Final 2025 Inputs and Assumptions (I&A) for the 2024-2026 IRP Cycle

Energy Division

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California Public
Utilities Commission

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Introduction

Representation of Filing Requirements and TPP in this Deck

- The 2025 Final Inputs and Assumptions (I&A) document describes the key data elements, assumptions, and methodologies for CPUC IRP analysis and modeling for the 2024-2026 IRP cycle, including both the **2025 LSE Filing Requirements (2025 FR)** and the **2026-27 Transmission Planning Portfolio (26-27 TPP)**
  - The majority of inputs are the same between 2025 FR and 26-27 TPP, but key inputs changed between the two models
- The 2024-26 Inputs & Assumptions were first presented in draft version in February 2025, and modified in response to stakeholder feedback in mid-2025, ahead of 2025 FR modeling
- During 2025 FR modeling, significant shifts in the energy landscape (and additional stakeholder feedback) spurred additional input updates which were implemented for the 26-27 TPP modeling in Fall 2025
  - Primary changes were cost impacts of the OBBBA and updated wind resource potential
- In this document, the "Inputs and Assumptions for the 2025 LSE Filing Requirements" section shows the **full I&A for the 2025 FR, including inputs common with the 26-27 TPP**
- The "Updates to Inputs and Assumptions for the 26-27 TPP" section shows **specific inputs which have changed for the 26-27 TPP**

Summary of RESOLVE Updates Since 25-26 TPP (1)

Further detail can be found in the 2025 Draft Inputs & Assumptions[1]

Data	Change
Zonal Topology (Disaggregation of CAISO)	CAISO RESOLVE zone disaggregated into PG&E, SCE, and SDGE, with associated data updates PG&E<>SCE transmission path expansion candidate(s) added to RESOLVE optimization Remote generator representation added to align with SERVM
Default Candidate Resources	Enhanced Geothermal (EGS) and Generic Long Duration Storage (LDES) added as default candidates Pumped Hydro (PHS) and Adiabatic Compressed Air Storage (A-CAES) combined into a single "Location-Constrained Storage" category
Candidate Regions	Updated to align with CAISO study areas used in transmission planning
Resource Cost	Updated to 2024 NLR ATB New capital cost assumptions for solar, onshore wind, and Li-ion battery New financing costs
Resource Potential	Updates to solar potential using 2024 BLM Western Solar Plan Additional location-constrained storage potential projects included
Minimum Builds	Near-term minimum build constraints added to RESOLVE to reflect recent LSE contracts incremental to the baseline resources (June 2025 IRP Procurement Compliance data)

1 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_draft_inputs_and_assumptions_public_slides.pdf

Summary of RESOLVE Updates Since 25-26 TPP (2)

Data	Change
Baseline Resources	Updated to latest available data from CAISO, WECC, and LSE filings
Planned External (Non-CAISO) Builds	Updated to reflect most recent IRP Procurement Compliance data
Load Forecast & Profiles	Updated to 2024 IEPR Historical baseline profile updated to include 2021 & 2022
Generation Profiles	Updates to wind model used by staff to develop profiles 2021 and 2002 weather years included New hourly profiles for EGS to represent thermal ambient derates
Day Sampling	Updated 36 RESOLVE sample days incorporating latest load and generation profiles
PRM and ELCC Inputs	Updated target PRM % and resource ELCCs informed by SERVM runs 3D solar-storage surface with dimensions for solar, 4-hr battery, and 8-hr battery (multipliers for longer duration storage relative to 8-hr dimension)
GHG Target	Near-term trajectory updated to reflect historical GHG data up to 2022 Long-term trajectory updated to reflect higher CAISO load share for statewide GHG target
Dollar Year	Costs inflated to 2024 dollar year from 2022 dollar year
Inter-Day Sharing	Functionality in RESOLVE to track long duration storage state of charge over a chronological 8760 hours to enable energy sharing over multi-day and/or seasonal periods

Summary of RESOLVE Updates Since 2025 Draft I&A

Data	Change
Resource Regions	Designated candidate wind and geothermal areas in the portion of northeastern CA served by NVE as new Northeast CA region
Resource Potential and Land Use	• Updated to latest available CEC Protected Areas Layer and Core Land-Use Screen, including corrections to the incorporation of the 2024 BLM Western Solar Plan • Incorporated Global Wind Atlas wind speed data into wind resource potential analysis • Clarified treatment of in-state, non-CAISO wind and geothermal potential within IID and NVE service territories • Revised assumptions for estimating the near-field EGS resource potential
Resource Availability	Extended the first available year of Idaho Wind to 2031 due to recent federal policies
Transmission	EGS resources fully modeled on the CAISO transmission system to study locational dependencies
Resource Cost	Incorporated latest federal policy impacts, including July 2025 Budget Reconciliation Bill and tariffs
Gas Retention Costs	Updated to increase over time to the cost of repowering. More information available in the appendix.

Acknowledging Current Uncertainties

- IRP Staff are aware of a number of significant potential policy changes at the federal level that could have impacts on the inputs and assumptions posed in this deck, as well as IRP's modeling.
  - IRP Staff will continue to monitor those developments if and as they materialize and can consider updating the I&A as necessary based on those developments.
  - Additionally, IRP Staff will consider modeling sensitivity scenarios to consider any potential impacts of these uncertainties, if necessary, in developing portfolios that will use this set of inputs and assumptions.

Inputs and Assumptions for the 2025 LSE Filing Requirements (2025 FR)

Updated Zonal Topology

RESOLVE Topology

- RESOLVE models regions under CPUC jurisdiction (CAISO) and neighboring regions
  - Regions within CAISO are the focus of the RESOLVE model, subject to optimized build and dispatch
  - Neighboring external regions (IID, LDWP, NCNC, NW, SW) have optimized dispatch, but no optimized new build in RESOLVE, only existing resources and forecasted future builds
- Starting in this cycle, RESOLVE will disaggregate CAISO into PGE, SCE, and SDGE
  - These zones may be collectively referred to as CAISO throughout this presentation
- Additional BAAs in the western interconnect (WECC) that do not have direct transmission ties to CAISO are excluded in RESOLVE, consistent with SERVM modeling

RESOLVE Zone	Balancing Authorities
PGE	**Pacific Gas & Electric (PGE)**
SCE	**Southern California Edison (SCE)**
SDGE	**San Diego Gas & Electric (SDGE)**
IID	Imperial Irrigation District (IID)
LDWP	Los Angeles Department of Water and Power (LADWP)
NCNC	Balancing Area of Northern California (BANC) Turlock Irrigation District (TID)
NW	Avista (AVA) Bonneville Power Administration (BPAT) Chelan County Public Utility District (CHPD) Douglas County Public Utility District (DOPD) Grant County Public Utility District (GCPD) Pacificorp West (PACW) Portland General Electric (PortlandGE) Puget Sound Energy (PSEI) Seattle City Light (SCL) Tacoma Power (TPWR)
SW	Arizona Public Service (AZPS) Nevada Power (NEVP) Salt River Project (SRP) WAPA – Lower Colorado (WALC)

Motivation for the Disaggregation of CAISO

- The CAISO zone will be disaggregated into PGE, SCE, and SDGE zones in this IRP cycle, requiring updates to several inputs
- Key benefits of disaggregating the CAISO zone include:
  1. Better alignment with SERVM topology
  2. Inter-zonal transmission constraints between the three zones will be factored into the optimization of resource builds and non-retention decisions
  3. Allow the model to evaluate new build decisions related to transmission expansion between the IOU zones

Input Updates Related to Zonal Disaggregation

- Several inputs are now differentiated between the three CAISO IOU zones (PGE, SCE, SDGE), with details shown later in the presentation as needed

Data Type	Updates Associated with Zonal Disaggregation
Baseline Resources Capacity & Profiles	**Disaggregated and assigned to IOU Zones**
Thermal Retention Constraints	**Modeled at IOU level**
Annual Loads & Load Profiles	**Modeled at IOU level**
Candidate Resources Potential & Profiles	**Assigned to IOU Zones**
Transmission Paths	**Transmission path limits between PGE, SCE, and SDGE added**
Policies (Reliability, GHG, Clean Energy)	No change in methodology, modeled at the CAISO level

Baseline (Online and In-Development) Resources

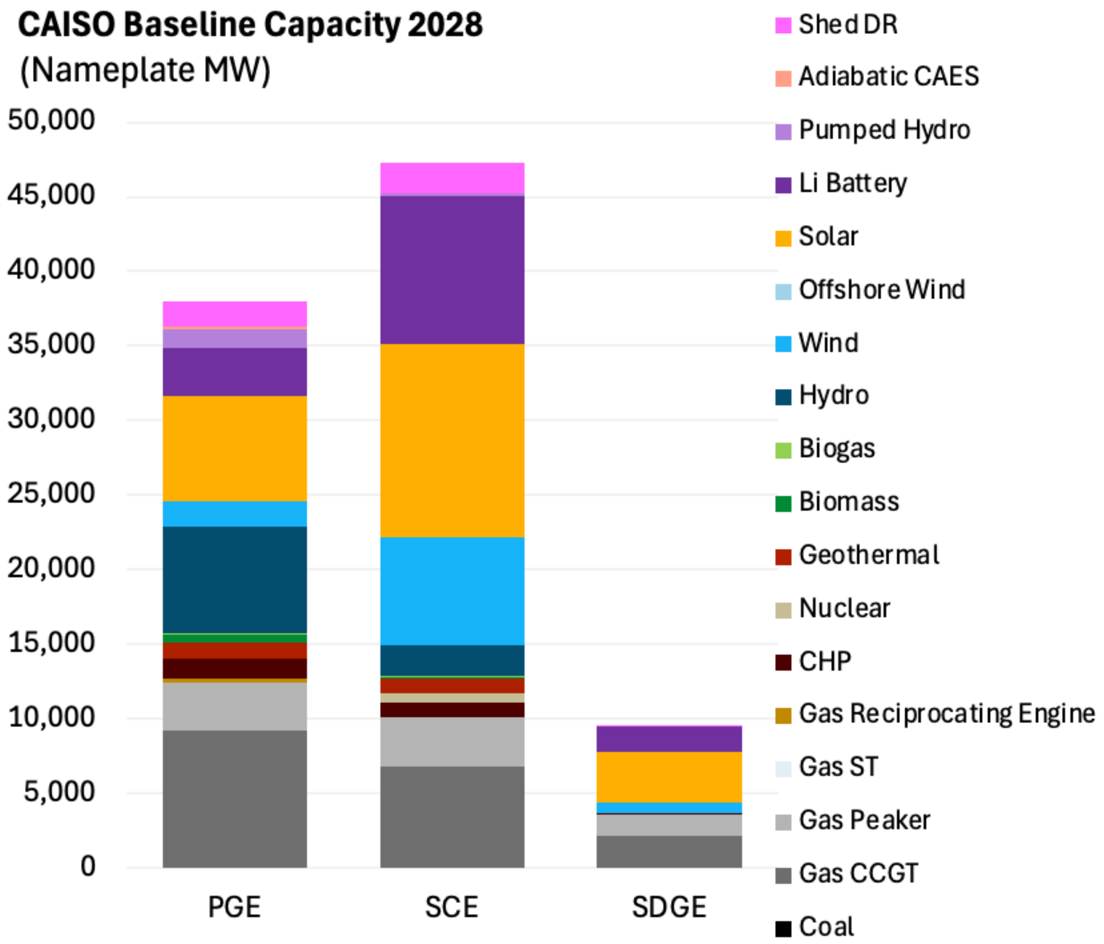
Defining the Baseline

- The resource baseline is an input to both RESOLVE and SERVM, and includes both online and in-development resources for both CAISO and non-CAISO zones
  - **Online**: Units already built and operating, net of scheduled retirements
  - **In-Development**: Units with approved contracts and/or under construction
- The baseline does not include **candidate** resources, which can be selected by RESOLVE as new additions
- The baseline is constructed from multiple sources:
  - Online CAISO: CAISO Master Generating Capability List (MGC)[1] and the CAISO Retirement and Mothball List[2]
  - In-Development CAISO: 12/1/2023 LSE IRP Compliance Filings[3] (excluding generic planned/new)
  - Non-CAISO (external): WECC 2032 Anchor Data Set (ADS)[4]

1 http://oasis.caiso.com/mrioasis/logon.do; 2 https://www.caiso.com/Documents/AnnouncedResourceRetirement-MothballListPosted-051321.html#:~:text=The%20California%20ISO%20has%20posted%20an%20updated%20list,The%20list%20includes%20all%20resources%2C%20regardless%20of%20size.; 3 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/irp12123compliancereport.pdf; 4 https://www.wecc.org/program-areas/reliability-planning-performance-analysis/reliability-modeling/anchor-data-set-ads

CAISO Baseline Capacity: Overview

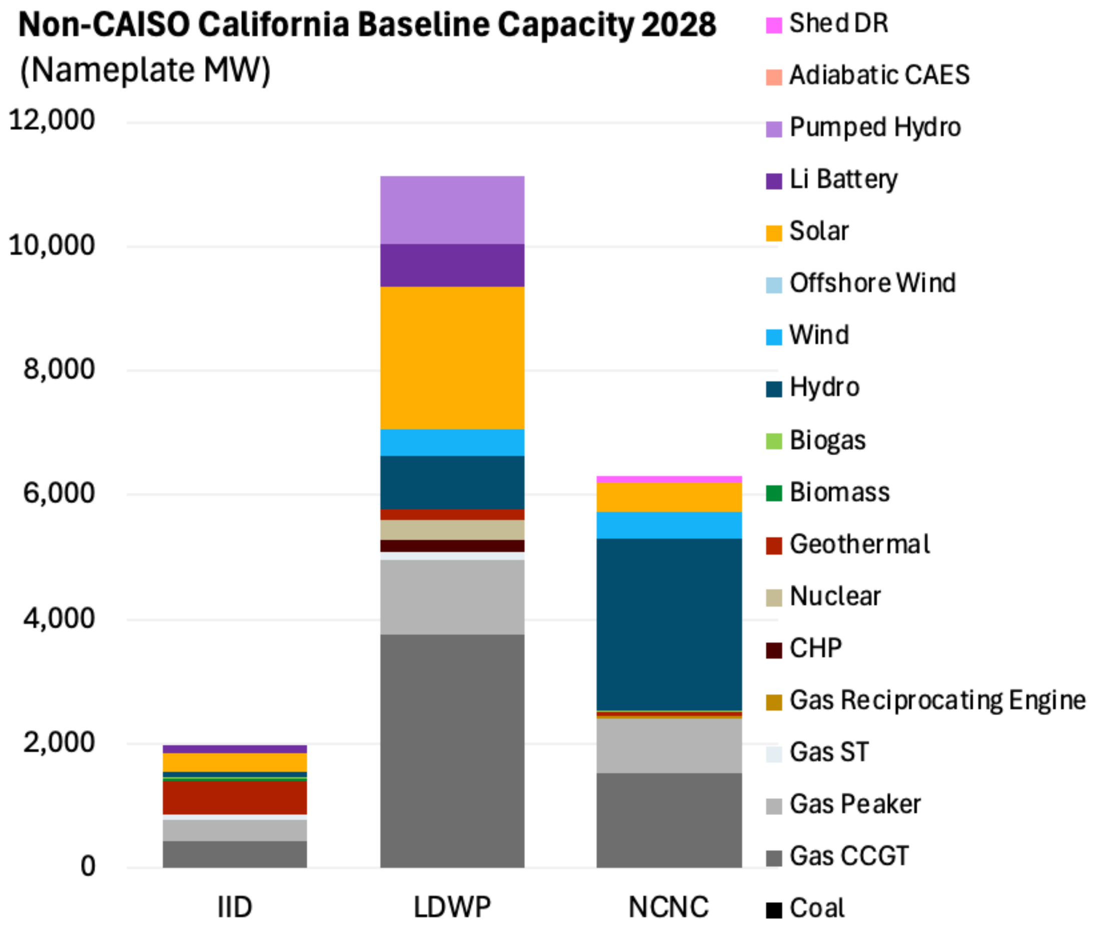
- Data from CAISO Master Generating Capability List (MGC) and 12/1/2023 LSE Filings
- ~95 GW of resources are in the CAISO baseline, including ~13 GW in-development
    - ~29 GW fossil generators
    - ~13 GW clean firm & hydro
    - ~9 GW wind
    - ~23 GW solar
    - ~16 GW storage
    - ~4 GW demand response



CAISO CHP is forced to phaseout from 2031-2040; this is done as a post-processing step to generator list data.

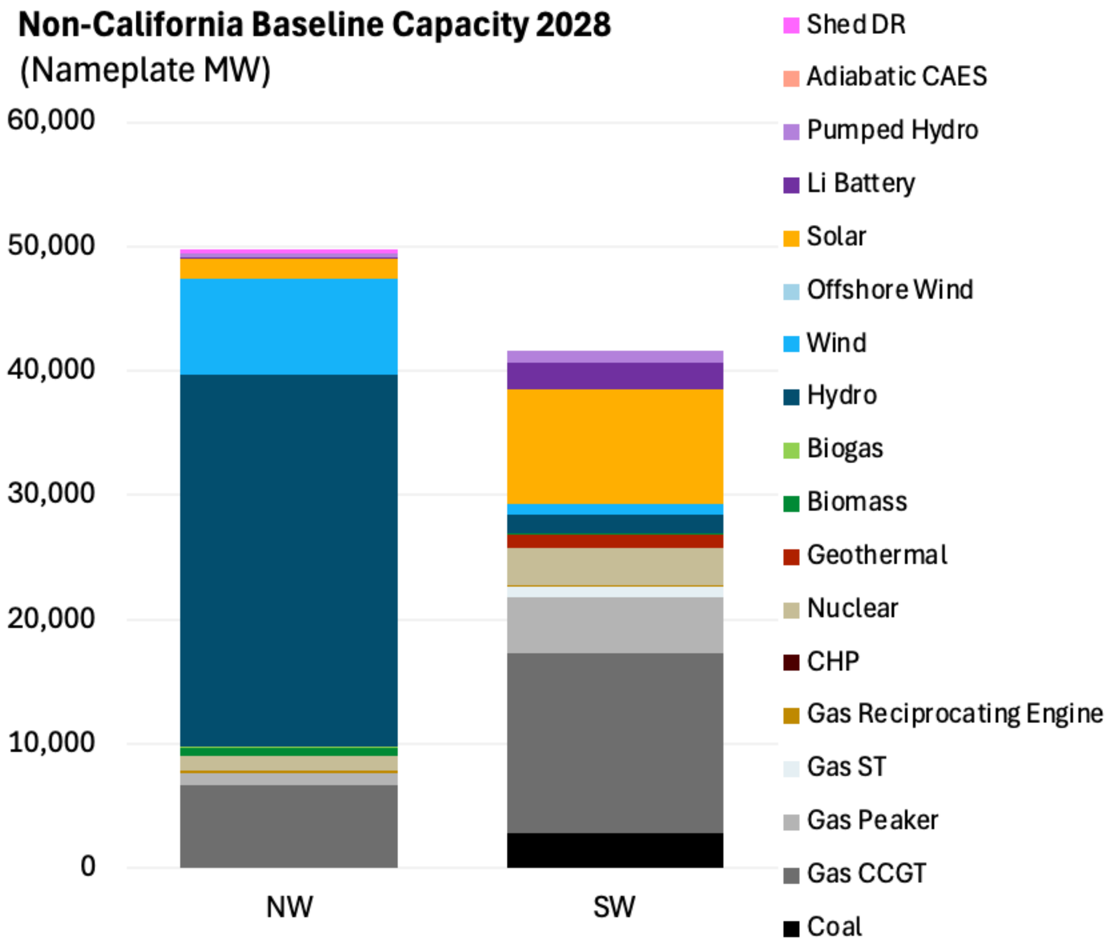
Non-CAISO California Baseline Capacity: Overview

- Data from WECC 2032 Anchor Data Set (ADS)
- A total of ~19 GW capacity is in the non-CAISO California baseline
  - 2.0 GW in IID
  - 11.1 GW in LDWP
  - 6.3 GW in NCNC



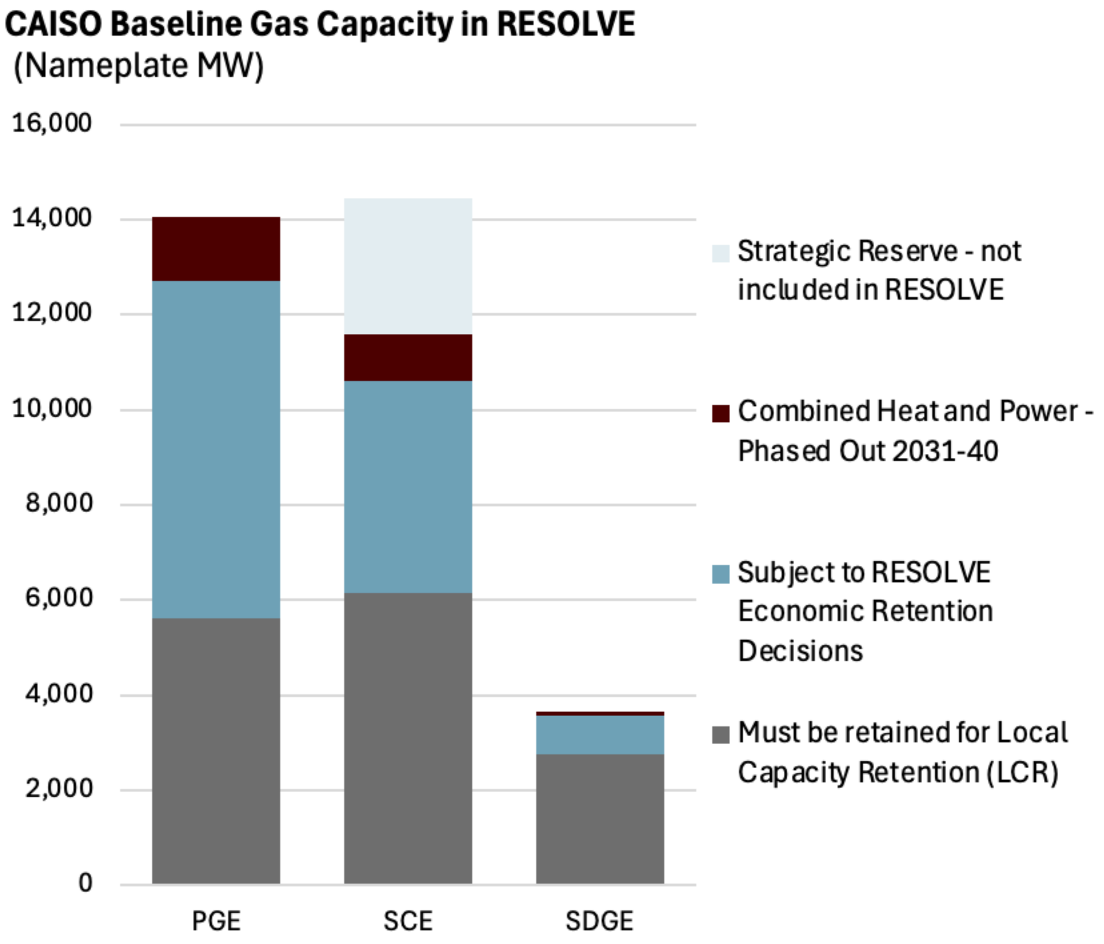
Non-California Baseline Capacity: Overview

- Data from WECC 2032 Anchor Data Set (ADS)
- Regions outside of California included in RESOLVE and SERVM modeling include Oregon and Washington (NW), Arizona and Nevada (SW)
- A total of ~91 GW capacity is in the baseline for modeled zones outside of California
  - 49.7 GW in NW
  - 41.6 GW in SW



Summary: Gas Retention in RESOLVE

- Combined Heat and Power (CHP/Cogen) units in CAISO are assumed to phaseout linearly from 2031 to 2040
- Gas CCGT, Peaker, and Reciprocating Engines in CAISO are subject to economic retention decisions
  - Decision is whether or not to retain on the CAISO system (could serve non-CAISO load)
  - RESOLVE optimizes the amount of gas retained, weighing the fixed O&M cost of gas generators against their contribution to reliability
  - Assume ~14.5 GW of CAISO baseline gas capacity must be retained in RESOLVE to meet local capacity requirements
  - ~12.5 GW is eligible for non-retention (~7.5 GW not in local zones and ~5 GW in local zones is replaceable by 4-hr batteries)
- Three CAISO steam turbines in the Strategic Reserve are not included in modeling



MW totals represent all existing gas in CAISO

RESOLVE Hydro Tranches

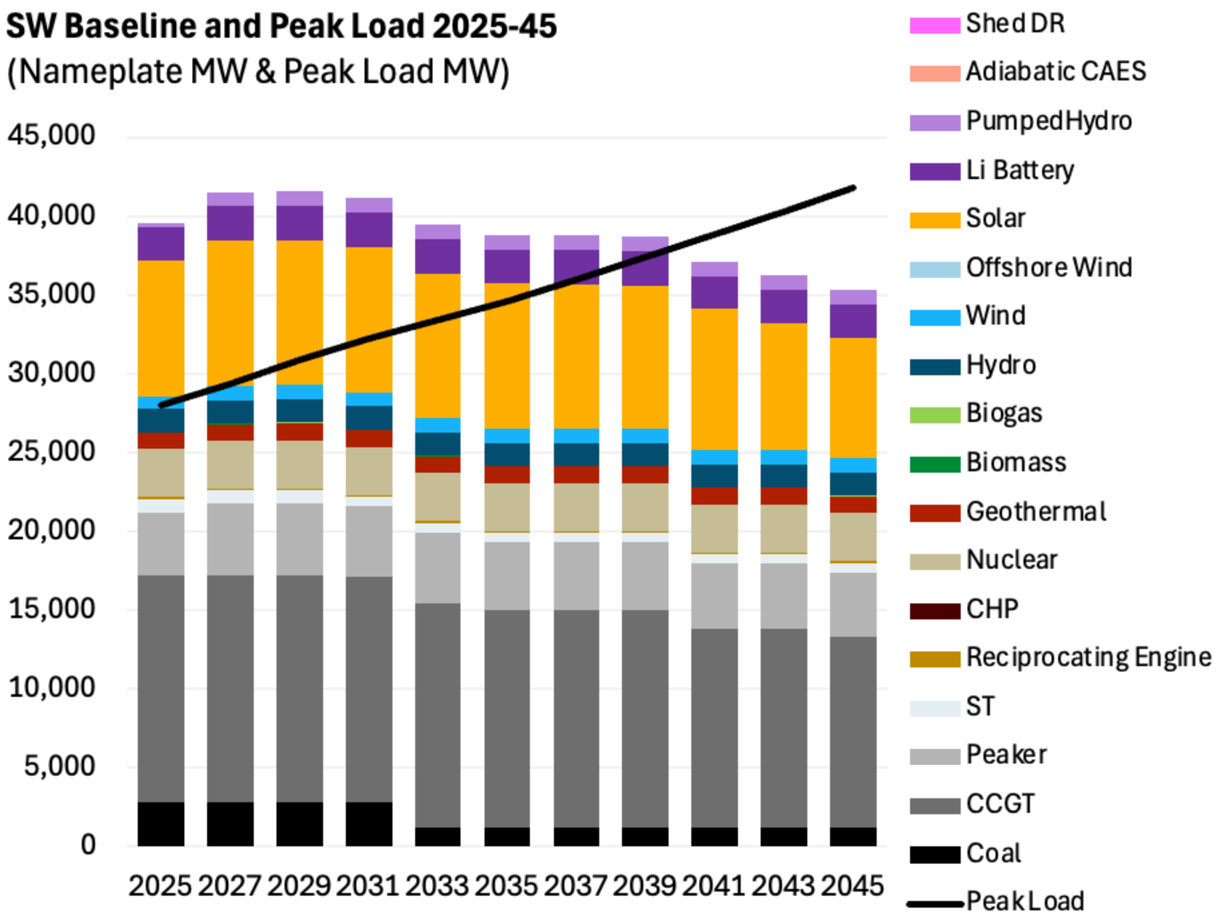
- For CAISO only, Hydro is split into tranches to reflect RPS eligibility and dispatch attributes
- New in this cycle, a total of four Hydro tranches reflect a combination of two delineations:
  - **Small** (<30 MW) and **large** hydro for RPS accounting
  - **Run-of-river** and **non-run-of-river** for dispatch profiles
- Additionally, firm hydro imports from the Northwest (**NW_Hydro_for_CAISO**) are modeled as GHG-free imports
  - 8.31% of NW Hydro generation is designated as NW_Hydro_for_CAISO, based on historical asset controller import data from CARB

CAISO Hydro Tranche	GHG-free Energy	RPS Eligible	CAISO RA Contribution	Dispatch Profile
Small, run-of-river	Yes	Yes	Yes	Run-of-River
Small, non-run-of-river (scheduled)	Yes	Yes	Yes	Non-Run-of-River
Large, run-of-river	Yes	No	Yes	Run-of-River
Large, non-run-of-river (scheduled)	Yes	No	Yes	Non-Run-of-River
NW_Hydro_for_CAISO	Yes	No	No	Non-Run-of-River (NW profile)

Forecasted External Loads and Resources

Forecasting Future External Zone Builds: Motivation

- Baseline (online and in-development) resources are input into RESOLVE for all zones (CAISO and external)
- RESOLVE optimally selects new builds for CAISO, but not for external zones
- Due to load growth in the external zones, the baseline will eventually fail to meet these zones' reliability and energy needs, requiring RESOLVE to build resources in CAISO for export to these zones (an unrealistic outcome)
- To ensure external zones have a realistic future portfolio to meet their needs, forecasted future builds are input into RESOLVE, based on recent IRP plans



Graph is intended as an illustrative example of future external zone needs and is not a forecast for load and resource balance.

