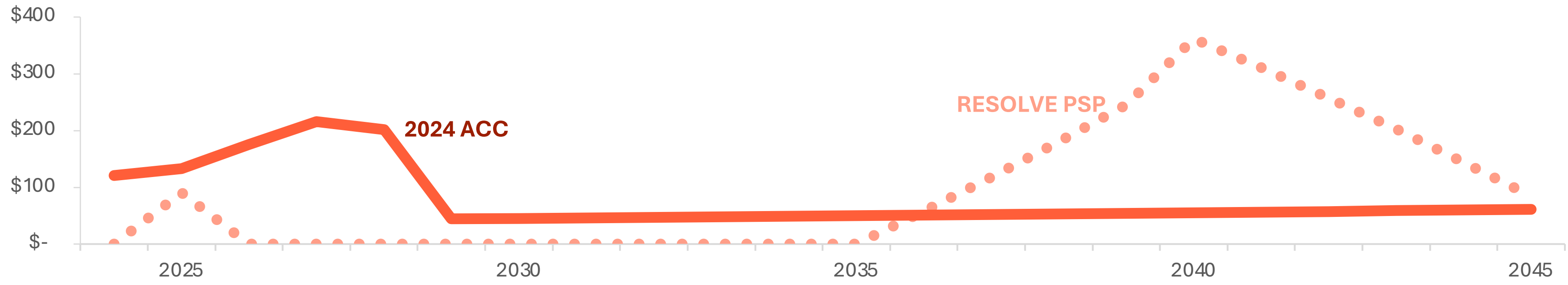
Comparison of Avoided GHG Cost with RESOLVE GHG Value

RESOLVE outputs reflect shadow price on GHG planning constraint plus CARB allowance costs (nominal $/tonne)



Comparison of Avoided Gen Capacity Cost with RESOLVE Capacity Value

RESOLVE outputs reflect shadow price on annual PRM constraint (nominal $/kW-yr)



RESOLVE PRM shadow prices lower than ACC because 1) forced in LSE plans and 2) MTR constraint

Avoided costs track closely with shadow prices

Avoided costs are higher than shadow prices in GHG but lower in capacity, reflecting the inter-dependence of the two values

Note: avoided costs should not be expected to align exactly with shadow prices because:

- PSP forced in specific LSE plans that significantly impacted shadow prices
- Energy prices produced by SERVM are different from RESOLVE

DTIM and LNBA Detailed Calculation Examples

DTIM Calculation of Investment and Load Growth

Real Discount Rate 4.92%

Year	Project Cost ($M) - Systemwide Projects: Pardee Sylmar	New Serrano	Total	SCE Forecast from IEPR: 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

LNBA Calculation – Example Large SCE Project

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**

PCAF Equation for Transmission and Distribution

$$\text{PCAF}[a,h] = \frac{(\text{Load}[a,h] - \text{Threshold}[a])}{\text{Sum of all positive values for } (\text{Load}[a,h] - \text{Threshold}[a])}$$

Where:

- a is the climate zone area
- h is hour of the year
- Load is the net distribution load
- Threshold is the area maximum demand less one standard deviation, or the closest value that results in between 20 and 250 hours with loads above the threshold

Average Hourly End Use Load Shapes