Forecasting Future External Zone Builds: Steps

Balancing Areas with IRP Reports

1. Collect load forecast data from the balancing area's IRP report
2. Collect data for future builds (starting in 2024) by resource type from the IRP report
3. If the IRP horizon does not extend out to 2045, extrapolate the builds to meet peak load growth
4. Subtract out any baseline in-development (online 2024 or later) capacity from the builds to prevent double counting

Balancing Areas without IRP Reports*

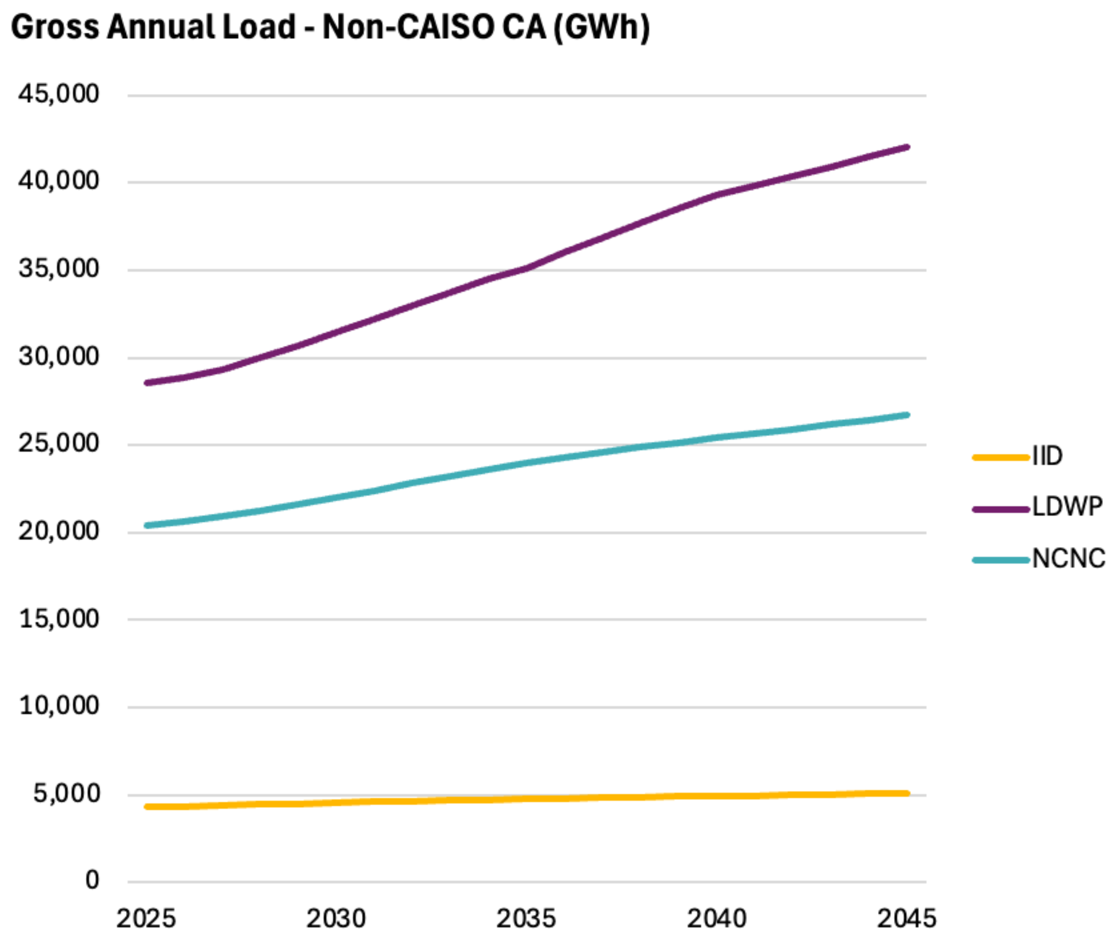
1. Collect load forecast data for the balancing area from FERC Form 714
2. Use the forecast resource mix from neighboring balancing areas as an estimated portfolio
3. Scale the portfolio up or down to meet the balancing area's peak load
4. Subtract out any baseline in-development (online 2024 or later) capacity from the builds to prevent double counting

5. **Add the future build portfolio on top of the baseline**

*The majority of POUs modeled outside of California do not conduct regular IRPs

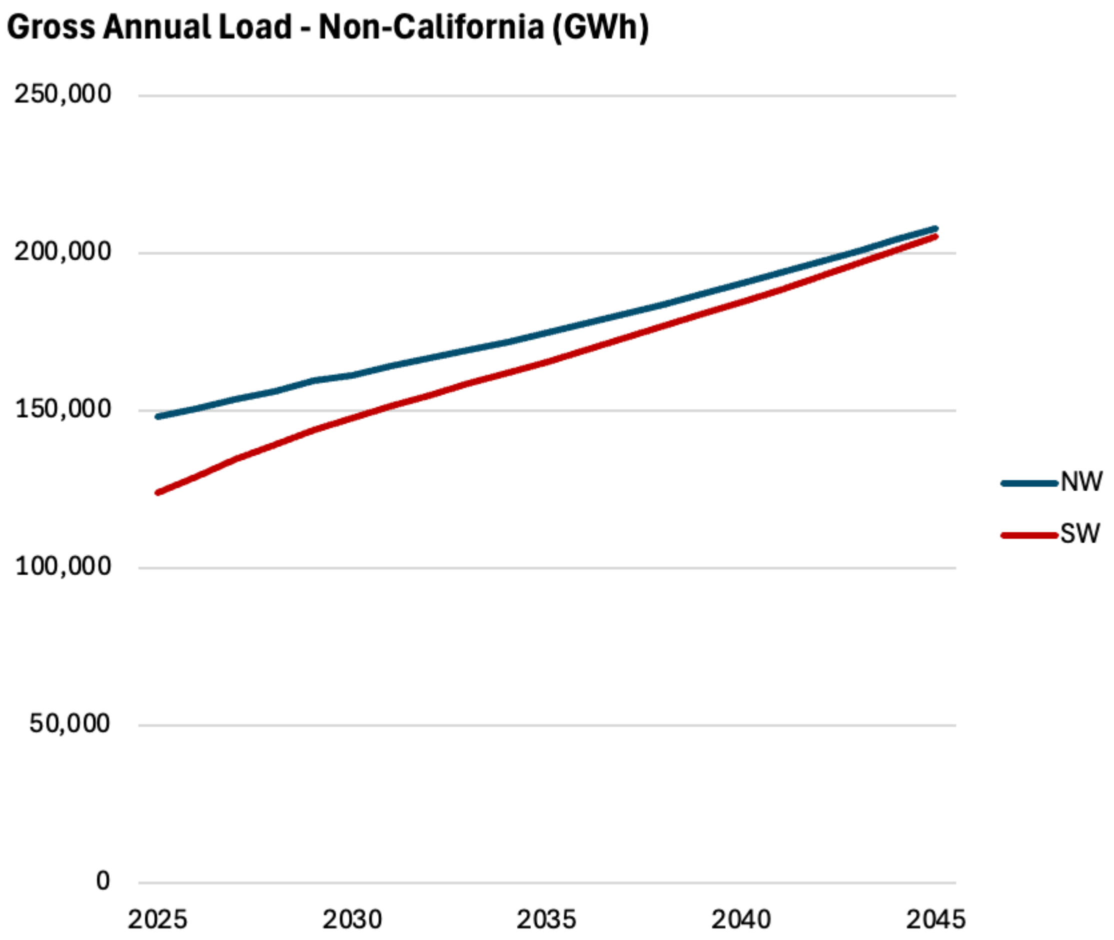
External Zone Gross Loads (Non-CAISO CA)

- Load forecasts for non-CAISO California zones use data from the latest CEC IEPR forecast, extrapolated to 2050
  - Gross load is calculated by taking the IEPR managed load, plus IEPR BTM PV impact



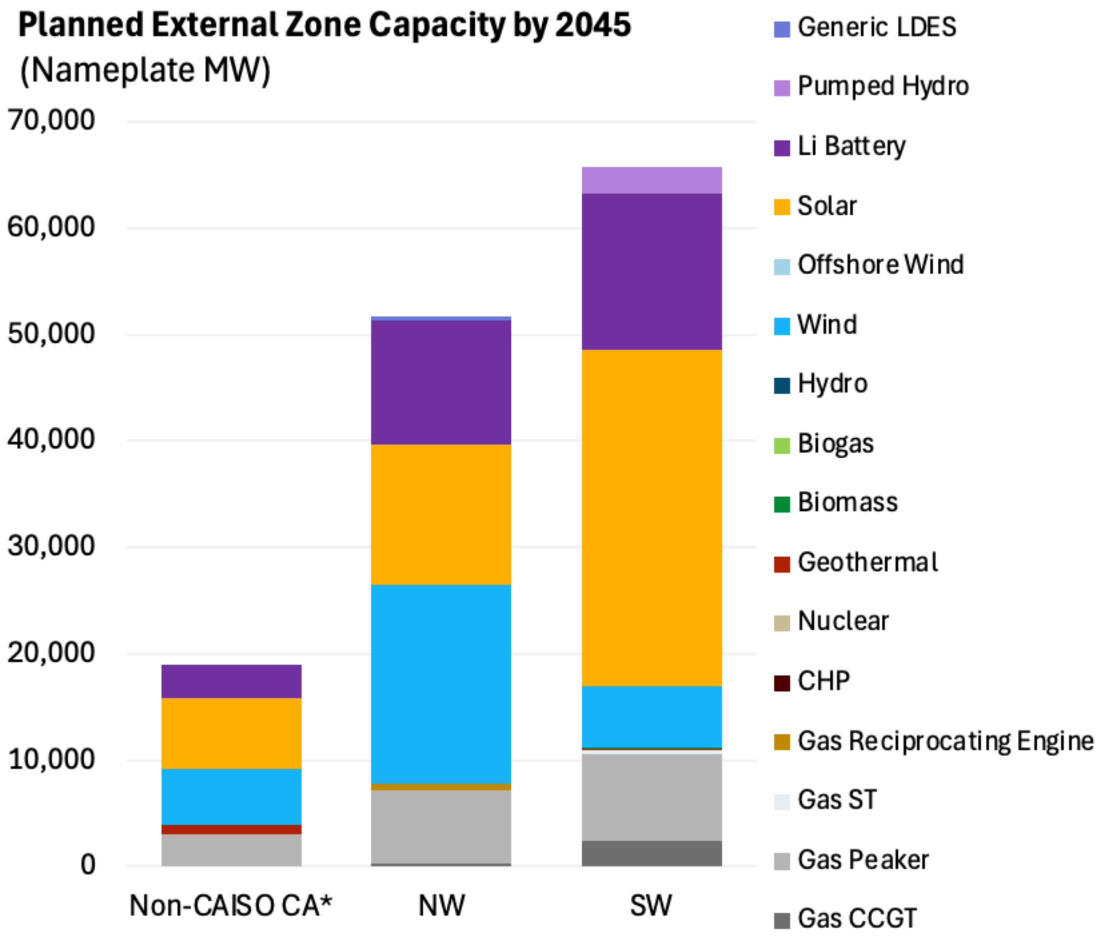
External Zone Gross Loads (Non-CA)

- Load forecasts for zones outside of California were derived using managed load forecasts from IRP reports or FERC Form 714, with BTM PV generation added back to calculate gross load
  - External BTM Solar is forecasted by extrapolating the historical (2019-2023) growth sourced from EIA-861M



Summary of Forecasted External Resources

- Across external zones, forecasted builds increase steadily over the modeling horizon and include a mix of wind, solar, storage, and firm resources
- Planned builds by RESOLVE zone and year are shown in the I&A report



*Sum of IID, LDWP, and NCNC

Summary of Candidate Resources

Summary of Updates to Candidate Resources

- Key updates for the 2025 I&A:
  - Refreshed resource costs, including updating to NLR 2024 ATB, preparing new capital cost assumptions for solar, onshore wind, and Li-ion batteries, and developing new financing costs for all technologies
  - New regions used to represent in-state resources, aligning with the study areas used by CAISO in the TPP analysis
  - Updates to the solar resource potentials using the 2024 BLM Western Solar Plan and updates to onshore, in-state wind potentials using the latest wind capacity factor data from NLR
  - New resource potential estimates for enhanced geothermal (EGS) and location-constrained long duration energy storage (LDES) (12-hr)
  - Updated CAISO transmission deliverability constraint estimates
  - New interconnection constraints to reflect locational interconnection limitations

Optimized Resources in RESOLVE

- **Optimized resources** are represented as decision variables in the RESOLVE optimization and include the following sub-categories:
  - Default Technologies (included in all cases): established, commercially viable technologies
    - *Existing:* Solar, wind, geothermal (conventional and enhanced), Li-ion batteries, location-constrained long duration energy storage (12-hr), shed demand response, and candidate thermal resources
    - *New in this IRP cycle:* Enhanced geothermal (including other next-generation geothermal technologies) and generic long duration energy storage (12-, 24-, and 100-hr)
  - Non-Default technologies (e.g. emerging technologies) have not been updated for filing requirements modeling but could be updated ahead of the next Preferred System Plan (PSP)
- **Non-optimized resources** are also modeled in RESOLVE, but have prescribed adoption over time based on the IEPR load forecast, and are not represented as decision variables in the optimization
  - Customer PV
  - BTM Li-ion battery storage
  - Energy efficiency

Candidate Resource Costs

Summary of Resource Cost Updates

- Primary data source for most conventional and emerging technologies have been updated to **NLR 2024 ATB and PNNL Energy Storage Grand Challenge**
- New CAPEX assumptions for the 2025 I&A have been developed for utility-scale solar, onshore wind, and Li-ion batteries
  - Current-year solar, wind, and Li-ion battery CAPEX have been benchmarked to recent market reports, establishing a new 2023 base cost with low/high cost spread
  - Custom trajectories of CAPEX in future years account for greater variability, reflecting uncertainty in future conditions and graduating cost declines over time
- Market-derived financing assumptions are now used to calculate key cost metrics (LFC, LCOE)
  - Cost of Debt, Cost of Equity, and WACC
- State-specific cost multipliers for CAPEX, FO&M, and Interconnection (IX) have been refreshed using latest labor, site control, and spur line length estimates

Tax Credit Schedules under Recent Federal Policies

- Utility-scale solar and onshore wind resources are assumed to receive the PTC
- Other zero-carbon technologies, including distributed solar, offshore wind, geothermal, biomass, and storage resources, are assumed to receive the ITC
- All resources receive "Bonus" tax credits (30% ITC, $30/MWh PTC), which assumes that projects meet prevailing wage and apprenticeship requirements
  - Additional adders for domestic content requirements and energy community siting are not modeled
- Credits are assumed to be monetized at 90% of their value
- Under the One Big Beautiful Bill Act (OBBBA), tax credits for variable renewable energy technologies (solar, wind) are scheduled to expire by July 4, 2026, with a safe harbor window extending through 2030

Technology	Inflation Reduction Act (IRA)		OBBBA	
	Final Eligible Year	Safe Harbor Period[1]	Final Eligible Year	Safe Harbor Period[1]
Solar	2045+	4 Years	2026	4 Years
Wind	2045+	4 Years	2026	4 Years
Batteries	2045+	4 Years	2035*	4 Years
Geothermal	2045+	4 Years	2035*	4 Years
Offshore Wind	2045+	4 Years	2026	4 Years
Other Zero-Carbon	2045+	4 Years	2035*	4 Years

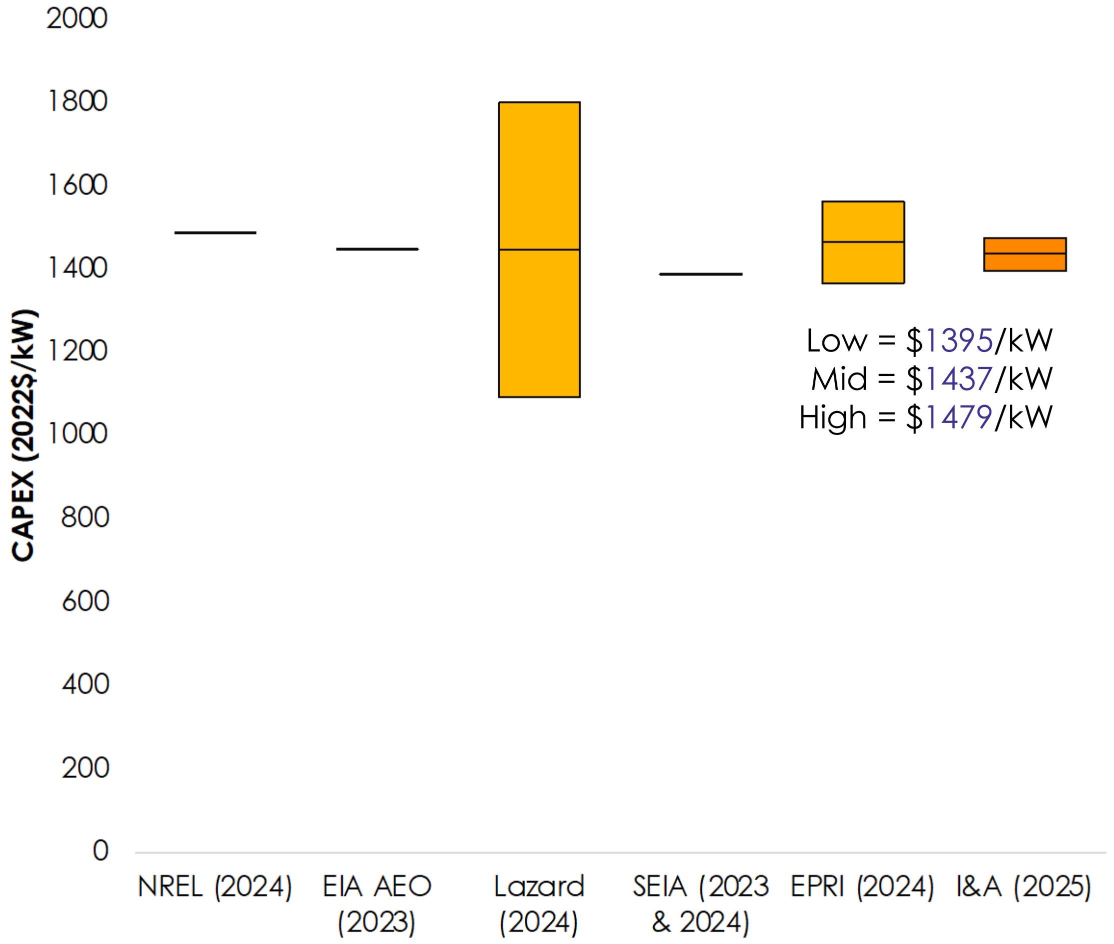
[1] Safe harbor period for most technologies is assumed; under OBBBA, safe harbor of 4 years has been confirmed for solar and wind projects that begin construction by July 4, 2026.

* Final year of full eligibility is 2032, with a three-year phase out (100%/75%/50%) over 2033-2035; with safe harbor, first COD year without tax credits is assumed to be 2040

Current-Year CAPEX Estimation for Select Technologies

- Staff proposes adopting new initial-year (2023) CAPEX values for utility-scale solar, onshore wind, and Li-ion batteries
- Estimates were calculated by averaging values from public reports, including NLR ATB, EIA AEO, Lazard, EPRI, SEIA, DOE, and PNNL
- **Additional materials on resource cost updates are available in the Appendices and in the 2025 I&A Document**

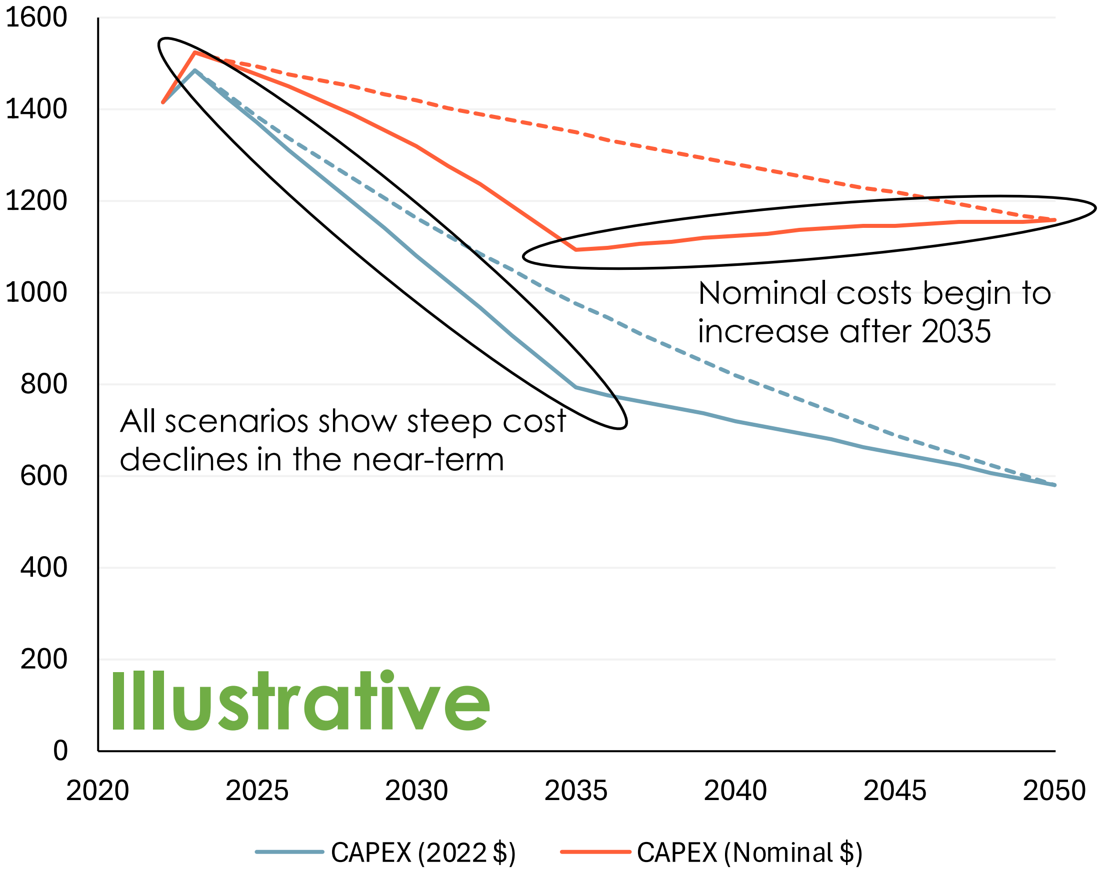
Utility-Scale Solar PV CAPEX Benchmarking



Updated CAPEX Trajectories for Select Technologies

- Staff recommends new CAPEX trajectories for utility-scale solar, onshore wind, and Li-ion batteries
  - "Low" and "High" trajectories informed by NLR 2024 ATB and/or other practical bounds on cost maturation
  - "Mid" as average between Low/High
- New trajectories address two key observations:
  - Solar (shown at right): Removed the discontinuity in nominal costs in 2035
  - Wind/Batteries: A larger variance in reported wind costs is now reflected in the Low and High trajectories

CAPEX for Utility Solar, NLR 2024 ATB Mid



Market-Based Financing Assumptions

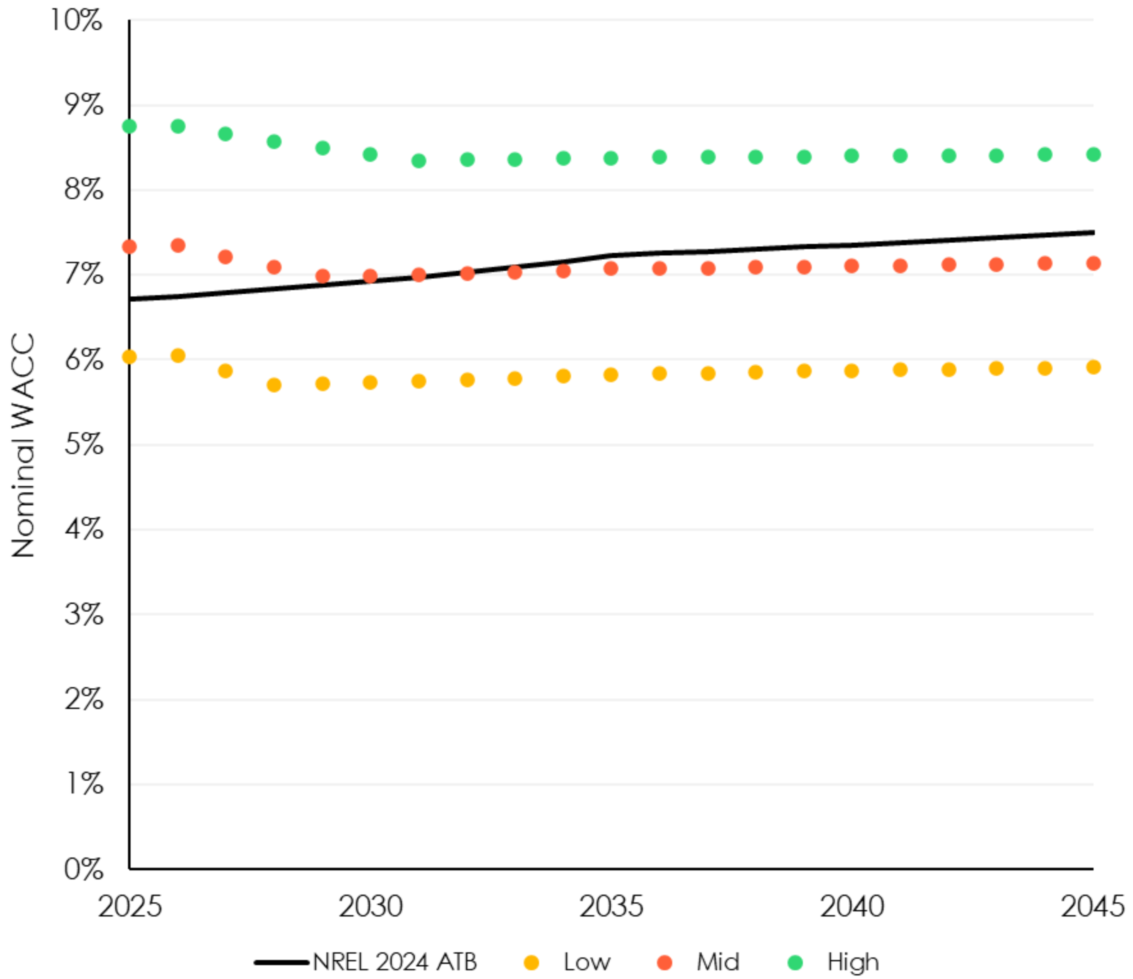
- New for this IRP cycle, staff developed financing assumptions (Cost of Debt, Cost of Equity, Debt Fraction, WACC) to replace NLR ATB for levelization of resource costs:
    1. Market-based indicators align with real projects
    2. Data sources are public, accessible, and authoritative (e.g. U.S. Treasury, Federal Reserve)
    3. Interim updates to cost of capital assumptions can be implemented as often as appropriate
- Market data is used to calculate current and projected future corporate borrowing rates, project leverages, and costs of equity
- Resources are categorized into Risk Classes (Low-, Mid-, and High-Risk) based on perceived financing risk; three WACC forecasts are developed for each Class, corresponding to the Low/Mid/High resource cost scenarios

Technology Risk Classes and WACC Results

Risk Classes for Select Technologies

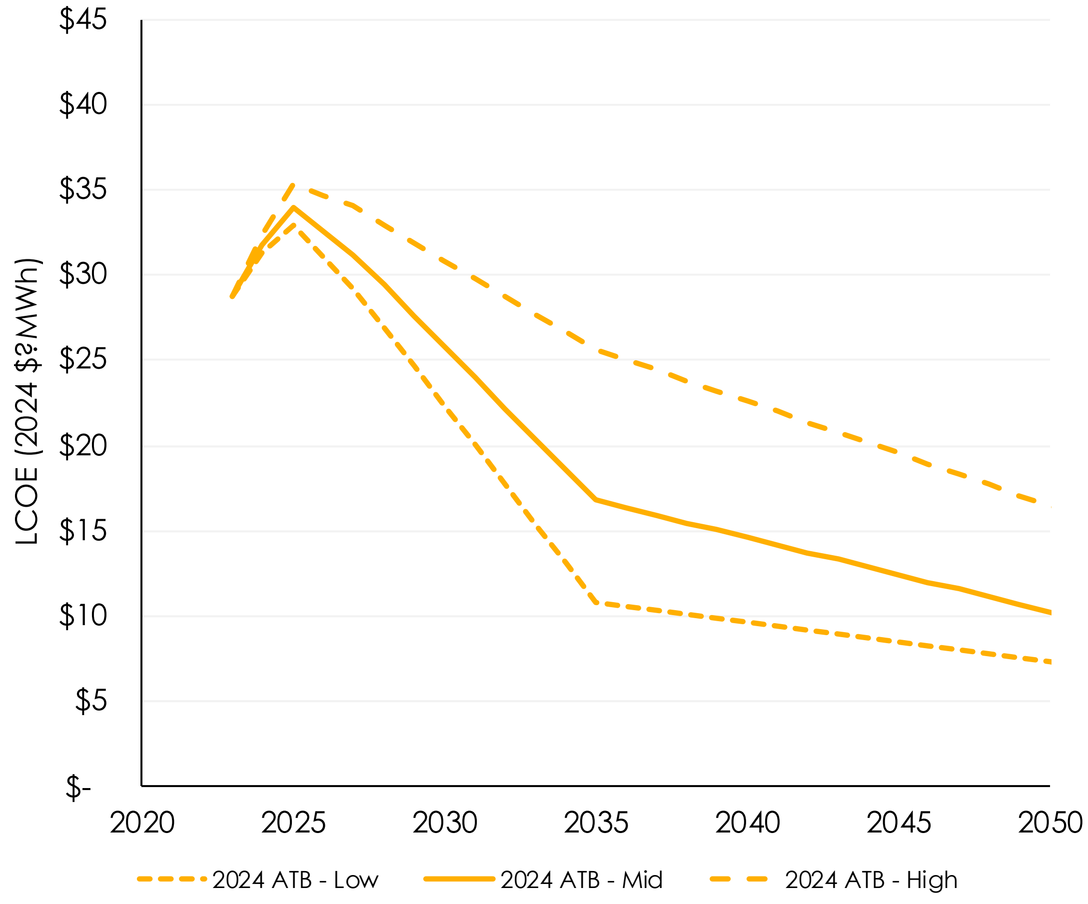
Technology	Type	Risk Class
Wind	Onshore	Low-Risk
Wind	Offshore	High-Risk
Solar	Utility PV	Low-Risk
Geothermal	Hydro – Binary	Mid-Risk
Gas	CT – Frame	Low-Risk
Gas	CCGT	Low-Risk
Biopower	Dedicated	Mid-Risk
Li-ion Battery	Utility Standalone	Low-Risk
LDES	Location-Constrained	Mid-Risk
LDES	Generic	High-Risk

Nominal WACC Scenarios for Low-Risk Technologies

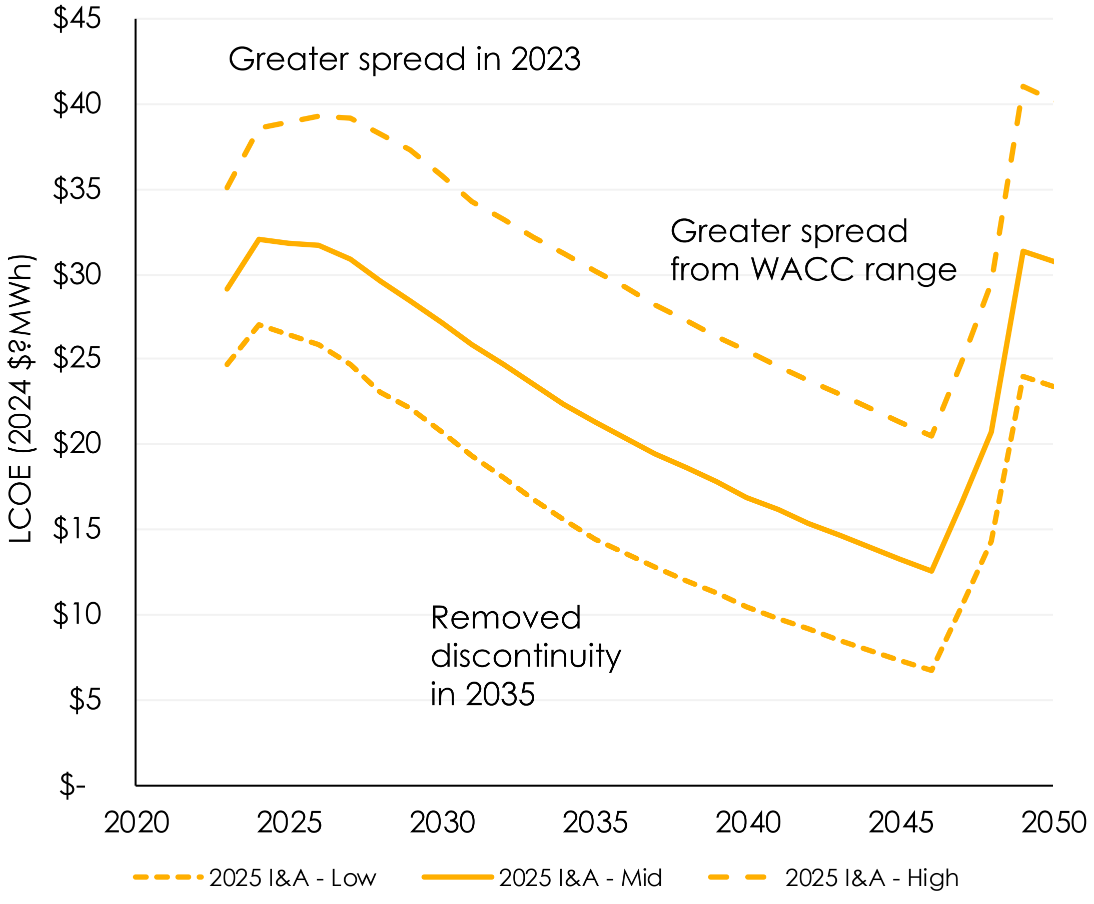


Net Impact of Resource Cost Modifications

NLR 2024 ATB – Utility Solar (33%)[1]



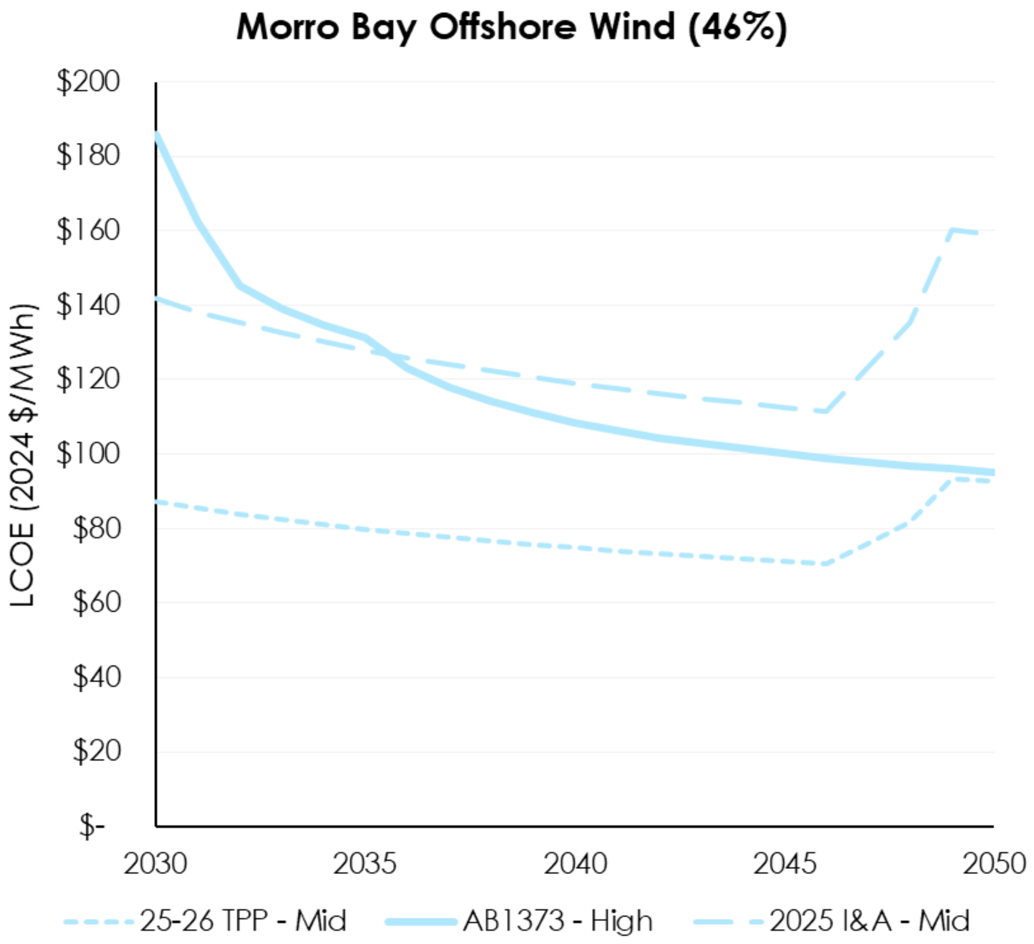
2025 I&A - Utility Solar (33%)



[1] *Reproduced using RECOST*

Offshore Wind Resource Costs

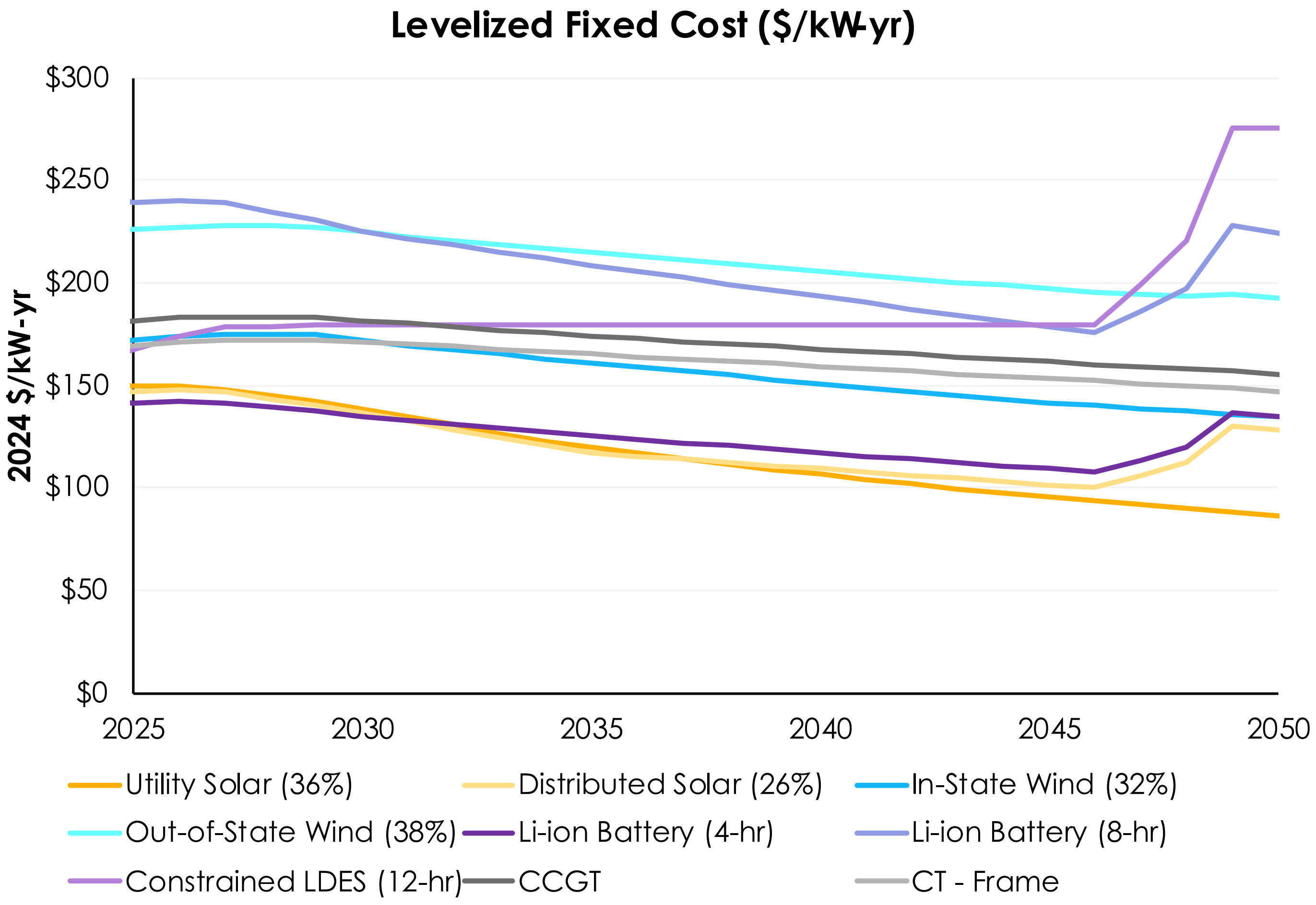
- As part of the AB 1373 Need Determination Analysis published in April 2024, Staff presented a conservative cost scenario for floating offshore wind that applied the NLR 2023 ATB cost trajectory to pilot project costs ($10,000/kW)[1]
- NLR 2024 ATB has adopted a similar approach to their resource trajectories for offshore wind
- Consequently, Staff recommends that NLR 2024 ATB be used for floating offshore wind costs for future modeling efforts



[1] AB1373 Analysis, High Bookend, from Need Determination Analysis for Centralized Procurement of Specified LLT Resources, Slide 17

Summary of Total Levelized Fixed Costs

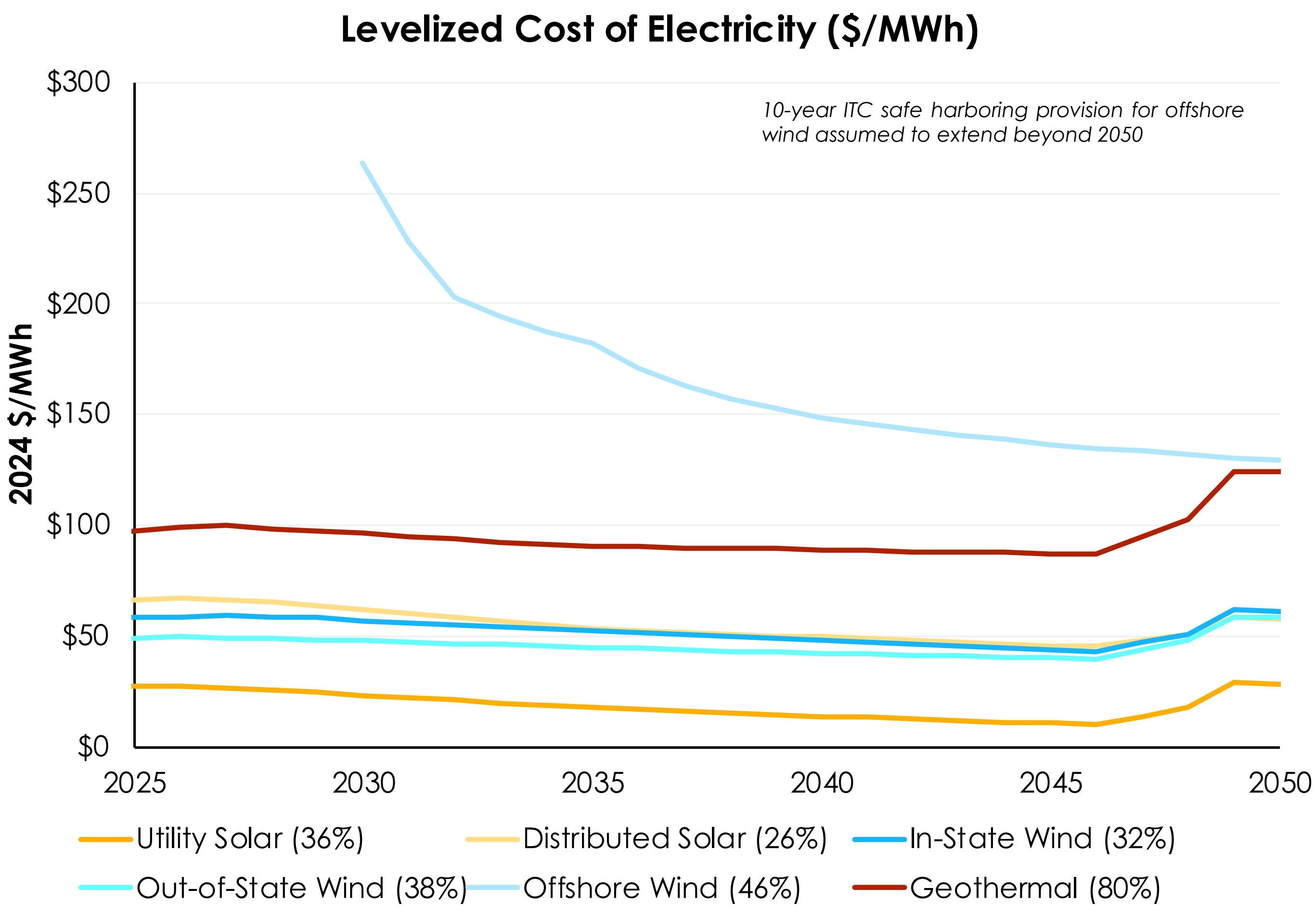
- Total levelized fixed costs (LFC) represent the cost to construct new candidate resources and drive build decisions in RESOLVE
  - Includes overnight capital cost, construction financing costs, fixed O&M, interconnection, and the ITC, where applicable
- Variable costs, including VO&M, fuel costs, **and the PTC for utility-scale onshore wind and solar**, are not included in LFC



Resource Costs

Summary of Total Levelized Cost of Electricity

- LCOE data is indicative only and does not get used in RESOLVE
- The capacity factors reported here are representative of specific candidate resources for each technology type
- IRA tax credits are assumed to continue through the late 2040s, sunsetting by 2049
- Results for out-of-state wind include transmission costs to deliver the resource to the CAISO system



Note: LCOE is not used as an input in IRP modeling and is reported as reference only.

Long-Duration Energy Storage Resources

- Long duration energy storage (LDES) is reported as two distinct resource categories:
  - **Location-constrained LDES**, a single 12-hr duration resource representing pumped hydro and adiabatic compressed air energy systems (A-CAES)
  - **Generic LDES**, three resources representing location- and technology-agnostic storage options at 12-, 24-, and 100-hr durations
- Location-constrained LDES uses the "One New Reservoir" Technology Class 3 costs from NLR 2024 ATB
- Staff has developed new cost assumptions for Generic LDES under two resource cost scenarios:
  - (1) "Mid" costs, taken as an **average** of cost data from **multiple representative technologies**, accounts for **deep uncertainty** in future LDES technologies and costs
  - (2) "LDES Breakthrough" costs assumes a **single representative technology**, identified as the most cost-competitive option within each duration class, achieves a **near-term cost breakthrough** (i.e. "Low" cost)
- Both LDES cost scenarios were developed in accordance with the guiding principles established in the draft I&A:
  - LDES costs should increase with duration
  - LDES round trip efficiency (RTE) should decrease with duration
  - Technologies chosen should not have significant project siting constraints
  - Technologies chosen should be feasible at the given duration

Technologies Considered in Generic LDES Scenarios

- Other technologies from PNNL were excluded due to prohibitive cost or having significant project siting constraints

	Averaged for "Mid" Scenario			
Technology	**Vanadium Flow[1]**	**Thermal[1]**	**Iron-Air[2]**	**Representative Technology ("LDES Breakthrough" Scenario")**
12-hr	✓	✓	✗	Vanadium Flow
24-hr	✓	✓	✓	Thermal
100-hr	✗	✓	✓	Iron-Air

[1] *Thermal and Vanadium Flow costs are taken from PNNL Energy Storage Grand Challenge Cost and Performance Database, 100-MW configurations, https://www.pnnl.gov/projects/esgc-cost-performance*

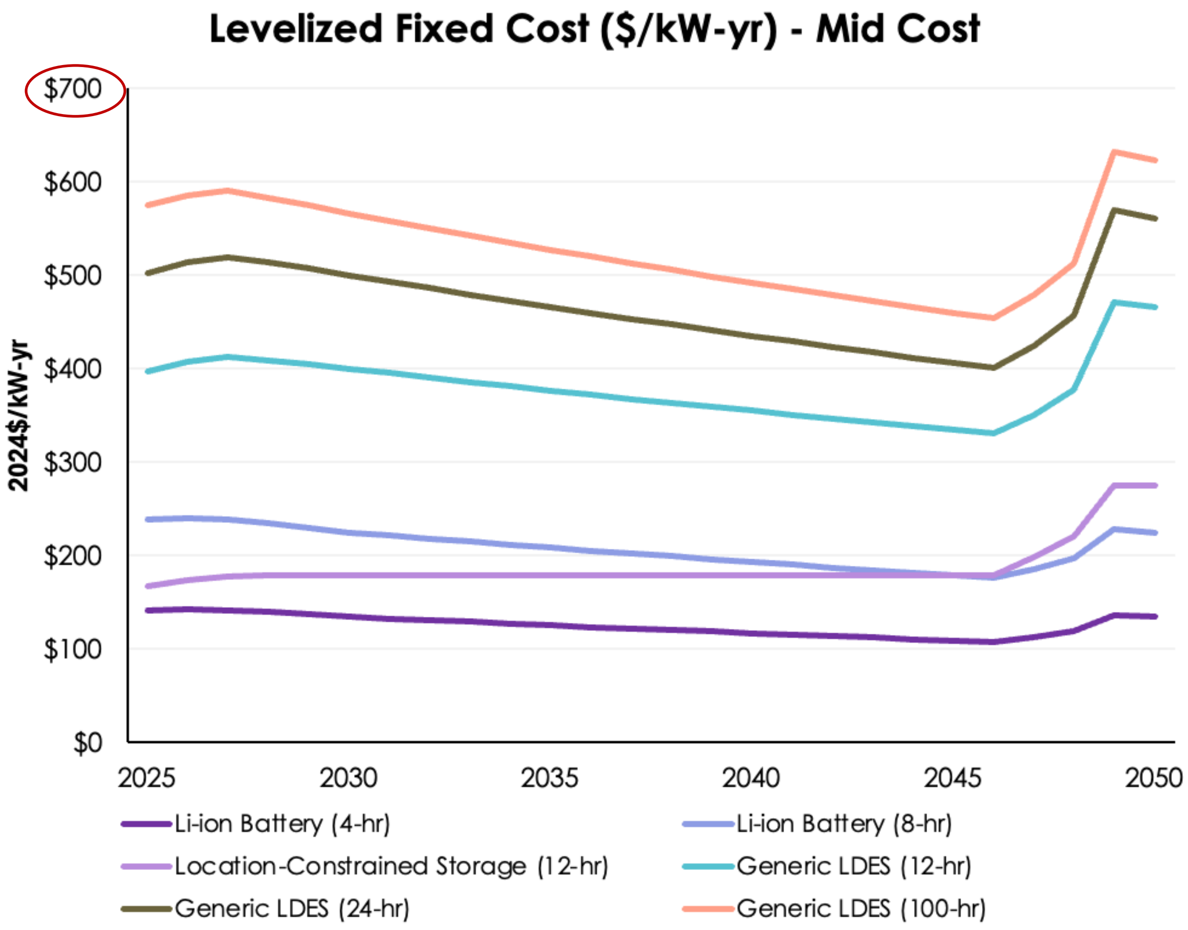
2 Iron-Air costs are taken as an average between: Net-Zero Power: Long Duration Energy Storage for a Renewable Grid, McKinsey, 2021; and Levi, P. et. al. Modeling Multi-Day Energy Storage in New York, Form Energy, 2023.

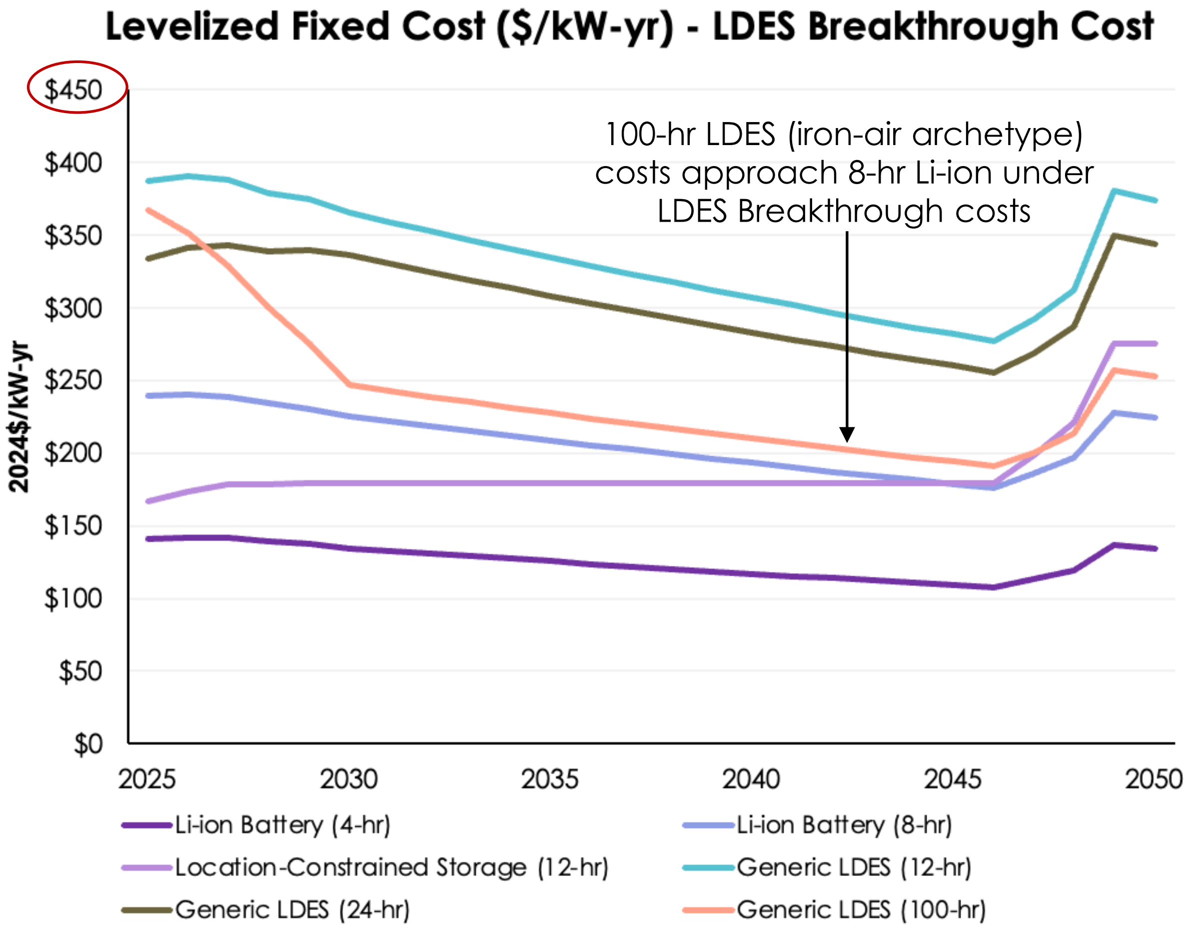
Long-Duration Energy Storage Cost Methodology

- "Mid" Cost Scenario:
  - 2023 and 2030 values taken directly from reported literature[1,2] and averaged, with linear interpolation in intermediate years
  - 2050 value set by taking the average between (1) no cost reduction beyond 2030 (0% learning rate), and (2) the learning rate from 2023-2030
- "LDES Breakthrough" Cost Scenario:
  - Near-term costs are taken from public data sources, both academia and industry:
    - 12-hr: PNNL[1] Vanadium Flow "Low" cost projection for 2023 and 2030
    - 24-hr: PNNL[1] Thermal "Point" cost projection for 2023 and 2030
      - PNNL notes that their "Low" costs are a combination of technologies that results in an "unachievable" cost point, "Point" represents an intermediate cost between "Low" and "Average"
    - 100-hr: LDES Council and Form Whitepapers[2] for Iron-Air battery
      - 2025: LDES Council reported value
      - 2030: Form Whitepaper "Low" reported value
  - All costs are extrapolated to 2050 using a 2% learning rate
    - For comparison, assumed Li-ion learning rate is 1.6%

[1] Thermal and Vanadium Flow costs are taken from PNNL Energy Storage Grand Challenge Cost and Performance Database, 100-MW configurations, https://www.pnnl.gov/projects/esgc-cost-performance
2 Iron-Air costs are taken as an average between: Net-Zero Power: Long Duration Energy Storage for a Renewable Grid, McKinsey, 2021; and Levi, P. et. al. Modeling Multi-Day Energy Storage in New York, Form Energy, 2023.

Summary of Energy Storage Costs





Mapping Candidate Resources to RESOLVE Zones

New Candidate Resource Regions using CAISO Study Areas

- The resource potential regions used in RESOLVE have been updated to align with the CAISO Study Areas used in transmission planning
  - Resource potential is assigned to substations, which are assigned to Study Areas in the CAISO White Paper[1]
- Assignments to RESOLVE zones are as follows:
  - PGE: North of Greater Bay Area (NGBA), Greater Bay Area (GBA), Fresno, Kern
  - SCE: Northern, Metro, North of Lugo (NOL), Eastern, East of Pisgah (EOP), Arizona
  - SDGE: Imperial, Arizona
- Arizona substations owned by the CAISO are divided between SCE and SDGE
- The GLW/VEA systems modeled as part East of Pisgah
- Candidate wind and geothermal resources near NVE-owned transmission lines in northeastern California are represented as a separate region

1 https://www.caiso.com/library/transmission-capability-estimate-inputs-for-cpuc-integrated-resource-plan-aug-29-2024

Comparison of Region Boundaries, 2023 vs 2025 I&A

Previous Work	2025 I&A[1]
Northern California Solano	PGE NGBA PGE GBA Northeast CA[2]
Southern PGAE Central Valley North Los Banos	PGE Fresno PGE Kern
Tehachapi	SCE Northern
Greater LA	SCE Metro
Greater Kramer	SCE NOL
Southern NV Eldorado	SCE EOP
Riverside	SCE Eastern
Greater SD Greater Imperial	SDGE Imperial
Arizona	SCE Arizona SDGE Arizona

Previous Work

2025 I&A

[1] Assignments are approximate
[2] Resources modeled in this region are assumed to interconnect to the NVE system and will require transmission investment to deliver to CAISO

Mapping Candidate Resources to RESOLVE Zones

- For solar, onshore wind, geothermal, enhanced geothermal, and location-constrained LDES (12-hr), candidate project areas are geospatially assigned to a CAISO Study Area, which determines their IOU and Zone
- Northeast CA and out-of-state wind and geothermal resources are assigned based on their specified tie-in locations to the CAISO system
- All offshore wind is in PGE territory
- County-level biomass potentials are split between PGE, SCE, and SDGE
- All distributed solar is split between IOUs based on service territory area
- Candidate Shed DR resources are not assigned to IOUs because these resources are modeled for their reliability attributes and are not dispatchable in RESOLVE
- For all other candidate resources (storage, gas), the old candidate resources have been "triplicated" to create three candidate resources representing builds within each IOU area

Resource Potential and Land Use Constraints

Process for Developing Resource Potential

Raw Resource Potential	Techno-Economic Screen	Environmental Screen

• Solar insolation
• Wind speed
• Known geothermal fields
• EGS temperature-at-depth estimates
• Pumped hydro storage sites
	• Minimum capacity factor thresholds
	• Ground slope
	• Urban areas and population density
	• Feasibility screens (e.g. setback from airports)
		• CEC Core Land-Use Screen:
		  • Protected areas
		  • Farmland
		  • Habitats
		  • Endangered species

Techno-Economic Land-Use Screening Criteria

Criterion	Screening Threshold or Exclusion Setback		
	Solar	Wind	Deep Enhanced Geothermal (EGS)
Slope	> 10°	> 10°	N/A
Population Density	> 100/km²	> 100/km²	> 100/km²
Capacity Factor	< 16% (DC)	< 30% (2)	> 80th percentile of extractable energy (MW/km³)
Interconnection Distance	>30 miles	>30 miles	>30 miles
Urban Areas	< 500 m	< 1,000 m	< 1,000 m
Water Bodies	< 250 m	< 250 m	< 250 m
Railways	< 30 m	< 250 m	N/A
Major Highways	< 125 m	< 125 m	N/A
Airports	< 1,000 m	< 5,000 m	< 1,000 m
Active Mines	< 1,000 m	< 1,000 m	< 1,000 m
Military Lands	< 1,000 m	< 3,000 m	< 1,000 m
Existing Project Footprints	Excluded	Excluded	Conventional (Hydrothermal) areas removed

- A new wind capacity factor raster from the latest NLR publication was incorporated, resulting in a higher threshold than previous cycles (28%)
- Conventional geothermal potentials are characterized from published results that have already factored in relevant techno-economic data

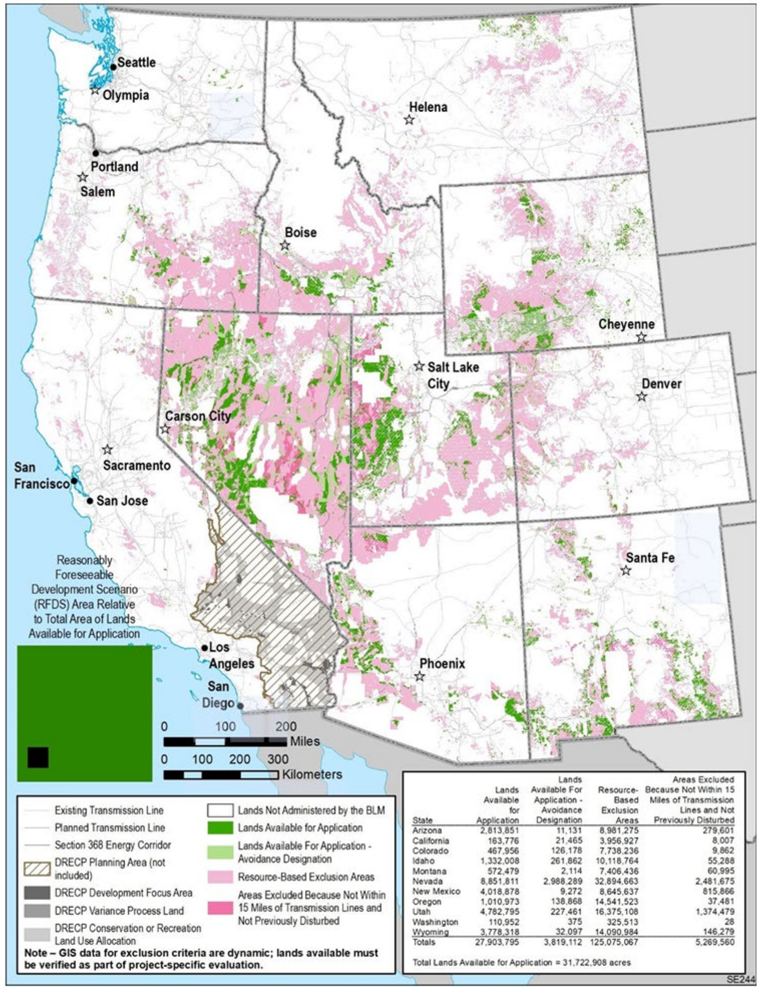
Environmental Land-Use Screening Criteria

- For regions of study within California, the 2025 I&A continues to use the CEC 2023 Land-Use Screens for Electric System Planning[1]
  - Solar and wind: Core Land-Use Screens
  - Geothermal: Geothermal Resource Potential by Field
  - EGS: Protected Areas Exclusion
- For out-of-state areas (NV, AZ, OR, ID, UT, WY), WECC Environmental Risk Classes 3 and 4 are excluded[2]

[1] CEC 2023 Land-Use Screens for Electric System Planning
[2] WECC Environmental and Cultural Considerations

BLM Final PEIS for Utility Solar

- In December 2024, BLM released a Record of Decision for its updated Western Solar Plan (2024 WSP)[1]
- The 2024 WSP applies resource-based exclusions for biological, environmental, or recreational conservation[2], leaving roughly 30 million acres of land available for solar application across the Western U.S.
- Lands with slopes greater than 10%, or that are greater than 15 miles from existing or planned transmission lines, are excluded from development unless previously disturbed
- The utility-scale solar resource potentials have been updated to reflect land availability with and without application 2024 WSP exclusions



State	Lands Available for Application	Lands Available For Application - Avoidance Designation	Resource-Based Exclusion Areas	Areas Excluded Because Not Within 15 Miles of Transmission Lines and Not Previously Disturbed
Arizona	2,813,851	11,131	8,981,275	279,601
California	163,776	21,465	3,956,927	8,007
Colorado	467,956	126,178	7,738,236	9,862
Idaho	1,332,008	261,862	10,118,764	55,288
Montana	572,479	2,114	7,406,436	60,995
Nevada	8,851,811	2,988,289	32,894,663	2,481,675
New Mexico	4,018,878	9,272	8,645,637	815,866
Oregon	1,010,973	138,868	14,541,523	37,481
Utah	4,782,795	227,461	16,375,108	1,374,479
Washington	110,952	375	325,513	28
Wyoming	3,778,318	32,097	14,090,984	146,279
Totals	27,903,795	3,819,112	125,075,067	5,269,560

Total Lands Available for Application = 31,722,908 acres

Figure 3-1. BLM-Administered Lands Excluded and Available for Application in the 11-State Planning Area under the Approved Plan.

[1] *BLM 2024 Solar Programmatic EIS, December 2024*
[2] *Table 3-2 of Solar PEIS Record of Decision*
Figure borrowed from (2)

Impact of BLM 2024 WSP on Solar Resource Potential

2022-23 I&A Solar Resource Potential Basemap

BLM Final WSP Exclusions (Approved December 2024)

Solar capacity reduces by 59% within the SCE EOP region with inclusion of the final PEIS land area exclusions

Solar capacity reduces by 54% and 35% within the SCE Arizona and SDGE Arizona regions, respectively, with inclusion of the final PEIS land area exclusions

IRP previously applied an 80% discount to solar potential. Given targeted nature of new WSP, Staff are proposing to remove the discount factor for regions dominated by the WSP and/or DRECP

Solar Resource Potential

- In the 2023 I&A, the in-state solar resource potentials were calculated using the CEC Core Land-Use Screens
  - Additional 80% discounts were applied to account for overall feasibility to develop (not reflected in 1st column at right)
- After incorporating updated CEC datasets[1] and evaluating the BLM 2024 WSP exclusions, an additional 50% reduction is recommended for regions that are not significantly impacted by the BLM 2024 WSP and fall outside the DRECP:
  - All PGE areas
  - SCE Northern
  - SCE Metro

Resource Regions	2023 I&A (MW)	BLM WSP (MW)	Reduction (%)[1]	2025 I&A (MW)[2]	Overall Reduction (%)
PGE NGBA	124,146	111,219	10%	55,768	**55%**
PGE GBA	38,741	40,123	-4%	19,903	**49%**
PGE Fresno	90,708	87,979	3%	44,113	**51%**
PGE Kern	53,678	55,663	-4%	27,708	**48%**
SCE Northern	44,467	46,267	-4%	22,959	**51%**
SCE Metro	1,017	859	16%	429	**58%**
SCE NOL	21,512	21,696	-1%	21,696	-1%
SCE Eastern	18,606	36,394	-96%	36,394	-96%
SCE EOP	72,653	29,530	59%	29,704	59%
SCE Arizona	91,812	42,194	54%	42,194	54%
SDGE Imperial	13,147	13,382	-2%	13,382	-2%
SDGE Arizona	68,813	44,402	35%	44,402	35%
Total	**639,301**	**445,857**		**358,653**	

[1] Negative reductions caused by updates to the CEC Core Land Use Screen, primarily fixes to the GAP analysis in SCE Eastern as part of an updated Base Exclusions layer, that were not reflected in the 2023 I&A
[2] Final values for 2025 I&A reflect additional reassignments of resource clusters due to transmission topology

In-State Wind Resource Potential

- The in-state wind resource potential is estimated by filtering candidate project sites that meet a minimum capacity factor (CF) threshold[1]
- For the 2025 I&A, the CF raster used for this sensitivity analysis was updated using the latest data from 2024 NLR RETP and Supply Curves[2]
- The 30% threshold is used for all in-state wind, as well as an additional 50% reduction to the East of Pisgah potential to reflect commercial interest
- Northeast CA wind interconnects to the NVE system and will require new transmission to deliver to CAISO

Minimum Capacity Factor Thresholds

Resource Regions	Previous I&A	28%	30%	32%	35%
Northeast CA	-	434	294	294	-
PGE NGBA	3,405	2,617	2,471	1,765	190
PGE GBA	832	327	231	204	204
PGE Fresno	2,728	2,681	2,228	-	-
PGE Kern	91	-	-	-	-
SCE Northern	1,732	1,701	1,701	1,541	1,467
SCE Metro	-	-	-	-	-
SCE NOL	1,046	849	797	605	549
SCE Eastern	165	165	165	165	92
SCE EOP (50% reduction)	711[3]	1,597	1,399	897	641
SDGE Imperial	251	251	251	251	133
SDGE Baja California[4]	1,654	1,654	1,654	1,654	1,654
Total (with 50% reduction to SCE EOP)	**13,434**	**12,275**	**11,191**	**7,375**	**4,930**

[1] *These capacity factors are not used elsewhere in IRP modeling*
[2] *Renewable Energy Technical Potential and Supply Curves, NLR 2024, https://www.NLR.gov/docs/fy25osti/91900.pdf*
[3] *80% reduction in previous I&A*
[4] *Informed by active projects in the CAISO interconnection queue*

Out-of-State Wind Resource Potential

- The out-of-state wind potentials reflect the total that could be delivered via new transmission lines by 2045
- Resource potentials are divided into tranches to reflect the timing and cost of new 500-kV transmission lines
- Likely tie-in locations for out-of-state wind were identified through review of in-development transmission projects and the CAISO 20-Year Transmission Outlook[1]
- Utah Wind has been removed as a candidate resource for the 2025 I&A

Resource	Tie-in Location	IOU	Transmission Upgrade(s)	Total Potential (MW)	First Available Year
New Mexico Wind	Palo Verde 500 kV	SCE	SunZia, RioSol, Generic (2)	5,936(4)	2026-2040
New Mexico Wind	Lugo 500 kV	SCE	Generic (2)	3,000	2038
Wyoming Wind	Eldorado 500 kV	SCE	TransWest, Generic (2)	5,000	2029-2036
Wyoming Wind	Tesla 500 kV	PGE	Generic (2, 3)	4,000	2036-2040
Idaho Wind	Harry Allen 500 kV	SCE	SWIP-North	1,100	2027

[1] *CAISO 20-Year Transmission Outlook (2023-2024), https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook-2023-2024*
[2] *Generic upgrade options, sizing, and cost taken from (1). First available year for generic options set to 2035-2036.*
[3] *The generic upgrade identified in (1) for Wyoming Wind to Tesla was duplicated to create a 2nd tranche of out-of-state wind in 2040.*
[4] *Excludes 1,585 MW of SunZia Wind reported as "In Development" in the CPUC Generator Baseline.*

Offshore Wind Resource Potential

- The offshore wind resource potential was calculated using the site areas and recommended area density factors from the June 2022 AB 525 NLR presentation[1]
- Values are calculated using the "High" Density Factor of 5 MW/km^2
- The Diablo Canyon Call Area has been removed from consideration for the 2025 I&A

Site	Area (km^2)	Potential (MW)	First Available Year
Morro Bay	975	4,875	2036
Humboldt Bay	536	2,680	2041
Cape Mendocino Study Area	2,072	10,360	2041
Del Norte Study Area	2,202	11,010	2041
Total	**7,226**	**28,925**	

(1) *CEC Docket 17-MISC-01. https://efiling.energy.ca.gov/GetDocument.aspx?tn=243707&DocumentContentId=77539*

In-State Geothermal Resource Potential

- The in-state geothermal resource potential comes from the latest CEC geospatial data layer containing footprints of known geothermal fields[1]
- After accounting for existing projects, planned development, and protected area exclusions, a total of 33 geothermal fields are identified and grouped by region
- Geothermal fields in IID service territory area (reported here under SCE Eastern and SDGE Imperial) are assumed to be available for procurement, with tie-in locations at Mirage and Imperial Valley
  - Northeast CA Geothermal and SCE Eastern Geothermal (delivered to Mirage) will incur additional transmission costs

Resource Regions	Conventional Geothermal Potential, MW
Northeast CA	178
PGE NGBA	668 (2)
SCE NOL	142
SCE Eastern	1,883 (3)
SDGE Imperial	529
Total	**3,399**

[1] *Geothermal Resource Potential by Field*, CEC 2024
[2] *Excludes 18 MW at the Geysers reported as "In Development" in the CPUC Generator Baseline.*
[3] *Excludes 44 MW near the Salton Sea reported as "In Development" in the CPUC Generator Baseline.*

Out-of-State Geothermal Resource Potential

- The out-of-state geothermal potentials reflect the totals based on **identified hydrothermal fields** in Nevada[1], Oregon[1], and Utah[2]
- Likely tie-in locations for out-of-state resources were identified through review of in-development transmission projects in the WECC, the CAISO 20-Year Transmission Outlook, and geothermal projects currently in development
- Pacific Northwest Geothermal has been renamed to Oregon Geothermal

Resource	Tie-in Location	Zone	Transmission Upgrade(s)	Total Potential (MW) (% of total)	First Available Year
Nevada Geothermal	Eldorado 500 kV	SCE	Generic (3)	290 (20%)	2035
Nevada Geothermal	Control 230 kV	SCE	Generic (3)	435 (30%)	2032
Nevada Geothermal	Beatty 230 kV	SCE	Generic (3)	435 (30%)	2032
Nevada Geothermal	Malin 500 kV	PGE	Generic (3)	290 (20%)	2035
Utah Geothermal	Eldorado 500 kV	SCE	Generic (3)	184	2030
Oregon Geothermal	Malin 500 kV	PGE	Generic (3)	520	2030

[1] Lovekin, J. and Pletka, R. Geothermal Assessment as Part of California's Renewable Energy Transmission Initiative (RETI). GeothermEx, 2009.
[2] USGS Western United State Geothermal Favorability. USGS, 2019. https://www.usgs.gov/tools/western-united-states-geothermal-favorability.
[3] Generic upgrade options and first available years reflect hypothetical high-voltage transmission lines from the hydrothermal field to the above tie-in location.

All out-of-state near-field EGS resources have the same first available years as shown above.
All out-of-state deep EGS resources have a first available year of 2035.

Mapping the Out-of-State Resources to CAISO

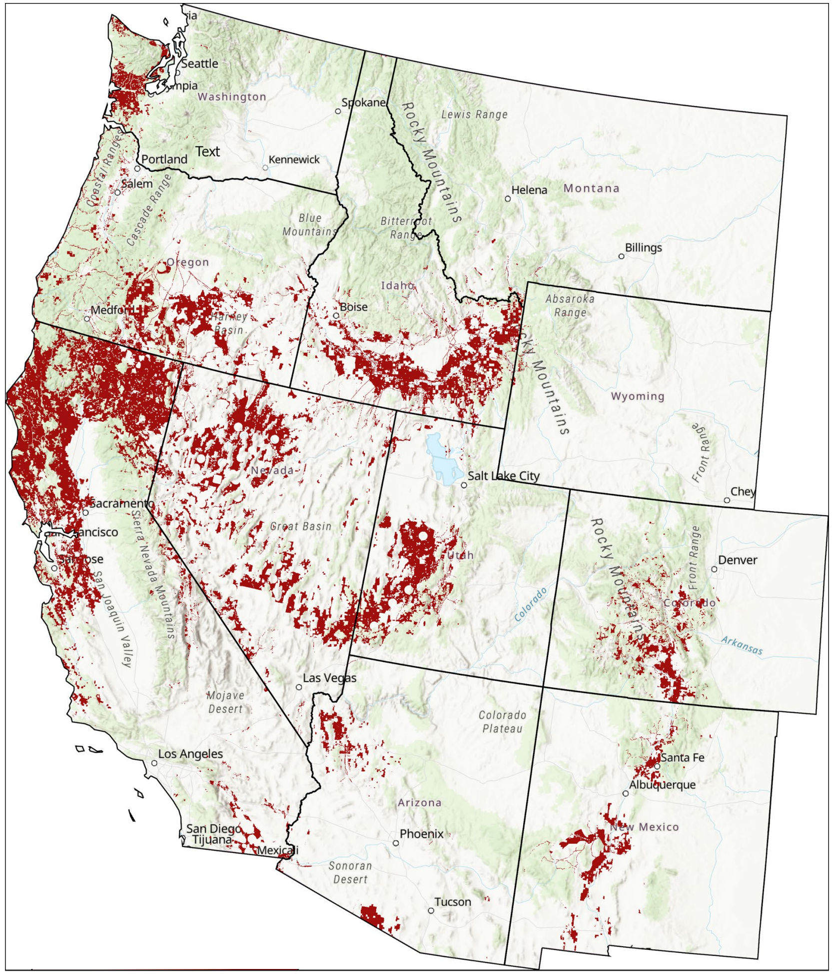
Resource	Tie-in Location	Zone	First Year(s)
New Mexico Wind	Palo Verde	SCE	2026-2035
New Mexico Wind	Lugo	SCE	2035
Wyoming Wind	Eldorado	SCE	2029-2036
Wyoming Wind	Tesla	PGE	2036-2040
Idaho Wind	Harry Allen	SCE	2027
Nevada Geothermal	Eldorado	SCE	2035
Nevada Geothermal	Control	SCE	2032
Nevada Geothermal	Beatty	SCE	2032
Nevada Geothermal	Malin	PGE	2035
Utah Geothermal	Eldorado	SCE	2030
Oregon Geothermal	Malin	PGE	2030

All out-of-state near-field EGS resources have the same first available years as shown above.
All out-of-state deep EGS resources have a first available year of 2035.

Enhanced Geothermal (EGS) Resource Potential

- New to the 2025 I&A, enhanced geothermal resource potentials for both "Near-Field" and "Deep" project types have been estimated
- Deep EGS methodology developed by Staff follows previous work from Princeton[1], NLR[2], and Stanford[3] to estimate extractable heat from temperature-at-depth data
- The near-field EGS resource potential, following NLR[2], assumes that the potential from known conventional (hydrothermal) project sites can be used for near-field EGS, effectively doubling the potential available at those sites (for additional cost)

Deep EGS Resource Potential



[1] Ricks, W. and Jenkins, J. D. Princeton, 2024. https://zenodo.org/records/13821073.
[2] Augustine, C. et. al. NLR, 2023. https://www.NLR.gov/docs/fy23osti/84822.pdf.
[3] Aljubran, M. and Horne, R. Stanford, 2024. https://gdr.openei.org/submissions/1592.

Near-Field EGS Resource Potential

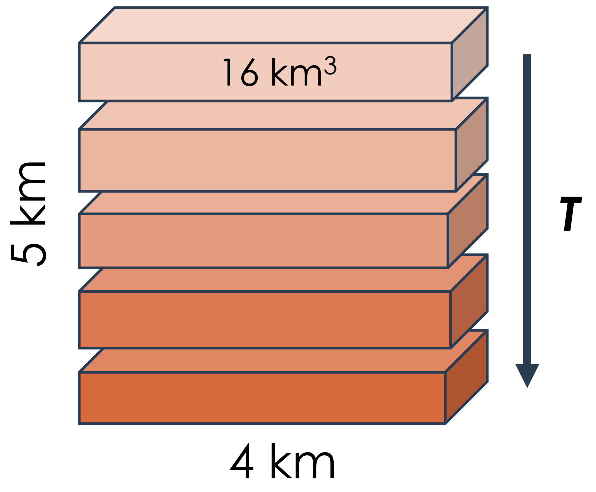
- Near-Field EGS resources are assumed to represent next-generation geothermal projects under consideration in California and neighboring states
- The in-state near-field EGS resource potential, following NLR[1], is assumed to be equal to the hydrothermal resource potential
    - Northeast CA EGS and SCE Eastern EGS (delivered to Mirage) will incur additional transmission costs
- The out-of-state near-field EGS potential is assumed to match the "Mean" Undiscovered Resources as reported in USGS Fact Sheet 2008-3082[2]

Region	Hydrothermal Potential (MW)	Near-Field EGS Potential (MW)
Northeast CA	178	178
PGE NGBA	668 (3)	668
SCE NOL	142	142
SCE Eastern	1,883 (4)	1,883
SDGE Imperial	529	529
Nevada	1,451	4,364
Utah	184	1,464
Oregon	520	1,893
Idaho	-	1,872
Total	**5,554**	**12,992**

[1] *Augustine, C. et. al. NLR, 2023. https://www.NLR.gov/docs/fy23osti/84822.pdf.*
[2] *Williams, C. et. al. USGS, 2008. https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.*
[3] *Excludes 18 MW at the Geysers reported as "In Development" in the CPUC Generator Baseline.*
[4] *Excludes 44 MW near the Salton Sea reported as "In Development" in the CPUC Generator Baseline*

Deep EGS Resource Potential Methodology

1. Temperature-at-depth estimates in 1-km bands at depths ranging from 3km-7km taken from Stanford[1] (4-km resolution)
2. NLR study[2] used to estimate the potential electric capacity (MW/km^3) for each cell (T > 150°C)
3. Cells with total potential (across all depths) below the 80th percentile (WECC-wide) are dropped to account for prioritization of high-yield project sites
4. Techno-economic (CPUC) and environmental (CEC) land-use screens are applied to remove unsuitable project sites



Resource Temp Range	Rock Density	Rock Heat Capacity	Average Reservoir Temp Decline	Heat in Place	Recovery Factor	Recoverable Heat	Plant Life	Plant Efficiency	Potential Electric Capacity
(°C)	(kg/km^3)	(kJ$_{th}$/kg-°C)	(°C)	(MJ$_{th}$/km^3)	%	(MJ$_{th}$/km^3)	(years)	%	(MW$_e$/km^3)
T	ρ_{rock}	C_p	ΔT	Q_{rock}	R_g	Q_{th}		η_{net}	W_e
150-175	2.55E+12	1	10	2.55E+13	20%	5.1E+12	30	11%	0.59
175-200	2.55E+12	1	10	2.55E+13	20%	5.1E+12	30	12.5%	0.67
200-225	2.55E+12	1	10	2.55E+13	20%	5.1E+12	30	14%	0.75
225-250	2.55E+12	1	10	2.55E+13	20%	5.1E+12	30	15%	0.81
250-275	2.55E+12	1	10	2.55E+13	20%	5.1E+12	30	16%	0.86
275-300	2.55E+12	1	10	2.55E+13	20%	5.1E+12	30	17%	0.92
300-325	2.55E+12	1	10	2.55E+13	20%	5.1E+12	30	18%	0.97
325-350	2.55E+12	1	10	2.55E+13	20%	5.1E+12	30	20%	1.08
>350	2.55E+12	1	10	2.55E+13	20%	5.1E+12	30	22%	1.19

[1] Aljubran, M. and Horne, R. Stanford, 2024. https://gdr.openei.org/submissions/1592.
[2] Augustine, C. NLR, 2016. https://www.osti.gov/biblio/1330935.

Enhanced Geothermal Resource Potential Totals

- EGS is assumed to be available for procurement in California, Oregon, Nevada, Idaho, and Utah
- Near-field EGS potential is set equal to the conventional (hydrothermal) potential and will be represented via discrete project locations in RESOLVE
- For deep EGS, only the in-CAISO (including IID) 3-km potential will be used in IRP modeling; all out-of-state deep EGS (including Northeast CA) will be excluded
- The representation of deep EGS on transmission will be generalized to one cluster per zone/IOU
- All non-CAISO EGS will incur additional transmission costs to deliver to the CAISO system

Resource Region	Near-Field EGS (MW)	Deep EGS (3 km) [1,2]
PGE	668	15,461
SCE	2,025	1,115
SDGE	529	438
CAISO Total	3,224	17,016
Northeast CA[3]	178	4,264
Nevada[3]	4,364	11,531
Oregon[3]	1,893	5,863
Idaho[3]	1,872	10,727
Utah[3]	1,464	6,130

[1] In-state totals reflect amounts within 30 miles of electrical substation. Out-of-state totals reflect total potential.

[2] Based on the amount of Deep EGS potential at 3-km depth, and the incremental drilling costs to access EGS at deeper depths, only the Deep EGS potential at 3-km will be modeled in RESOLVE

[3] Transmission pathways for non-CAISO EGS are assumed to be identical to those for hydrothermal resources

Location-Constrained LDES Resource Potential

- Location-constrained LDES includes both candidate pumped hydro sites and proposed A-CAES projects
- The list of projects was informed by data in the latest 25-26 TPP Busbar Mapping dashboard[1]
- All Location-Constrained LDES resources use the NLR 2024 ATB "One New Reservoir" Cost Class 3 for resource cost assumptions
- Project names and types have been anonymized to avoid deference to specific projects and allow for further study during the busbar mapping process

CAISO Study Area	Substation	Potential (MW)
PGE NGBA	Malin 500kV	393
PGE NGBA	Delevan 230kV	67
PGE GBA	Bellota 230kV	1,400
PGE Fresno	Gregg 230kV	140
PGE Kern	Magunden (PGE) 115kV	1,000
PGE Kern	Mesa (PGE) 230kV	300
PGE Kern	Templeton 230kV	750
SCE Northern	Bailey 230kV	500
SCE Northern	Whirlwind 230kV	2,100
SCE Northern	Windhub 230kV	480
SCE NOL	Lugo 230kV	500
SCE Eastern	Alberhill 115kV	500
SCE Eastern	Red Bluff 500kV	1,300
SCE EOP	Eldorado 230kV	500
SDGE Imperial	Sycamore Canyon 230kV	500
	Total	10,430

[1] Full Dashboard for the PD 25-26 TPP Base Case, 1/10/2025

Near-Term Solar and Wind Build Limits

- Staff has increased the near-term solar build limit to 4,000 MW per year for the first three years, based on data from LBNL Tracking the Sun[1] and the CAISO Master Generating Capability List (MGC)[2]
- New to this IRP cycle, staff have developed a build limit for in-state wind reflecting commercial interest and project deployment timelines
  - 250 MW/year through 2030, 1,000 MW/year from 2031 to 2035
- The full resource potential, subject to resource-level near-term build limits and transmission deliverability constraints, will continue to restrict capacity additions after these constraints are relaxed

Technology	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036+
Utility-Scale Solar	4,000	8,000	12,000	Full potential							
In-State Wind	250	500	750	1000	1,250	2,250	3,250	4,250	5,250	6,250	Full

1 https://emp.lbl.gov/utility-scale-solar; 2 http://oasis.caiso.com/mrioasis/logon.do

Near-Term Wind Resource Build Limits

- Additional restrictions for wind resources were identified by reviewing the CAISO interconnection queue, Cluster 15 project queue, and queues from neighboring jurisdictions; these limits restrict wind procurements up until 2035

Resource	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Northeast CA Wind	300	300	300	300	300	300	1,015	1,015	1,015	Full Potential
PGE NGBA Wind	0	206	206	206	206	206	206	206	206	
PGE GBA Wind	266	266	990	990	1,399	1,399	1,399	1,399	1,399	
PGE Fresno Wind	80	80	80	80	80	80	292	292	292	
SCE Northern Wind	0	0	100	206	206	206	206	206	206	
SCE NOL Wind	0	213	213	316	316	316	316	316	316	
SCE Eastern Wind	0	0	0	0	676	676	676	676	676	
SCE EOP Wind	1,050	3,618	3,618	3,719	3,719	3,719	3,719	3,719	3,719	
SDGE Imperial Wind	0	0	194	194	194	700	1,701	1,701	1,701	
SDGE Baja California Wind	353	353	353	353	353	353	653	653	653	

Near-Term Geothermal Resource Build Limits

- Additional restrictions for geothermal resources were identified by reviewing the CAISO interconnection queue, Cluster 15 project queue, and queues from neighboring jurisdictions; these limits restrict geothermal procurements up until 2032

Resource	2026	2027	2028	2029	2030	2031	2032+
Northeast CA Geothermal	0	0	0	0	Full potential		Full Potential
PGE NGBA Geothermal	0	0	0	0	Full potential		
SCE NOL Geothermal	0	0	0	0	Full potential		
SCE Eastern Geothermal	83	140	357	671	Full potential		
SDGE Imperial Geothermal	0	83	83	83	Full potential		
PGE Oregon Geothermal	0	0	0	0	Full potential		
PGE Nevada Geothermal	0	0	0	0	Full potential		
SCE Nevada Geothermal	288	387	411	411	411	411	
SCE Utah Geothermal	0	40	40	80	Full potential		

Minimum Build Constraints for FR Modeling

- In recent PSP and TPP modeling, LSE plans developed after the 2022 Filing Requirements were forced into the RESOLVE model, both near- and mid-term (through 2035) plans
- For the 2025 filing requirements, staff intend to produce a least-cost portfolio in RESOLVE, and are not forcing in the previous LSE plans
- However, since the resource baseline (existing + in-development units) was finalized in 2024, LSEs have contracted for additional resources in the near-term (before 2030)
  - When the baseline was finalized, the latest LSE filings available was from December 1, 2023; stakeholders suggested including data from more recent filings
- Staff identified units on the latest (December 2024) LSE filings that are incremental to the baseline, and require RESOLVE to select these as minimum builds
  - Incremental units are mapped to the technology and candidate zone (e.g. PGE Fresno) level for minimum build constraints
  - Only "development" units are included, not generic "planned/new" or "review"

RESOLVE Minimum Builds: Summary by IOU Zone

- More detailed minimum builds by candidate zone are included in the RESOLVE package

PGE Minimum Builds (MW)

Technology	2026	2028
Battery Storage	823	1,327
Solar	209	724
Wind	148	148
Biomass	12	12
Geothermal	21	26

SCE Minimum Builds (MW)

Technology	2026	2028
Battery Storage	1,023	2,488
Solar	1,060	2,360
Wind	0	0
Biomass	0	0
Geothermal*	2	9

*Additional online by 2030 (49 MW total)

SDGE Minimum Builds (MW)

Technology	2026	2028
Battery Storage	492	666
Solar	160	260
Wind	0	0
Biomass	0	0
Geothermal	0	2

Resource Transmission, Deliverability, and Interconnection

Transmission Representation in RESOLVE

- The transmission constraints implemented in RESOLVE include:

  1. Transmission deliverability limits imposed on candidate resource builds
  2. CAISO-identified transmission upgrades available to increase the transmission capability limits
  3. Generic transmission upgrades available when CAISO-identified upgrades are exhausted or prohibitively expensive
  4. Interconnection limits and upgrades to distribute resource potential across the CAISO and avoid over-procurement

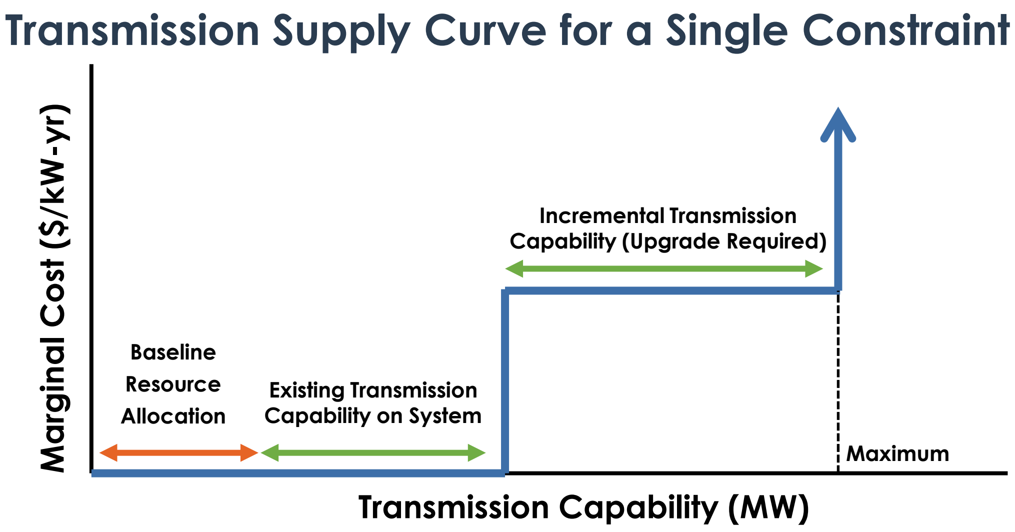
CAISO Transmission Modeling in RESOLVE

- The modeling of transmission constraints in RESOLVE is tied to the CAISO's representation of the transmission system in the TPP, and the annual Transmission Capability Whitepaper[1] provided to the CPUC ("CAISO Whitepaper")
- For each constraint examined, the CAISO provides data on existing transmission capability, identified upgrades to provide additional capability, project costs, and construction lead time
  - the full-capacity deliverable status (FCDS) for highest system need (HSN) and secondary system need (SSN) periods, derived from on-peak assessments, as well as the energy-only (EODS) period, derived from off-peak assessments
- Transmission diagrams and constraint mapping matrices are used to determine the constraint(s) that restrict power flow for each busbar

1 *Transmission Capability Estimate Inputs for CPUC Integrated Resource Plan*, CAISO, August 2024

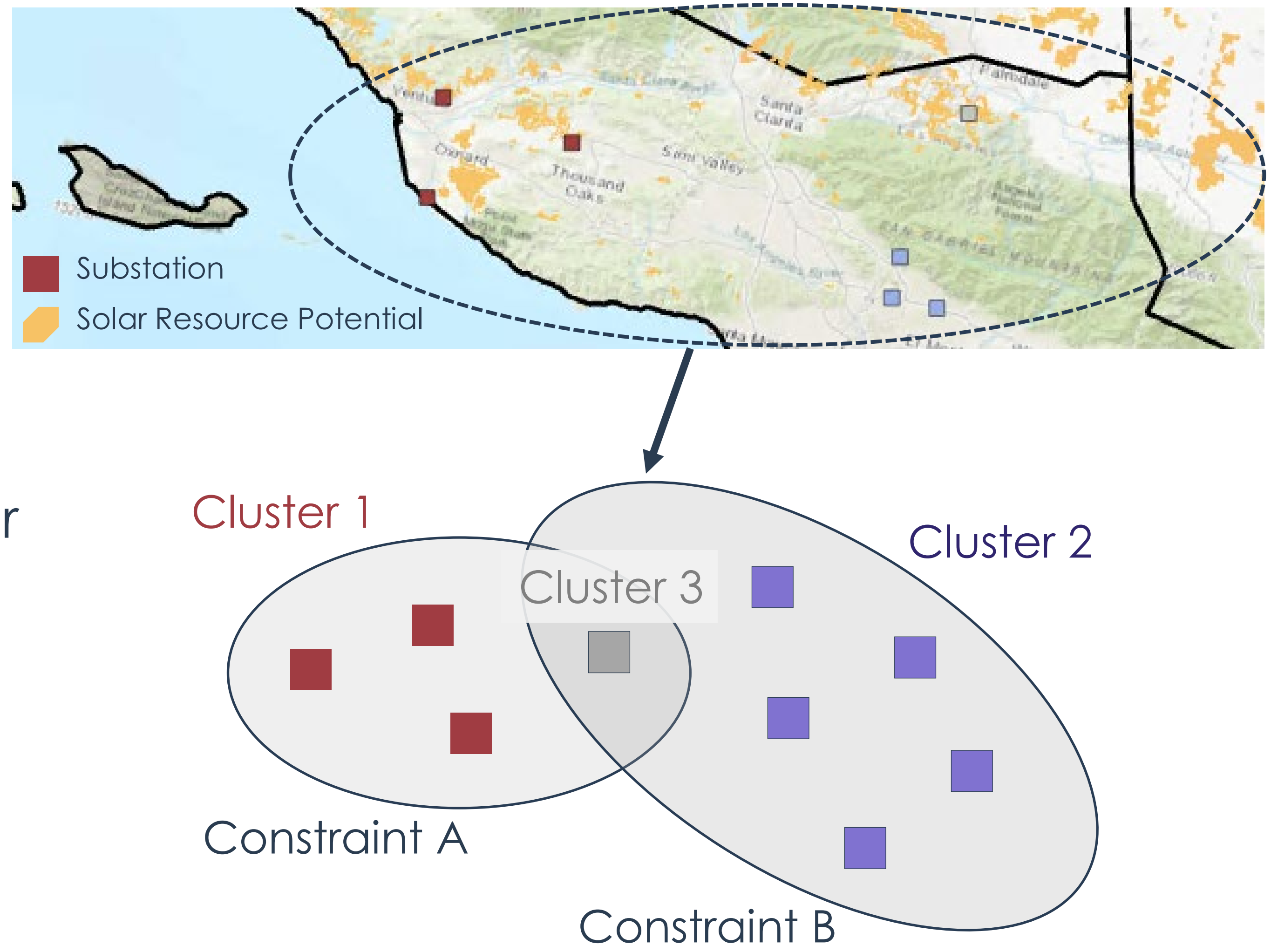
Reconciling CPUC and CAISO Modeling Baselines

- Transmission capability estimates provided in the CAISO Whitepaper were evaluated using a nodal generation model based on the existing generator capability as of 1/1/2024
- Any generators in the baseline with online dates after 1/1/2024 are not accounted for in the CAISO Whitepaper
  - The FCDS and EODS transmission utilization of those generators must be subtracted from the estimates reported in the CAISO Whitepaper



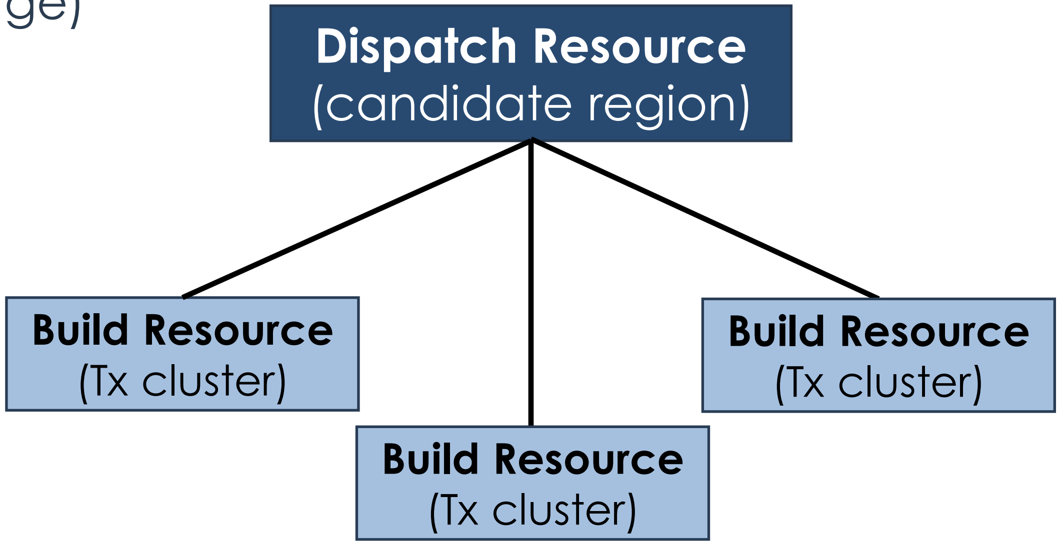
Candidate Resource Clustering in RESOLVE

- Resource potentials for most technologies are mapped to substations listed in the CAISO Whitepaper
- Substations are grouped into clusters based on their constraint memberships
- For each technology, each cluster represents a unique decision variable in RESOLVE, with a specified resource potential, first available year, and build cost



Role of Build and Dispatch Resources in RESOLVE

- CAISO transmission constraints are used to constrain the buildout of resources in RESOLVE, but are not enforced in RESOLVE's simplified dispatch algorithm
- All candidate resources in RESOLVE are represented by **dispatch resources** in each candidate region (e.g. PGE GBA); each dispatch resource is an aggregation of **build resources** at each transmission cluster
- Dispatch resources:
  - Contain operational data (e.g. profile, state of charge) that are used in RESOLVE's dispatch algorithm
  - Avoid false precision around resource quality in localized areas
- Build resources:
  - Contain resource potential, cost, first available year, and constraint membership data
  - Mirror the representation of the transmission system used in busbar mapping, ensuring that RESOLVE's resource builds satisfy the CAISO transmission constraints across all three deliverability windows



Generic CAISO Transmission Upgrades

- The upgrades identified in the CAISO Whitepaper may be insufficient to accommodate the resource additions required to meet system needs by 2045
- Generic transmission upgrades are included in RESOLVE to permit additional resource builds:
  - 500 MW of incremental capability per year is made available starting in 2037
- Generic upgrades may be triggered if all the capability on the CAISO constraints are exhausted, or if the unselected CAISO upgrades are cost-prohibitive to build

CAISO Study Area	Linearized Cost* (2024 $/kW-yr)
PGE NGBA PGE GBA	$62.44
PGE Fresno PGE Kern	$62.44
SCE Northern	$62.44
SCE Metro	$93.66
SCE NOL	$62.44
SCE Eastern SCE Arizona SDGE Imperial SDGE Arizona	$93.66
SCE EOP	$62.44

*Costs derived from generic assumptions for a new 500 kV transmission line, approximately $1 Billion per GW capacity

Out-of-State Transmission Deliverability

- Candidate resources that do not interconnect directly to the CAISO system are termed "out-of-state resources" in RESOLVE modeling
- To represent the transmission impacts for each out-of-state resource, Staff determines:
  - The likely point(s) (substations) where each out-of-state resource will tie into the CAISO system;
  - The near- and medium-term limits on total deliverable power (resource build limits), given planned transmission development across the WECC; and
  - The cost to deliver those resources to the CAISO system border, including new transmission investment and wheeling charges, where applicable
- Tie-in locations are informed by the busbar mapping analysis in coordination with the CAISO
- Resource build limits and deliverability cost adders are informed by in-development transmission projects in the WECC and previous CAISO studies, including the 20-Year Transmission Outlook[1] and recent TPP reports
- For resources where no suitable representative transmission projects are identified, generic costs are developed using the IOU per-unit cost guides

[1] *20-Year Transmission Outlook (2023-2024), CAISO, July 2024*

Out-of-State Wind Transmission Candidates

Project Name	Project Status	RESOLVE Resource	Tie-In Location	IOU	First Available Year	Capacity, MW	Line Cost, $/kW-yr	Wheeling Cost, $/kW-yr	Total Cost, $/kW-yr
Hilltop to Malin + NVE Wheeling	Generic [2]	Northeast CA Wind	Malin	PGE	2026	294	*30.62*	*29.64* [5]	*60.26*
SunZia I (Entitled)	In-Development*	New Mexico Wind	Palo Verde	SCE	2026	546 [3]	*81.93*	-	*81.93*
SunZia I (via SRP)	In-Development*	New Mexico Wind	Palo Verde	SCE	2026	890	*81.93*	*33.00* [4]	*114.93*
SunZia II – RioSol	In-Development*	New Mexico Wind	Palo Verde	SCE	2028	1500	*97.49*	*33.00* [4]	*130.49*
NM to Palo Verde	Generic [1]	New Mexico Wind	Palo Verde	SCE	2040	3000	*141.70*	-	*141.70*
NM to Lugo	Generic [1]	New Mexico Wind	Lugo	SCE	2038	3000	*107.90*	-	*107.90*
SWIP-North	In-Development*	Idaho Wind	Harry Allen	SCE	2027	1100	*67.31*	-	*67.31*
TransWest Express	In-Development*	Wyoming Wind	Harry Allen	SCE	2029	1500	*107.78*	-	*107.78*
TransWest Express	In-Development*	Wyoming Wind	Eldorado	SCE	2033	1500	*120.82*	-	*120.82*
WY to Eldorado	Generic [1]	Wyoming Wind	Eldorado	SCE	2036	2000	*206.15*	-	*206.15*
WY to Tesla	Generic [1]	Wyoming Wind	Tesla	PGE	2036	2000	*206.15*	-	*206.15*
WY to Tesla (2nd Tranche)	Generic [1]	Wyoming Wind	Tesla	PGE	2040	2000	*206.15*	-	*206.15*

Estimates for in-development projects collected from the 2021-2022 TPP and a recent SWIP-N Appplication Memo

[1] Costs reported in CAISO 20-Year Transmission Outlook, [2] New costs estimated using per-unit cost guides (CAISO 20-Year Outlook, GLW)
[3] Excludes 1,585 MW of in-development SunZia Wind in the CPUC Baseline Generator List, [5] SRP OATT, [6] NEVP OATT

Out-of-State Geothermal Transmission Candidates

Project Name	Project Status	RESOLVE Resource	Tie-In Location	IOU	First Available Year	Capacity, MW	Line Cost, $/kW-yr	Wheeling Cost, $/kW-yr	Total Cost, $/kW-yr
Hilltop to Malin + NVE Wheeling	Generic (2)	Northeast CA Geothermal, Near-Field EGS	Malin	PGE	2035	178	30.62	29.64 (4)	60.26
Bannister to Devers/Mirage	Generic (2)	SCE Eastern Geothermal, Near-Field EGS	Mirage	SCE	2026	1,883	39.63		39.63
NV to Control	Generic (2)	Nevada Geothermal, Near-Field EGS	Control	SCE	2032	uncapped	73.99	-	73.99
Silver Peak to Beatty	Generic (2)	Nevada Geothermal, Near-Field EGS	Beatty	SCE	2032	uncapped	73.99	-	73.99
Robinson Summit to Eldorado	Generic (1)	Nevada Geothermal, Near-Field EGS	Eldorado	SCE	2035	uncapped	46.39	-	46.39
Hilltop to Malin + NVE Wheeling	Generic (2)	Nevada Geothermal, Near-Field EGS	Malin	PGE	2035	uncapped	30.62	29.64 (4)	60.26
Utah to Eldorado	Generic (3)	Utah Geothermal, Near-Field EGS	Eldorado	SCE	2030	uncapped	47.84	-	47.84
Corral to Malin	Generic (2)	Oregon Geothermal, Near-Field EGS	Malin	PGE	2030	uncapped	61.83	-	61.83
Midpoint to Harry Allen	Generic *	Idaho Near-Field EGS	Harry Allen	SCE	2027	1100	*67.31*	-	*67.31*

Note: Out-of-state Near-Field EGS (NV, UT, OR, ID) are assumed to be delivered to the same locations as hydrothermal (or ID wind), with identical transmission cost adders.
**Estimate for Idaho EGS uses the SWIP-N costs from a recent SWIP-N Appplication Memo*

[1] *Costs reported in CAISO 20-Year Transmission Outlook*, [2] *New costs estimated using per-unit cost guides (CAISO 20-Year Outlook, GLW)*, [3] *2021-22 TPP*, [4] *NEVP OATT*

Interconnection Capacity Expansion in RESOLVE

- New to the 25-26 TPP and expanded for the 2025 I&A, each candidate resource cluster will be constrained by interconnection headroom
- Each busbar in a cluster is assigned a default capacity value based on its voltage
- The total headroom of each cluster is the sum of the capacities across all buses, and the total nameplate rating of all resources built within a cluster cannot exceed this value
- Clusters that primarily consist of busbars at or above 230 kV will be allowed to build new buses to expand the available headroom:
  - Costs for new busbars are estimated using the per-unit cost summary table from the 2024 CAISO 20-Year Outlook[1]
  - Reflecting a 5- to 7- year construction lead-time, interconnection upgrades will be available starting in 2032

Reference Values for Interconnection Expansion

Voltage (kV)	Default Capacity (MW)[2]	Incremental Capacity (MW)[2]	Cost, $MM[1]	Levelized Cost, $/kW-yr
115	100	N/A	-	-
138	100	N/A	-	-
161	100	N/A	-	-
230	1,500	1,500	$100	$5.20
500	3,000	3,000	$125	$3.25

[1] *20-Year Transmission Outlook (2023-2024), CAISO, July 2024*
[2] *Default and incremental capacity estimates were informed by values reported in an SCE Generator Interconnection Process Presentation, Sept 2021*

Load and Generation Profiles

23 Weather Year Profiles

- 23 weather years (2000-2022) are modeled to capture a wide range of variability in load and renewable generation
  - These weather years can also be used to determine weather-based derating of thermal units
- The previous cycle used weather years 1998-2020; sufficient data for 2021 and 2022 has become available since then
  - 1998 and 1999 are excluded from the updated weather year range because high resolution offshore wind data is only available from 2000 and forward

Load Profile Development

- Electric demand forecasts from CA regions are derived from the IEPR forecast
- Electric demand forecasts for non-CA regions are derived from IRP filings and FERC Form 714 data
- 23 weather year (2000-2022) load profiles used in SERVM and RESOLVE were developed with the steps shown to the right

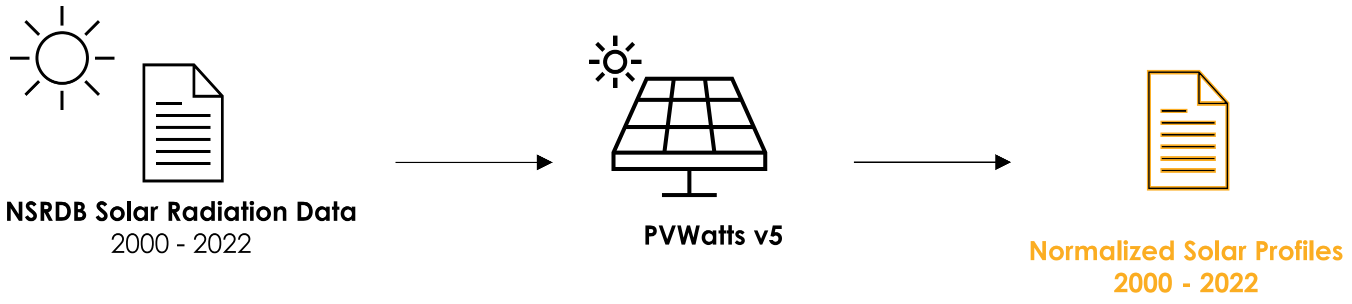
1. Gather historical weather data from locations across the Western US and CAISO Energy Management System (EMS) electricity sales data
2. Reconstitute historical consumption demand from sales by removing BTM PV effects, demand response events, and grid storage charging
3. Train a regression model using three years (2020-2022) of historical consumption demand and weather data
4. Use the model to build out 23 weather years (2000-2022) of hourly consumption demand profiles
5. Scale the consumption demand profiles such that the median across 23 weather years matches the annual peak and energy forecast
6. Add incremental demand modifiers (AAEE, AAFS, EVs, BTM PV, BTM Storage)

Hydro Parameters

- Staff developed monthly hydro parameters for SERVM using EIA historical settlement data for the modeled weather years (2000-2022), including:
    - Daily Energy Budget
    - Scheduled Flow Range: the max and min hydro dispatch on an average day
    - Capmax: the max hydro dispatch in the given month
- Monthly RESOLVE parameters for Pmax, Pmin, and Paverage are developed from the daily energy budget and scheduled flow range
- For this cycle, separate run-of-river and non run-of-river (scheduled) parameters were developed for CAISO Hydro resources to distinguish them for dispatch and ELCC modeling

SERVM Solar Profile Development

- Solar profiles are developed for clusters of solar resource locations in addition to specified city centers for BTM PV
- NLR’s System Advisor Model (SAM) PVWatts v5 calculator was trained on CAISO settlement data using NLR National Solar Radiation Database (NSRDB) for 23 Weather Years (2000-2022) to account for solar insolation and cloud cover by geographic location
- Profiles were created for fixed-tilt, single-axis and double-axis tracking, and BTM PV
- Utility-scale solar uses a default inverter loading ratio of 1.3 and BTM PV uses 1.13



SERVM Normalized Wind Profile Development

- **Velocity Approach**: Normalized hourly wind production profiles generated from hourly wind speed data along with an appropriate power response curve and a multiplicative transmission loss factor
  - All offshore, and onshore locations where production data is not available
  - Wind speed data:
    - Offshore: NLR National Offshore Wind (NOW) data set
    - Onshore: Copernicus ERA5 reanalysis dataset
- **Monte Carlo Approach**: Normalized hourly wind production profiles generated from random draws of aggregated, normalized, historical production then resorted by month based on nearest neighbor modeled wind speed profiles.
  - Ensures consistency with observed monthly historical wind production
  - Report by month imposes historical correlations with load and solar
  - Improvement over onshore velocity approach which can tend to systematically undervalue onshore wind production in periods of high load.

Evolution of CPUC Wind Model

- Current CPUC wind model v2023 approach optimizes:
  - Use of historical wind production data, when available
    - Previous versions attempted to develop normalized wind profiles from velocity profiles and response function, but the approach tends to systematically undervalue wind production in periods of high load
    - NLR NOW dataset will overcome some of these limitations for offshore production
  - Aggregated regions
    - In the previous version, generating onshore wind profile "weather stations" at excessively high spatial resolution tends to result in overestimating wind production potential due to diversity interactions between production profiles
    - The current wind model more accurately captures historical wind production, without adding excessive diversity interactions which cause wind production to be overestimated; as a result, the modeled wind production in certain locations has declined since the previous cycle

Candidate Solar Weather Station Assignments

Solar Resource	2023 I&A*	2025 I&A
PGE Distributed	CA_KERN_BAKERSFIELD	CA_SACRAMENTO
SCE Distributed	CA_KERN_BAKERSFIELD	CA_SANFERNANDO
SDGE Distributed	CA_KERN_BAKERSFIELD	CA_SANDIEGO
PGE Fresno	CA_KERN_LOSTHILLS	CA_FRESNO_TRANQUILLITY[1]
PGE GBA	CA_WILLITS	CA_MODESTO[1]
PGE Kern	CA_KERN_LOSTHILLS	CA_KERN_LOSTHILLS
PGE NGBA	CA_WILLITS	CA_SACRAMENTO[2]
SCE Eastern	CA_IMPERIAL_BRAWLEY	CA_RIVERSIDE_BLYTHE[2]
SCE EOP	NV_CLARK_89040	NV_CLARK_BOULDER
SCE Metro	CA_SANFERNANDO	CA_SANFERNANDO
SCE NOL	CA_SANBERNARDINO_ APPLEVALLEY	CA_SANBERNARDINO_ APPLEVALLEY
SCE Northern	CA_KERN_ROSAMOND	CA_KERN_ROSAMOND
SCE Arizona	AZ_PHOENIX	AZ_PHOENIX
SDGE Arizona	AZ_PHOENIX	AZ_PHOENIX
SDGE Imperial	CA_IMPERIAL_BRAWLEY	CA_IMPERIAL_BRAWLEY

(1) Updated for new resource regions in PGE
(2) Updated to reflect proximity to candidate project areas.

Weather Stations Selected for 2025 I&A

Yellow: 2025 I&A

*Candidate resources were different in the 2023 I&A; data represents that for the most analogous candidate to the current (2025 I&A) candidates

Candidate In-State Wind Weather Station Assignments

Wind Resource	2023 I&A*	2025 I&A
PGE Fresno	CA_MERCED_UNINCORPORATED	CSD_CASOLANO
PGE GBA	CA_CONTRACOSTA_PITTSBURG	CSD_CASOLANO
PGE Kern	CA_MERCED_UNINCORPORATED	CSD_CAKERN
PGE NGBA (1)	CA_SHASTA_SHINGLETOWN	EIA_OREGON
SCE Eastern	CA_SANDIEGO	CSD_CARIVERSIDE
SCE EOP (1)	CA_SANBERNARDINO_92332	EIA_ARIZONA
SCE NOL	CA_KERN_MOJAVE	CSD_CAKERN
SCE Northern	CA_KERN_MOJAVE	CSD_CAKERN
SDGE Imperial	CA_SANDIEGO	CSD_CARIVERSIDE
Northeast CA (1)	CA_SHASTA_SHINGLETOWN	EIA_OREGON

(1) PGE NGBA, Northeast CA, and SCE EOP are both assigned to out-of-state weather stations to retain adequate diversity for candidate wind.

In-State Wind Weather Stations

Red: 2025 I&A

*Candidate resources were different in the 2023 I&A; data represents that for the most analogous candidate to the current (2025 I&A) candidates

Baseline Solar Profiles – 2023 vs 2025 I&A

- Zonal disaggregation allows for representation of different capacity factors in each IOU planning area, compared to CAISO as a whole
- Largest differences in non-CAISO baseline solar are driven by corrections to mappings of baseline units to weather stations (e.g., mapped to closest station geographically)

CAISO Resource	2023 I&A (CAISO)	2025 I&A	Relative Delta
PGE Solar	30.7%	30.5%	-0.8%
SCE Solar	30.7%	33.9%	+10.2%
SDGE Solar	30.7%	32.1%	+4.3%

Non-CAISO Resource	2023 I&A	2025 I&A	Relative Delta
IID Solar	30.7%	30.5%	-0.8%
LDWP Solar	31.7%	27.8%	-12.3%
NCNC Solar	32.5%	30.6%	-5.8%
NW Solar	28.0%	22.1%	-21.1%
SW Solar	33.0%	32.2%	-2.3%

Separate profiles for remote resources excluded.

Candidate Solar Profiles – 2023 vs 2025 I&A

- There is generally good alignment on solar capacity factors between the 2023 I&A and 2025 I&A
- Largest differences are driven by new weather station assignments

Resource	2023 I&A*	2025 I&A	Relative Delta
PGE Distributed Solar	23.6%	24.7%	+4.8%
SCE Distributed Solar	23.6%	26.3%	+11.2%
SDGE Distributed Solar	23.6%	24.7%	+4.5%
PGE Fresno Solar	32.1%	31.5%	-2.0%
PGE GBA Solar	28.3%	31.4%	+11.2%
PGE Kern Solar	32.1%	33.0%	+2.8%
PGE NGBA Solar	28.3%	31.1%	+10.0%
SCE Arizona Solar	32.9%	33.0%	+0.3%
SCE Eastern Solar	34.2%	34.3%	+0.4%
SCE EOP Solar	33.1%	32.8%	-1.4%
SCE Metro Solar	31.8%	33.0%	+3.7%
SCE NOL Solar	34.8%	35.9%	+3.2%
SCE Northern Solar	34.8%	35.6%	+2.3%
SDGE Arizona Solar	32.9%	33.0%	+0.3%
SDGE Imperial Solar	34.2%	32.8%	-4.0%

*Candidate resources were different in the 2023 I&A; data represents that for the most analogous candidate to the current (2025 I&A) candidates

Baseline Wind Profiles – 2023 vs 2025 I&A

- Significant updates to wind weather stations and profiles
- Zonal disaggregation allows for representation of different capacity factors in each IOU planning area, compared to CAISO as a whole
  - Out-of-State Wind is also delineated for dispatch and ELCC modeling

CAISO Resource	2023 I&A (CAISO)	2025 I&A	Relative Delta
PGE Wind	32.1%	29.0%	-9.6%
SCE Wind (In-State)	32.1%	26.2%	-18.5%
SCE Wind (Out-of-State)	32.1%	37.6%	+17.3%
SDGE Wind	32.1%	25.1%	-21.9%

Non-CAISO Resource	2023 I&A	2025 I&A	Relative Delta
LDWP Wind	34.5%	33.1%	-4.0%
NCNC Wind	32.1%	28.8%	-10.2%
NW Wind	30.8%	26.0%	-15.6%
SW Wind	30.8%	31.4%	+2.1%

Separate profiles for remote resources excluded.

Candidate Wind Profiles – 2023 vs 2025 I&A

- Significant updates to wind weather stations and profiles
- Out-of-State Wind and North Coast Offshore Wind capacity factors decline
  - 2022 NLR OSW report shows similar capacity factors as 2025 I&A profiles

Offshore Resource	2023 I&A	2025 I&A	Relative Delta
PGE Cape Mendocino Offshore Wind	58.6%	56.0%	-4.4%
PGE Del Norte Offshore Wind	57.1%	53.1%	-7.0%
PGE Humboldt Bay Offshore Wind	57.7%	49.2%	-14.7%
PGE Morro Bay Offshore Wind	46.2%	46.4%	+0.6%

Onshore Resource	2023 I&A*	2025 I&A	Relative Delta
Northeast CA WInd	-	26.0%	-
PGE Fresno Wind	23.7%	28.8%	+21.4%
PGE GBA Wind	26.0%	28.8%	+11.0%
PGE Kern Wind	23.7%	25.1%	+5.6%
PGE NGBA Wind	22.1%	26.0%	+18.1%
PGE Wyoming Wind	49.4%	40.0%	-19.0%
SCE Eastern Wind	30.2%	32.1%	+6.6%
SCE EOP Wind	33.1%	30.4%	-8.0%
SCE Idaho Wind	33.9%	28.4%	-16.3%
SCE New Mexico Wind	46.4%	37.6%	-18.9%
SCE NOL Wind	28.6%	25.1%	-12.3%
SCE Northern Wind	28.6%	25.1%	-12.3%
SCE Wyoming WInd	49.4%	40.0%	-19.0%
SDGE Baja California Wind	30.2%	32.1%	+6.6%
SDGE Imperial Wind	30.2%	32.1%	+6.6%

*Candidate onshore resources were different in the 2023 I&A; data represents that for the most analogous candidate to the current (2025 I&A) candidates

Geothermal Ambient Temperature Derates

Overview of Geothermal Plant Operations

- Turbines at geothermal plants (both conventional and enhanced geothermal), especially binary systems, require active cooling and are sensitive to ambient air temperatures
  - Geothermal plant capacity factor is influenced by diurnal and seasonal air temperature variation (for air-cooled plants), technology (e.g., binary or flash), downtime, and internal plant energy losses
- Evaporative cooling is typically more effective than air-based cooling, but availability and performance in California will be site-specific
  - Evaporative cooling requires large volumes of water, which is a limiting factor across much of the west
- In locations where evaporative cooling is unavailable and/or ambient temperatures are high, larger thermal derates should be anticipated, which may **reduce output during the warmest hours** of the year and negatively **impact the reliability value** of the generator

Example: Anticipated Thermal Derates for Binary EGS in Nevada

- In locations where evaporative cooling is unavailable and/or ambient temperatures are high, larger thermal derates should be anticipated, with corresponding impacts on maximum output and ELCC
- Data are scarce, but Google's testimony on NVE's recent clean energy tariff for new geothermal[1] provides some insight into Fervo's Corsac Station (Deep-EGS-Binary) project output by month-hour:

Figure-Kobor-Direct-2: Corsac Project Heatmap

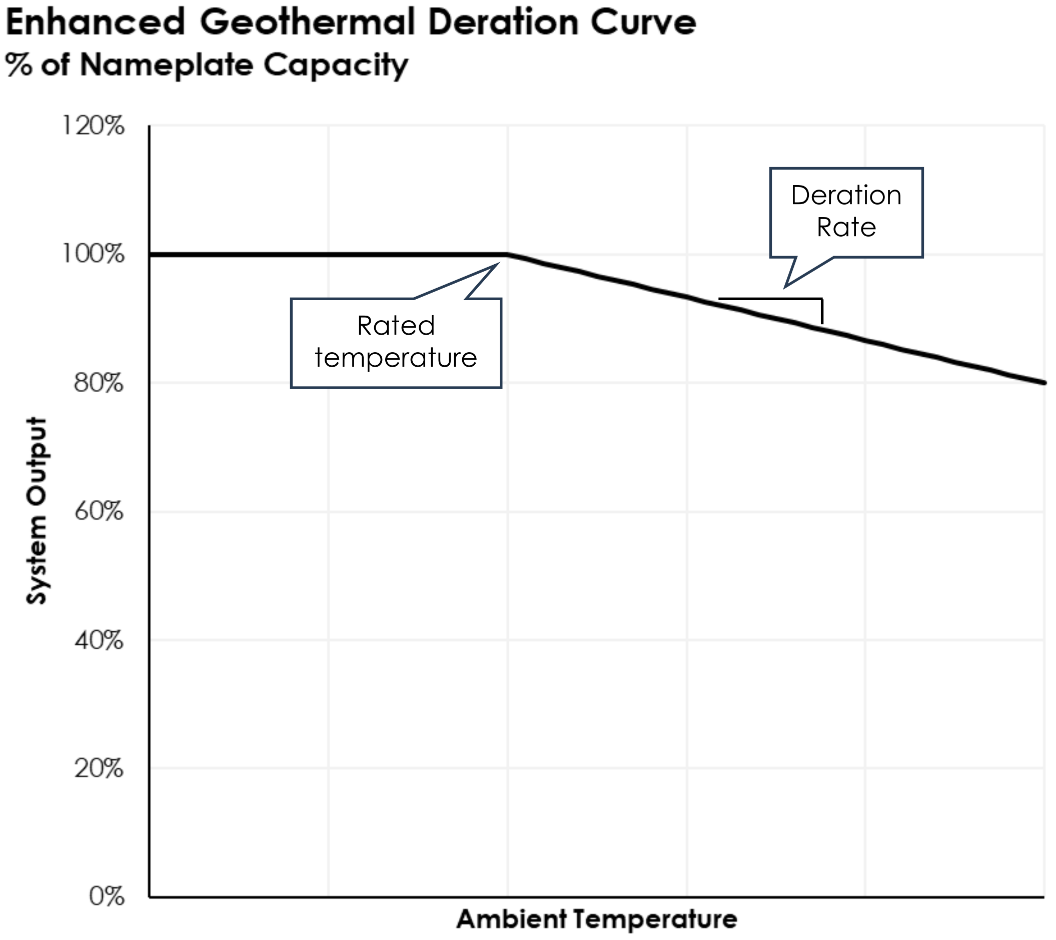
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	96%	97%	97%	97%	98%	98%	98%	99%	100%	100%	99%	99%	98%	96%	95%	94%	89%	90%	92%	94%	94%	95%	95%	96%
Feb	94%	94%	95%	95%	95%	96%	96%	98%	99%	99%	99%	98%	97%	95%	95%	93%	90%	86%	89%	91%	91%	92%	93%	93%
Mar	91%	92%	93%	93%	93%	94%	96%	99%	99%	98%	98%	97%	96%	94%	94%	94%	91%	83%	83%	86%	88%	89%	90%	90%
Apr	88%	89%	90%	90%	91%	92%	97%	97%	97%	97%	96%	95%	94%	93%	92%	89%	87%	82%	78%	81%	84%	85%	86%	87%
May	83%	84%	85%	86%	87%	92%	97%	96%	95%	93%	92%	90%	88%	87%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	78%	80%	81%	81%
Jun	76%	78%	79%	81%	82%	90%	93%	91%	89%	86%	84%	81%	80%	79%	77%	76%	75%	72%	67%	65%	70%	73%	74%	75%
Jul	70%	72%	73%	75%	77%	83%	88%	85%	82%	79%	76%	73%	72%	71%	69%	68%	66%	64%	59%	58%	64%	66%	68%	69%
Aug	72%	74%	76%	77%	79%	81%	89%	88%	84%	80%	77%	74%	72%	70%	70%	70%	68%	64%	58%	63%	67%	69%	70%	71%
Sep	80%	81%	82%	83%	84%	85%	93%	96%	92%	87%	83%	80%	79%	78%	78%	77%	74%	66%	67%	72%	75%	77%	78%	79%
Oct	88%	89%	90%	91%	91%	92%	94%	98%	96%	94%	90%	88%	86%	86%	86%	84%	77%	75%	79%	82%	84%	85%	86%	87%
Nov	93%	94%	94%	95%	95%	95%	96%	99%	99%	97%	96%	93%	91%	91%	91%	88%	82%	85%	88%	90%	90%	91%	92%	93%
Dec	97%	98%	98%	98%	98%	99%	99%	99%	100%	99%	99%	99%	98%	97%	96%	94%	90%	93%	94%	95%	95%	96%	97%	97%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

Local Hour Ending

[1] NV Energy and Callisto Joint Application for Approval of an Energy Supply Agreement, June 2024

General Deration Model to Estimate EGS System Output

- Enhanced geothermal systems (EGS) are assumed to experience **linear deration to system output** as a function of temperature
  - The linear coefficient is assumed to be **0.667%/°C**, based on Staff review of geothermal production estimate models and other data
- The rated temperature is assumed to match the lowest average daily temperature for each weather station and historical weather year in the dataset
  - Each weather year is assigned its own rated temperature
- The deration curve is applied to historic weather year temperature data to produce hourly EGS profiles for use in SERVM and RESOLVE

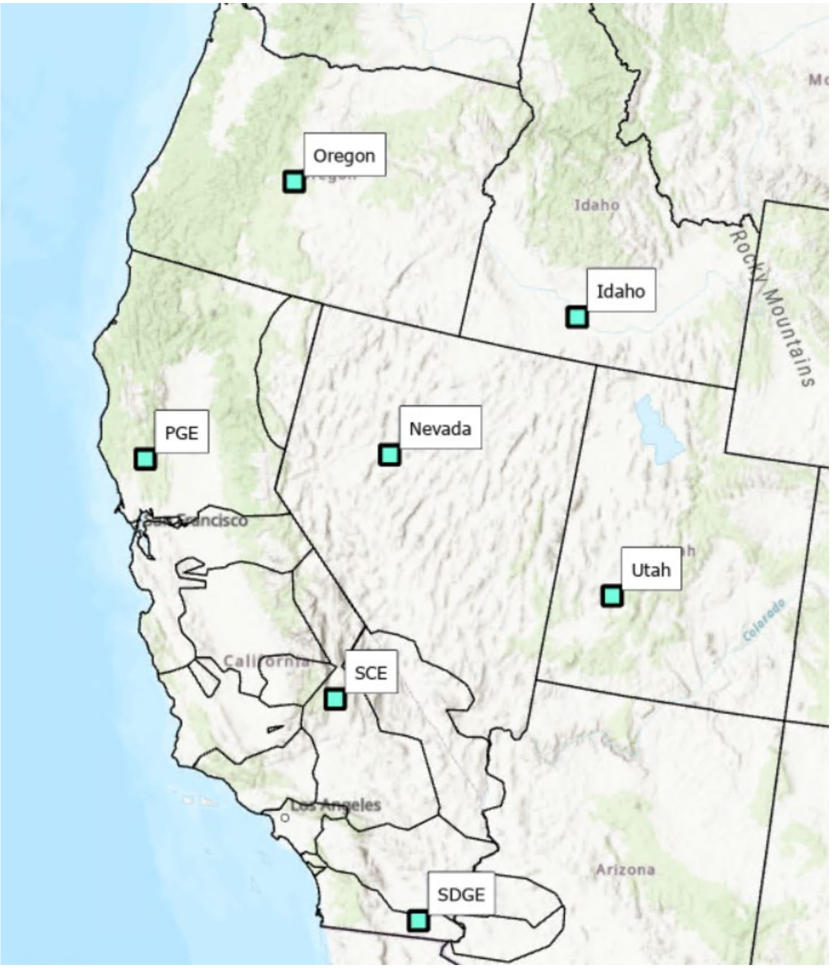


Candidate EGS Weather Station Assignments

Weather data from weather stations used in the CPUC ERM thermal ambient derate model were used to develop ambient derate profiles for candidate EGS resources (both near-field and deep)

EGS Region	Nearest Hydrothermal System
PGE	Geysers
SCE	Coso
SDGE	Brawley / Salton Sea
Nevada	Dixie Valley
Utah	Roosevelt HS / Cape Station
Idaho	Not modeled
Oregon	Central OR

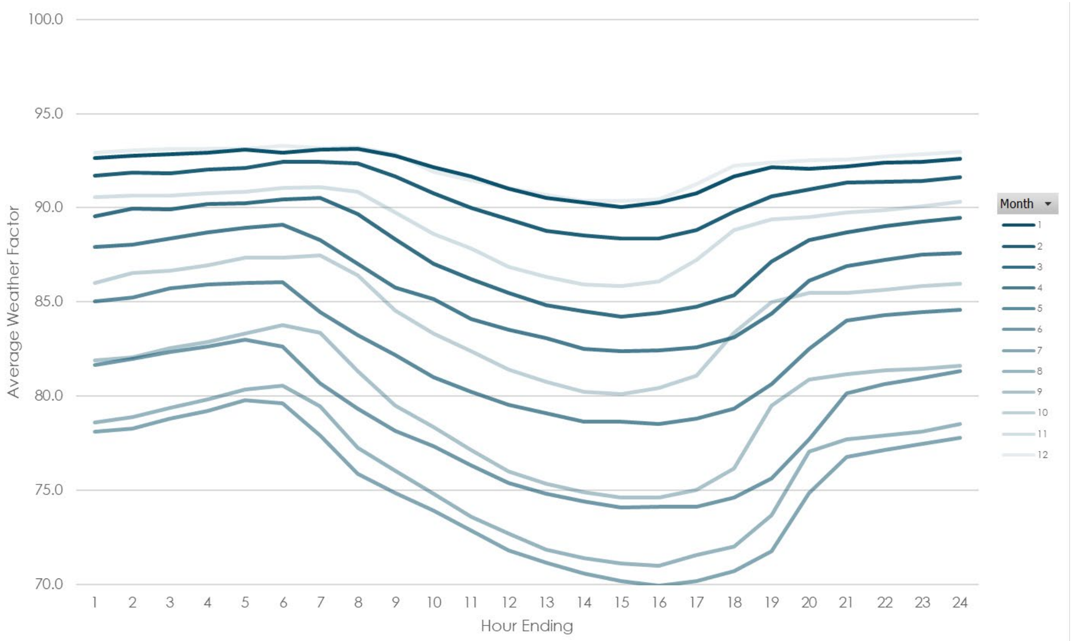
EGS Weather Stations



EGS Hourly Profile Example and Results

- As expected, hourly system output is lowest in hot summer months, with overall deration varying by location
  - **California**: roughly 75%-80% system output between 1pm and 8pm
  - **Idaho** (shown at right): output dips just below 70% at 4pm PST in July, driven by very cold rated temperatures and wider overall temperature swings between winter and summer months

Month-Hour Profile for Idaho EGS



Marginal ELCC Calculation for EGS Resources

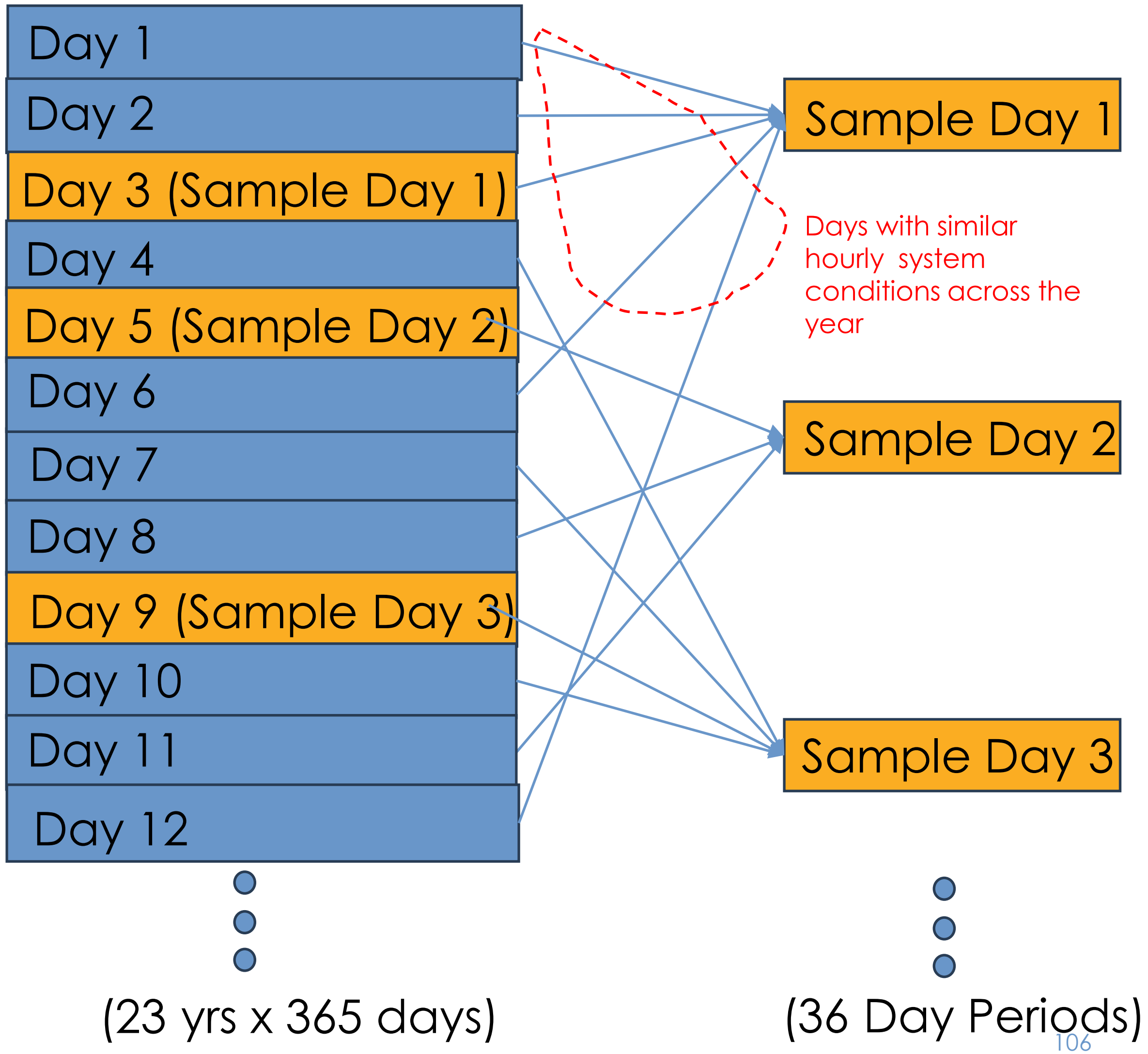
- The EGS hourly profiles are applied to each EGS resource in RESOLVE and SERVM
- In SERVM, marginal ELCC runs were performed to determine the ELCC value of each candidate resource:
  - Independently, 500 MW of EGS resource is introduced onto the system
  - A quantity of perfect capacity (PCAP) resource was then removed until the system returned to 0.1 LOLE
  - Regression was used to calculate the marginal ELCC value

EGS Unit	Average CF (%)	ELCC (%)
PGE_EGS	91%	89%
SCE_EGS	89%	84%
SDGE_EGS	88%	90%
Nevada_EGS	86%	94%
Oregon_EGS	86%	90%
Utah_EGS	84%	86%
Idaho_EGS	84%	87%

RESOLVE Representative Sample Days

Representative Day Selection Process

- RESOLVE models select sample days to represent a range of different weather conditions while managing the problem size for capacity expansion optimization
- A K-medoids clustering algorithm is used to select the sample days
    1. Takes in hourly historical data from 23 weather years (2000 to 2022):
        - Load
        - Wind and solar generation
        - Hydro energy budget
    2. Groups similar days across the historical data into one cluster (sample day)



Workflow to Determine Sample Days

Check the Correlation of Input Profiles

Selected wind and solar profiles that are more distinct and informative to be used for day clustering

Run clustering algorithm with a range of different weights for input profiles

A clustering algorithm is used to identify representative days within weather year data; different weights for load, solar, wind, and hydro profiles are tested to determine optimal weights that minimize clustering error (i.e. RMSE)

Check Performance of Sample Days

- *Energy Representation*
- *Calendar Distribution*
- *Hydro Budget*
- *Gross Load Representation*
- *Load-Resource Correlation*

RMSE: Root Mean Square Error

Criteria for "Best Performing" Sample Days

Energy Representation	**Capacity factors in sample days are within the range of expected capacity factors in historical weather years** Sample days are by design the average of clustered historical days; thus, low renewable sample days represent an *average* low renewable day instead of the lowest historical days
Calendar Distribution	**Selected sample days are distributed across all twelve months and days of the week** At least one day from each month of the year, a mix of weekend or weekdays, etc.
Hydro Budget	**Sample day profiles capture hydro year variabilities** Relying on one type of water year such as extremely low hydro year may lead to unreasonable investment decisions
Gross Load Representation	**Sample day profiles represent average expected diurnal and seasonal load patterns** Sample days do not necessarily need to capture 1-2 or 1-10 peak days, since the PRM modeled in RESOLVE is designed to determine the reliability need
Load-Resource Correlation	**Sample day profiles capture the correlation between renewable generation and load** Net load shape captures the variation in both renewables and loads

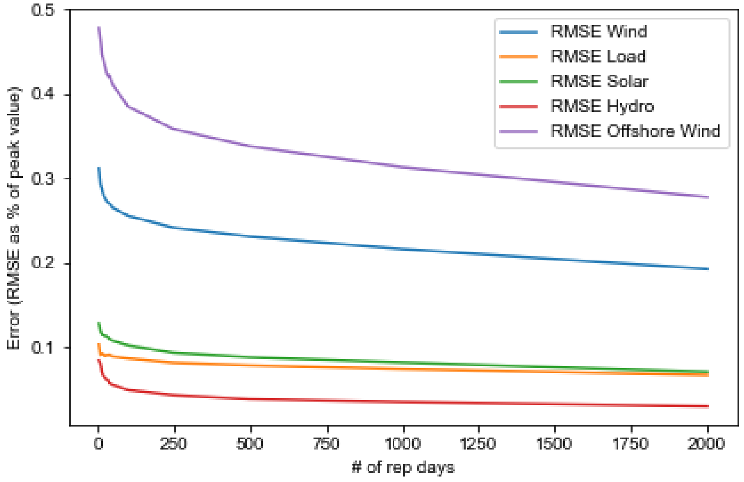
Selected 36 Sample Days

Sample Day	% of Dataset	Sample Day	% of Dataset	Sample Day	% of Dataset
1/10/06	2.3%	5/27/18	0.3%	9/22/01	3.0%
1/23/05	3.4%	6/8/11	2.3%	9/28/08	4.9%
2/26/12	2.5%	6/20/05	2.6%	10/2/05	4.0%
3/6/20	4.4%	7/23/11	2.1%	10/29/11	4.0%
4/5/21	1.7%	7/25/12	2.4%	11/8/05	3.0%
4/7/02	2.9%	7/31/05	1.5%	11/9/01	2.9%
4/11/03	3.8%	8/5/04	3.0%	11/20/03	3.9%
4/20/14	2.8%	8/6/05	2.0%	11/29/03	2.6%
5/3/19	1.7%	8/20/05	3.2%	11/30/13	4.5%
5/4/10	1.7%	8/23/22	2.1%	12/5/14	1.7%
5/8/18	3.9%	8/30/03	3.3%	12/12/14	0.3%
5/15/13	3.5%	9/7/06	3.3%	12/12/16	2.7%

High Curtailment Spring day

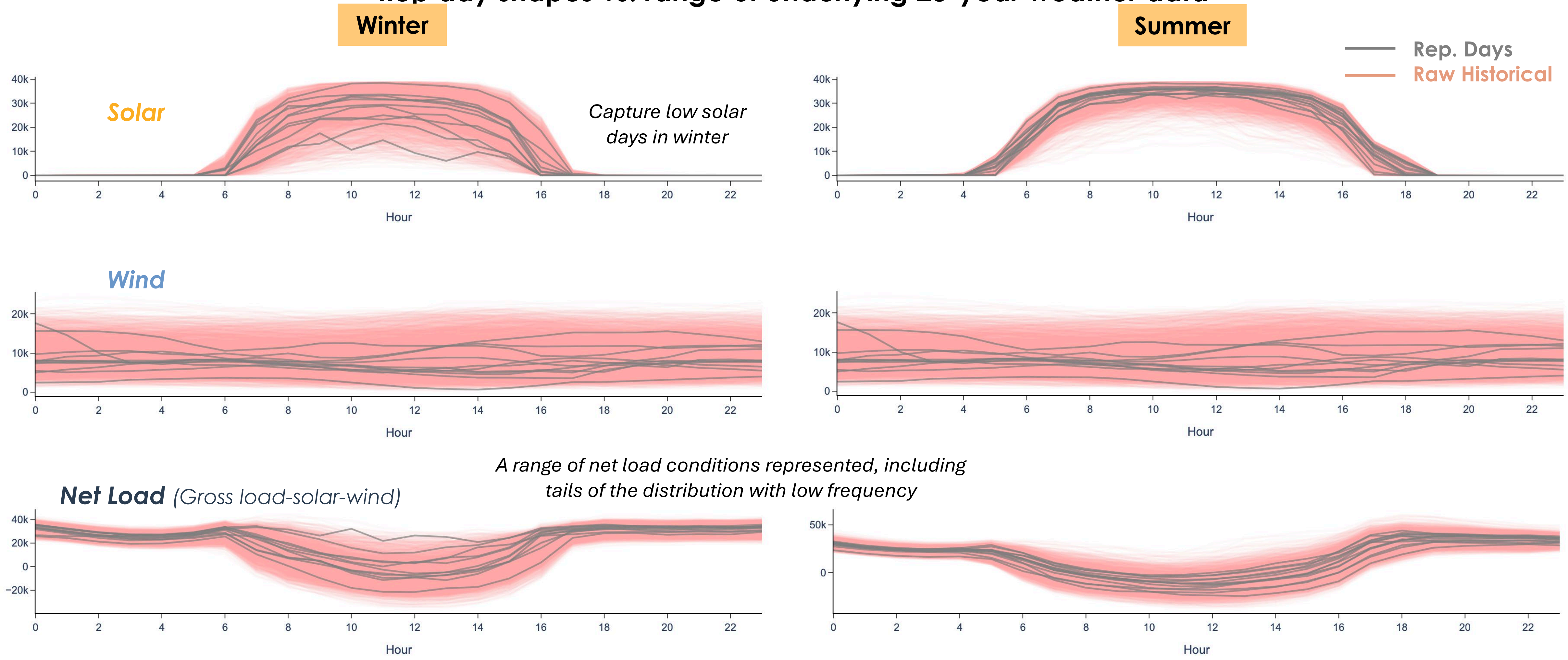
High Net Load Winter day

Selecting more than 30-40 representative days can result in very small improvement in reduced error



Selected sample days are within the range of historical weather data while capturing a range of variations

Rep day shapes vs. range of underlying 23-year weather data

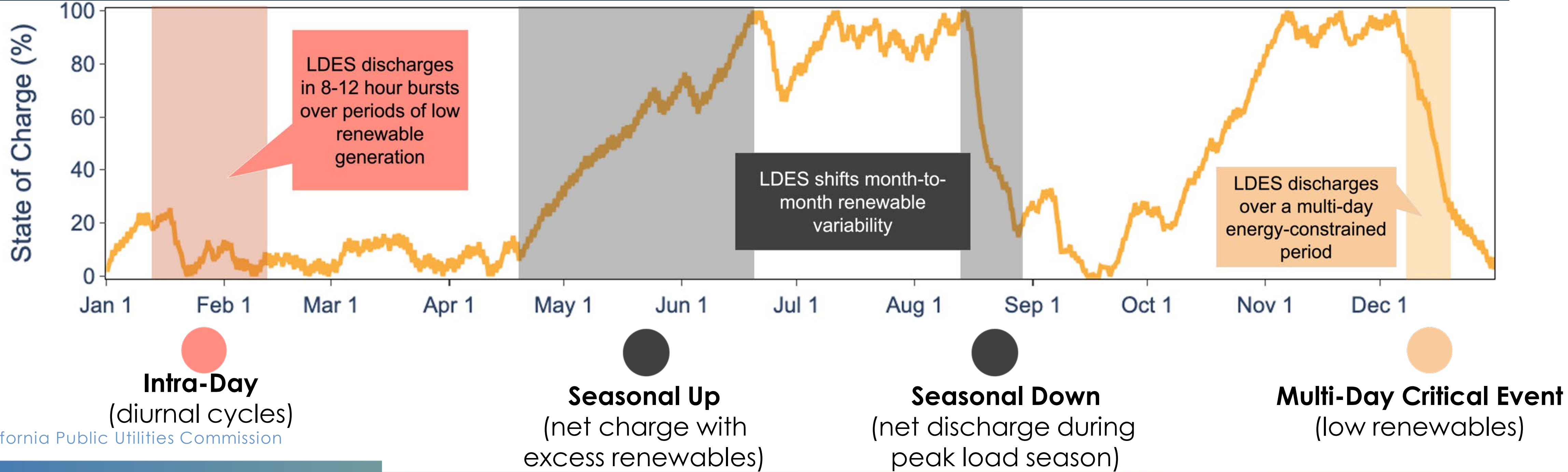


Inter-day Sharing for Long-Duration Storage

Intra- and Inter-Day Sharing for Storage Technologies in RESOLVE

- **Intra-day sharing** typically captures the diurnal storage cycles
- **Inter-day sharing** is more important for long duration energy storage (8+ hrs) and allows for:
  - Storage to charge over longer periods when excess renewables are available (from one day/month/season to another)
  - Storage to discharge across multiple days during energy-constrained conditions

Illustrative Example from 2023 CEC Long Duration Storage RESOLVE Study



Ongoing Updates to Introduce Inter-Day Sharing

Intra-Day (2022-2023 IRP Cycle)

The full 23 weather years are clustered into 36 sample days

Dispatch in each sample day is independent of other sample days

RESOLVE **optimizes storage dispatch within each sample day**, with **no net change in state of charge**

Inter-Day (2024-2026 IRP Cycle)

The full 23 weather years are clustered into 36 sample days

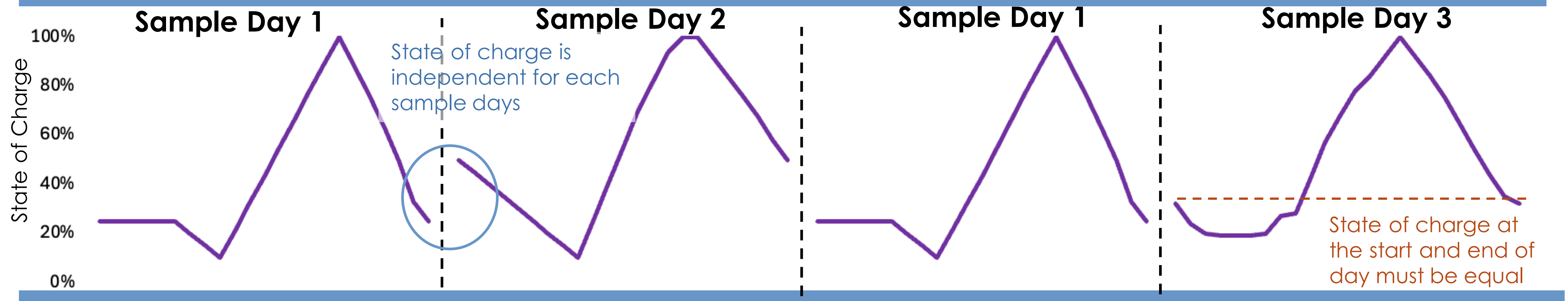
Sample days are mapped to historical days to **create annual chronology**

RESOLVE **optimizes storage dispatch across sample days,** allowing for a **net change in state of charge** on each sample day

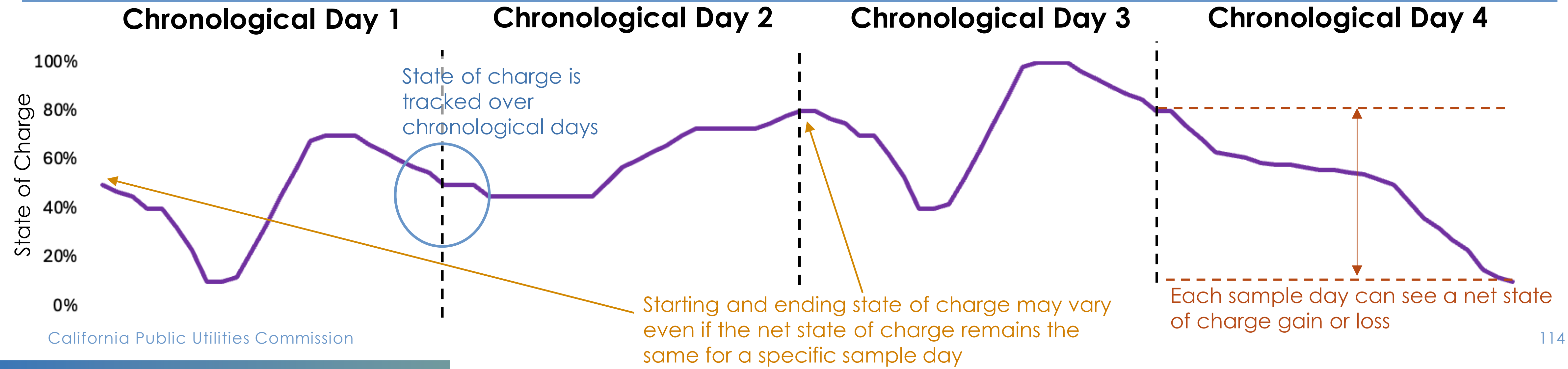
The state of charge constraint is tracked chronologically to ensure it cannot exceed 100% or go below the minimum

Illustrative RESOLVE Storage Dispatch

4 Days with Intra-Day Sharing



4 Days with Inter-Day Sharing



Notes and stakeholder Feedback on Storage Modeling

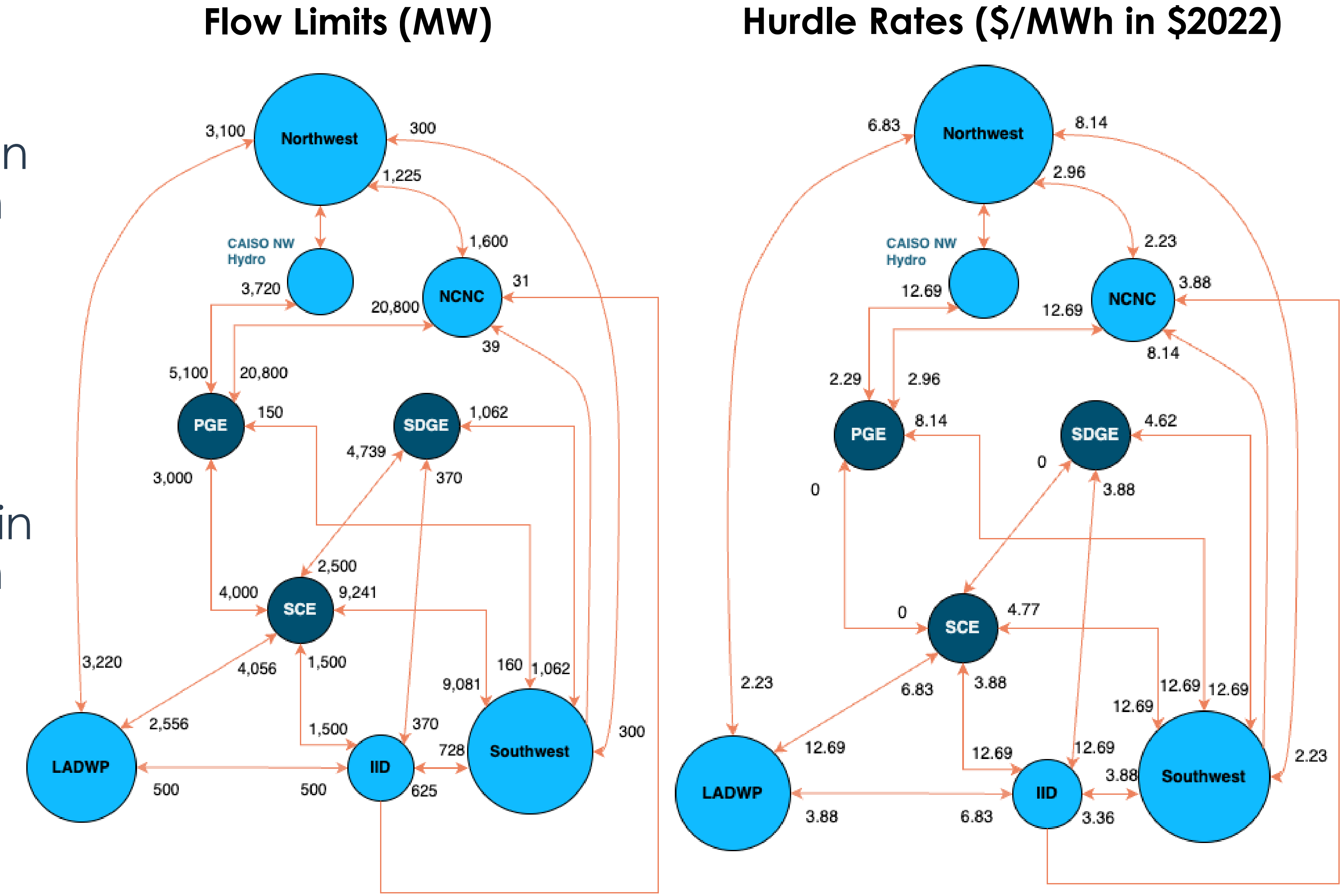
- Staff is currently performing additional analysis on the implications of inter-day sharing in RESOLVE and will evaluate the potential of including this feature in RESOLVE modeling going forward
- For the proposed storage technology options, Staff is seeking stakeholder feedback on:
  - Minimum state of charge (%)
    - Currently assume 0% for pumped hydro and 10% for all other storage technologies
  - Self-discharge rate (%/day or %/month)
    - To capture energy losses across longer period of standby operation, beyond round-trip efficiencies (RTE) which typically captures the losses during energy charging and discharge. Examples include:
      - Li-ion Battery: 2-3%/month[1]
      - Pumped Hydro Storage and CAES: 0%/day[2]
      - 12-hr LDES archetype: <0.1%/day (flow battery[1])
      - 100-hr LDES archetype: data not available for iron-air (highly chemistry-dependent, wide ranges reported for nickel-iron alkaline batteries of 20-40%/month[3] and 25%/day for Zn-air batteries[4])

1 https://onlinelibrary.wiley.com/doi/full/10.1002/cnl2.106#:~:text=By%20recharging%2C%20the%20metastable%20electron,parameters%20for%20typical%20battery%20systems.&text=Schematic%20illustration%20of%20self%2Ddischarge,characteristics%20among%20typical%20battery%20chemistry.&text=Abbreviations:%20SSD%2C%20suitable%20storage%20duration,%2C%20sodium%2Dnickel%20chloride%20batteries.;2 https://www.sciencedirect.com/science/article/pii/S2352152X2300035X;3 https://www.sciencedirect.com/science/article/pii/S2590049821000266#bib34;4 https://www.sciencedirect.com/science/article/abs/pii/S1226086X19301558

RESOLVE Transmission Topology

Transmission Path Ratings and Hurdle Rates

- Transmission flow limits in RESOLVE are the sum of flow limits between individual BAAs in SERVM, which are derived from nodal flow ratings from the WECC 2032 ADS
- Transmission hurdle rates in RESOLVE are the capacity-weighted average of hurdle rates between individual BAAs in SERVM, which are derived from nodal flow ratings from the WECC 2032 ADS
- Paths within CAISO have a $0 hurdle rate



Transmission Expansion Between CAISO Zones

- While most transmission path ratings remain static across the modeling horizon, upgrades are available which can expand transmission paths within CAISO
- **Merging of SCE and SDGE zones[1]:** SDGE<>SCE path has flow limits through the end of 2033, but starting in 2034, path limits are eliminated through planned transmission upgrades, allowing a single zone treatment of the SCE and SDGE areas
- **RESOLVE-Selectable Upgrade(s) of PGE<>SCE Path Rating:** Expansions of the existing interconnection between PGE<>SCE, particularly in the SCE>PGE direction, are modeled as upgrades that RESOLVE can select in three tranches, each with increasing costs. Upgrades include both an expansion of Path 26 between PGE and SCE and additional upgrades necessary to deliver energy from resources located in Southern California to PGE load centers.

1 2024 TPD Whitepaper and Attachment A

RESOLVE PGE<>SCE Transmission Upgrade Tranches

- RESOLVE may select each tranche sequentially, if they are found to be cost optimal, on top of the existing PGE<>SCE transmission capability (3,000 MW from SCE to PGE, 4,000 MW from PGE to SCE)
- Staff solicits stakeholder feedback on the first available year to be used for each tranche

Tranche #	Incremental Upgrade (MW)	Total Upgrade (MW)	Total Path Rating (MW)	Cost of Tranche ($)	Levelized Cost ($/kW-yr)[1]	First Available Year	Description	Source
Tranche 1	1,000	1,000	4,000 (SCE to PGE) 5,000 (PGE to SCE)	$0.6 B	$50	**2033-2034**	New Windhub to Midway 500 kV line	CAISO 22-23 TPP[3]
Tranche 2	1,500	2,500	5,500 (SCE to PGE) 6,500 (PGE to SCE)	$2.5 B	$128	**2035-2037**	New Whirlwind to Midway 500 kV line Path 15 upgrade (Alternative 6 from the 23-24 TPP Congestion Economic Study[2])	CAISO 23-24 TPP[2] Per-Unit cost guide[4]
Tranche 3	3,000	5,500	8,500 (SCE to PGE) 9,500 (PGE to SCE)	$6.0 B	$156	**2037-2039**	New Lugo to Vincent 500 kV line Two new Vincent to Midway 500 kV lines Path 15 upgrade (Alternative 8 from the 23-24 TPP Congestion Economic Study[2])	CAISO 23-24 TPP[2] Per-Unit cost guide[4]

1 Real 2022$; assumes a 7.80% CRF; 2 https://www.caiso.com/documents/appendix-g-board-approved-2023-2024-transmission-plan.pdf;
3 2022-2023 Transmission Plan Appendix F; 4 https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook-2023-2024

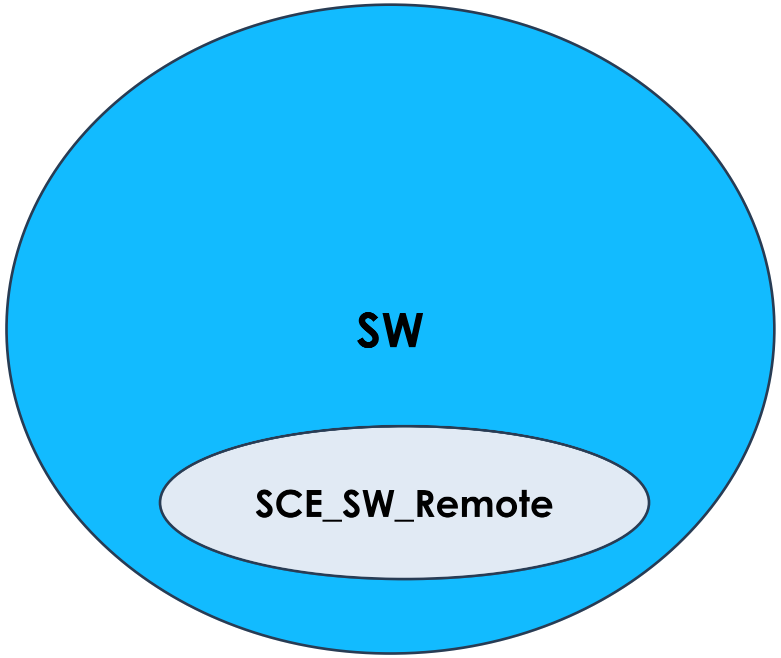
Remote Generators in RESOLVE

- Remote generators are units that are physically located outside of the region they are contracted to serve
- Starting in this cycle, RESOLVE models remote generators in "remote zones" outside of CAISO to better align with SERVM and account for their transmission usage
  - This is similar to how CAISO_NW_Hydro has been modeled in a separate zone going back multiple cycles
  - Only baseline resources are included in remote zones; there are no candidate resources for remote zones

Remote Generators in 2023 IRP	Remote Generators in 2025 IRP
1. Deliver energy to serve CAISO load (including GHG-free energy) 2. Do not contribute firm RA to CAISO; modeled within the 4 GW import RA limit (discussed in Reliability section) 3. **Modeled as in-CAISO resources in RESOLVE**	1. Deliver energy to serve CAISO load (including GHG-free energy) 2. Do not contribute firm RA to CAISO; modeled within the 4 GW import RA limit 3. **Modeled as outside of CAISO, sharing transmission into CAISO with unspecified imports**

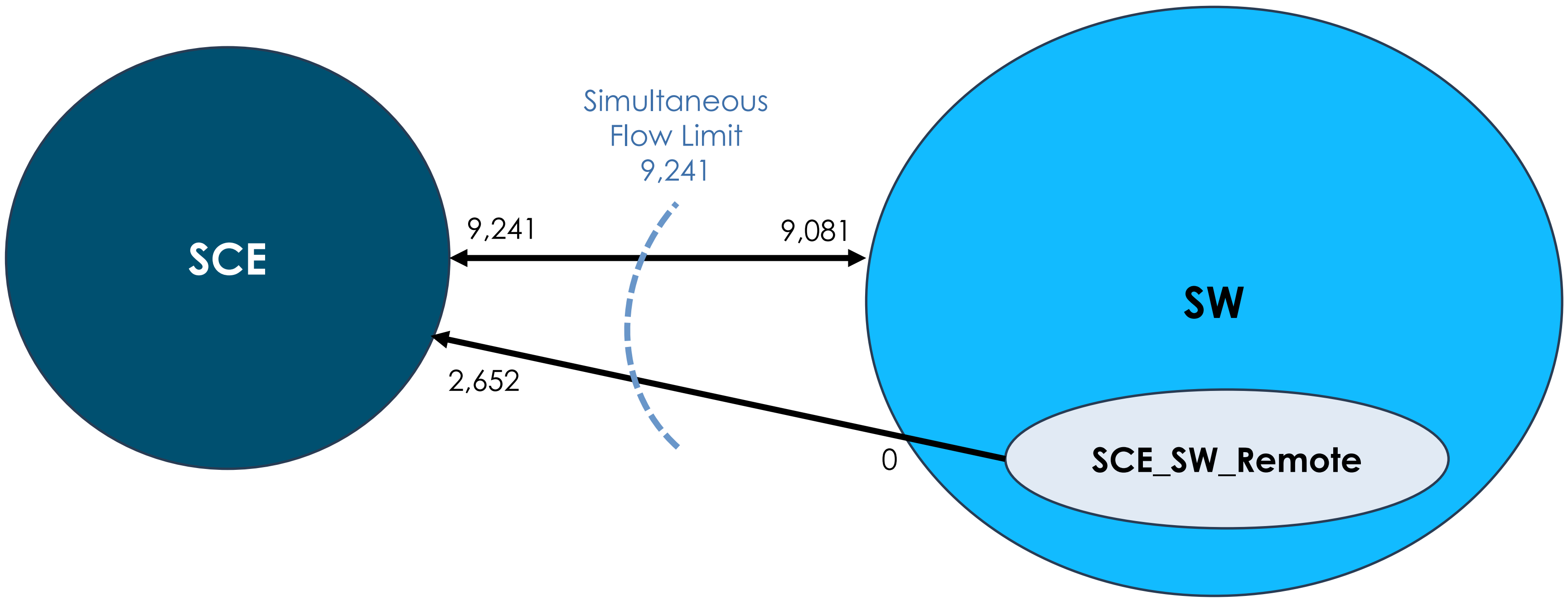
Example RESOLVE Remote Generator Topology

- **SW Zone**:
  - Resources both located in and contracted to SW BAAs
  - All loads associated with SW BAAs
  - Bidirectional transmission ties to other zones, with associated hurdle rates
- **SCE_SW_Remote Zone**:
  - Resources located in SW, but contracted to deliver energy to SCE
  - No load (forces energy to be transmitted to SCE)
  - Single-direction transmission to SCE, with $0 hurdle rate to discourage curtailment of non-emitting remote generators



In the RESOLVE Results Viewer, remote generator capacity and generation will be aggregated into their contracted zone (SCE in the above example) for simplicity.

Example RESOLVE Remote Generator Transmission



2,652 MW of resources in SCE_SW_Remote

Transmission Path	Forward Flow Limit (MW) – to SCE	Reverse Flow Limit (MW) – from SCE
SW_to_SCE	9,241	9,081
SCE_SW_Remote_to_SCE	2,652	0
Simultaneous Flow Constraint	**9,241**	N/A

CAISO Specified Imports

- Specified imports, like remote generators, are physically located outside of the region they are contracted to serve; unlike remote generators, they have firm RA contributions
- In SERVM and RESOLVE, specified imports are "moved" into the region they are contracted to, with firm RA & transmission
- Historically, four specified imports have been modeled in CAISO: Hoover, Intermountain, Palo Verde, and Sutter
- Starting in this cycle, two in-development units have been added as specified imports to reflect their anticipated future RA contributions:
    - SunZia Wind (new firm transmission operated by CAISO)
    - Cape Station Geothermal (MTR contract)
    - The firm RA status of these units will be reevaluated in future input updates as they progress towards operations

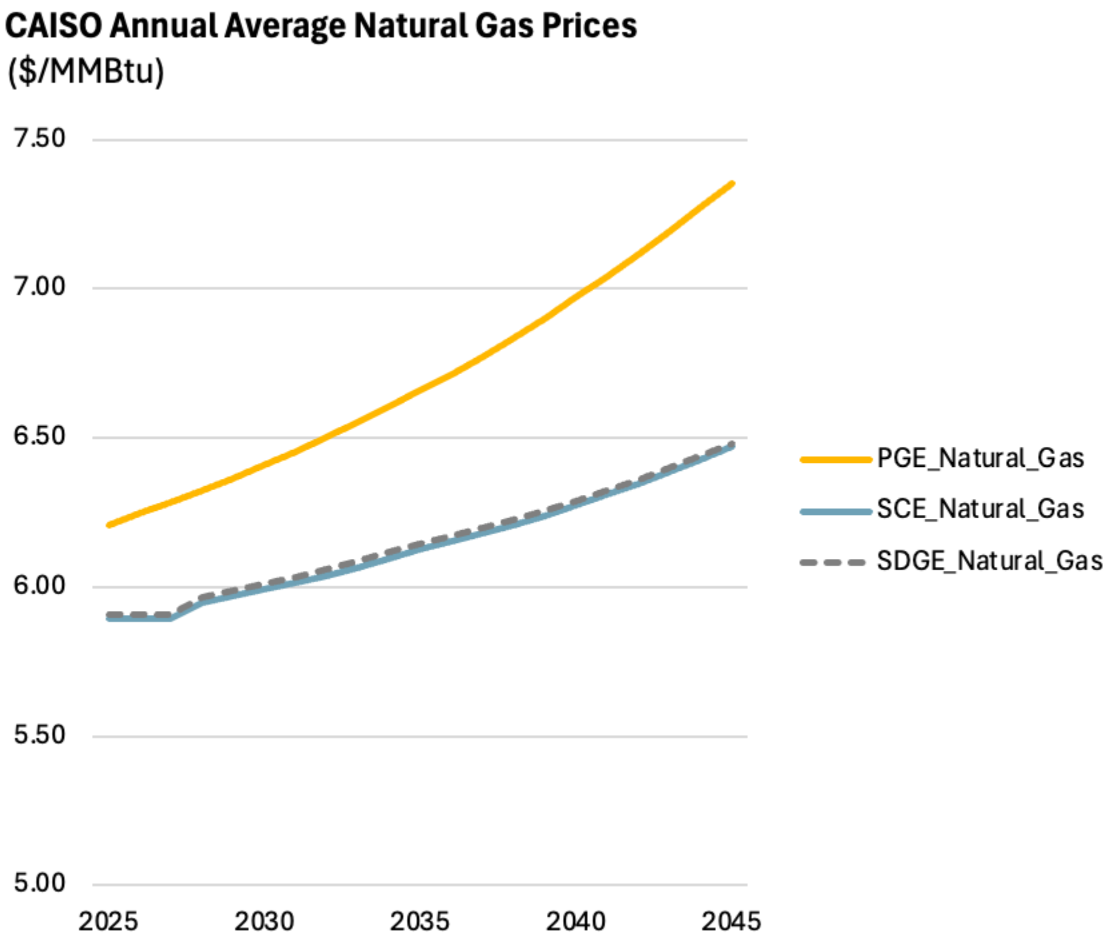
Treatment of Out-of-State Candidate Resources

- Consistent with previous IRP cycles, candidate resources that are located outside of the CAISO footprint are also modeled as in-CAISO, similar to the specified imports
- All candidate resources selected by RESOLVE are assumed to be **contracted to CAISO in full**, and have **new, firm transmission** to deliver both energy and RA to CAISO
- Out-of-state candidate resources are <u>not</u> included in:
  - The 4 GW unspecified import limit for RA (discussed in Reliability section)
  - Simultaneous flow constraints into CAISO and CA

RESOLVE Zonal Fuel Prices

Improved Fuel Price Granularity in RESOLVE

- Starting in this cycle, RESOLVE represents gas and coal price differences between the California zones, rather than having a single California price
  - The IEPR 2023 NAMGas model is the source of forecasted natural gas prices throughout WECC, the same as the previous cycle
- Uranium and Biomass price inputs remain the same as the 2023 I&A and do not vary by zone
  - Uranium: $0.71/MMBtu (from EIA Annual Energy Outlook[1])
  - Biomass/Biogas: $15/MMBtu (developed by NLR[2])



1 https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2023&cases=ref2023&sourcekey=0
2 https://www.energy.gov/sites/default/files/2018/11/f57/robi-biomass.pdf
All costs in real 2022$

Gas Retention Costs

Background and Motivation for Updates

- RESOLVE optimizes whether to economically retain or not retain baseline natural gas capacity in the CAISO system, weighing the fixed O&M cost of these units against their contribution to resource adequacy (RA)
- For multiple IRP cycles, Fixed Operations and Maintenance (FO&M) costs derived from the CEC[1] have been used for existing gas, held constant over the modeling horizon
- Stakeholders and staff have raised concerns that the gas FO&M cost input in RESOLVE is too low, which may cause RESOLVE to overestimate the amount of gas that is economic to retain
  - To continue operating, thermal units may need to pay increasing FO&M or repower at a certain age

1 CEC Cost of New Generation Report: https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-005.pdf; costs in real 2022$

Feedback on the Draft I&A

- During the Draft Inputs and Assumptions Workshop, staff proposed updated inputs for gas retention costs:
  - The Fixed O&M of baseline gas would increase over time
  - At a specific age (40 years), RESOLVE would have the option to repower gas capacity; repowering would have increased the cost of existing gas, with improvements in operational attributes
- Staff have simplified the modeling of gas retention costs in RESOLVE in response to data gaps and stakeholder feedback
  - Multiple stakeholders opposed adding a distinct repowering decision to RESOLVE
  - Other stakeholders advocated for cost increases starting at 30 years of age due to increased cycling, and escalating to costs similar to recent RA prices; the updated inputs are closely aligned with these suggestions

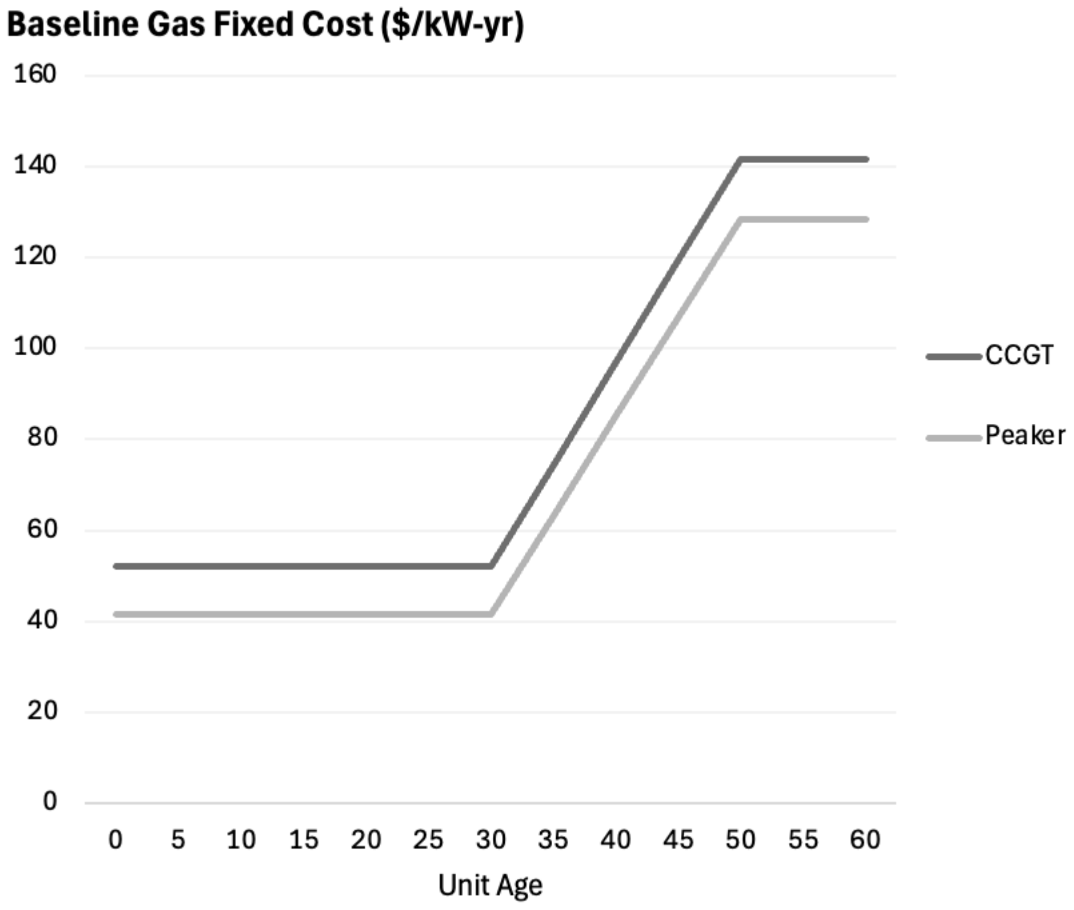
Changes from Draft to Final I&A

Draft I&A	Final I&A
Fixed cost increases at a (tentative) trajectory of 1%/year starting at the age of 40 years	Fixed costs increases linearly between the ages of 30 and 50 years, rising from the current cost assumption to the cost of repowering
A distinct repowering option available for RESOLVE to optimally select at the age of 40 years	No distinct repower decision is modeled since fixed cost trajectory now ends at the cost of repowering
Cost of repowering based on brownfield costs for new gas	Unchanged

Note: Under the previous approach, the repowering option was unlikely to be cost-effective in any case due to the low rate (1%) of fixed cost increase

RESOLVE Gas Retention Costs

- First 30 years of life use the gas fixed O&M costs from previous cycles, derived from the CEC[1]
- From the age of 50 years, baseline gas unit costs are equal to the cost of repowering (brownfield costs, as a % of greenfield (new) costs), plus the Fixed O&M of a new unit
  - CCGT: Brownfield costs 90% of greenfield
  - Peaker: Brownfield costs 86% of greenfield
- Linear increase from age 30 to 50



1 CEC Cost of New Generation Report: https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-005.pdf; costs in real 2022$

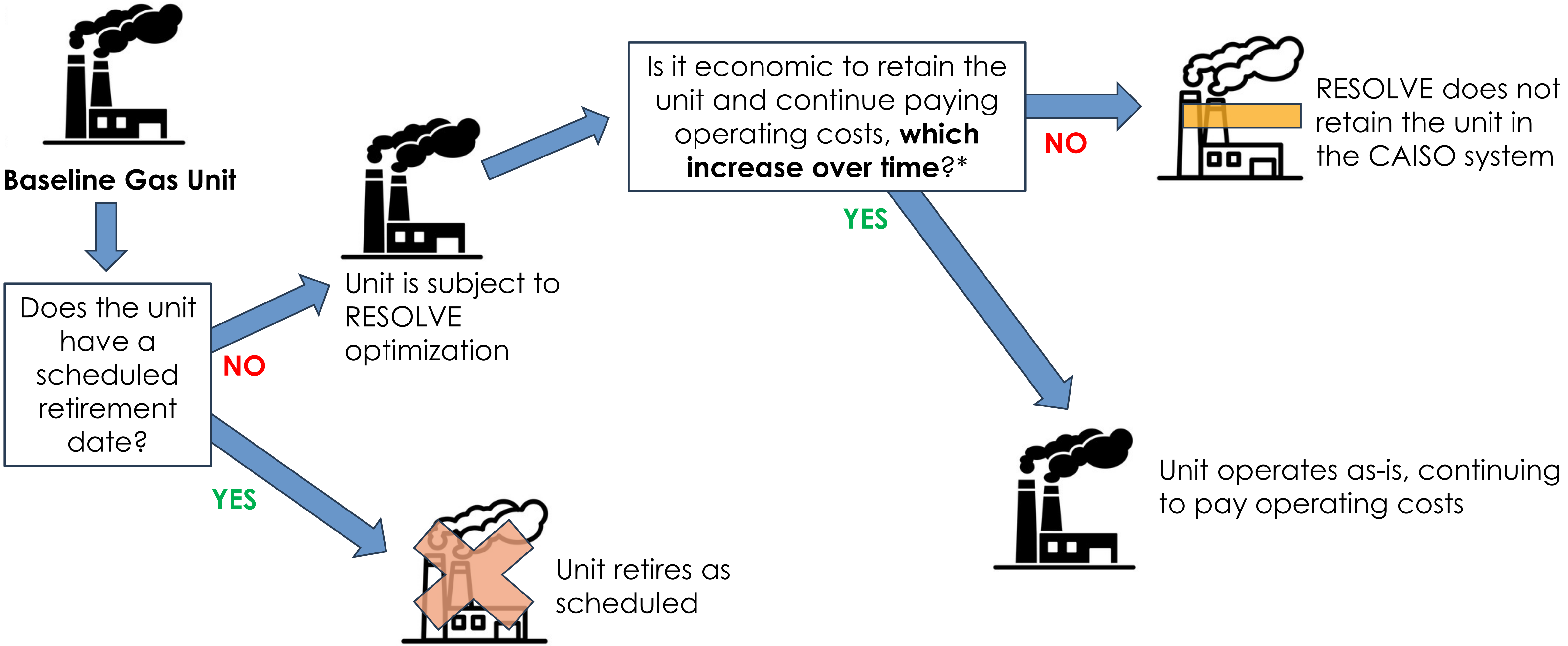
Age-Based RESOLVE Gas Tranches

- To best implement the fixed cost trajectory, RESOLVE gas tranches will be age-based rather than efficiency-based
  - Stakeholders have advocated for this in past cycles
  - This is likely to have only a small impact of gas dispatch in RESOLVE as the majority of CCGTs (which make up most of the RESOLVE-dispatched gas) have similar heat rates

Gas Tranche	Range of Online Years	Total CAISO Capacity
CCGT1/Peaker1	2010 or later	CCGT1: 5,551 MW Peaker1: 4,012 MW
CCGT2/Peaker2	2000-2009	CCGT2: 11,239 MW Peaker2: 2,825 MW
CCGT3/Peaker3	Before 2000	CCGT3: 448 MW Peaker3: 1,136 MW

Note: remote gas generators (physically located outside of CAISO with no firm RA) excluded from tranches

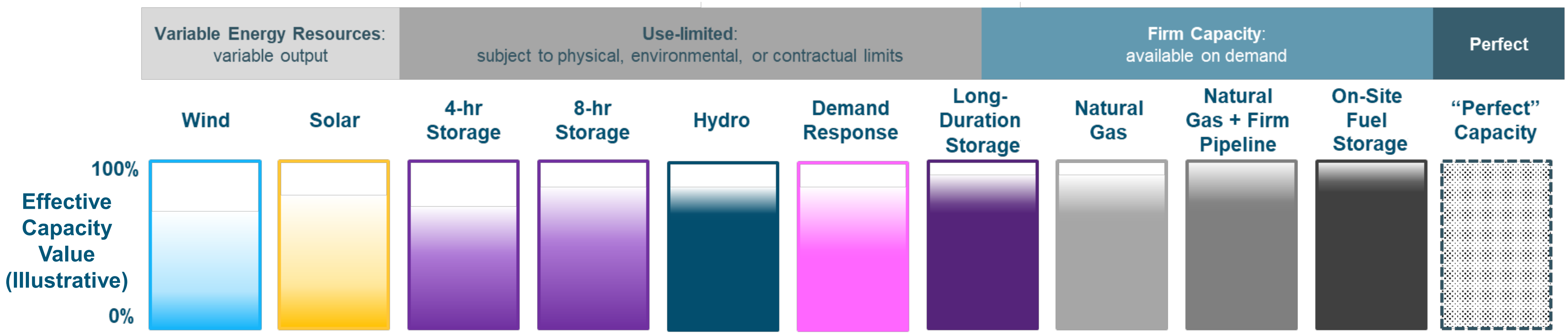
RESOLVE Decisions for Natural Gas Capacity



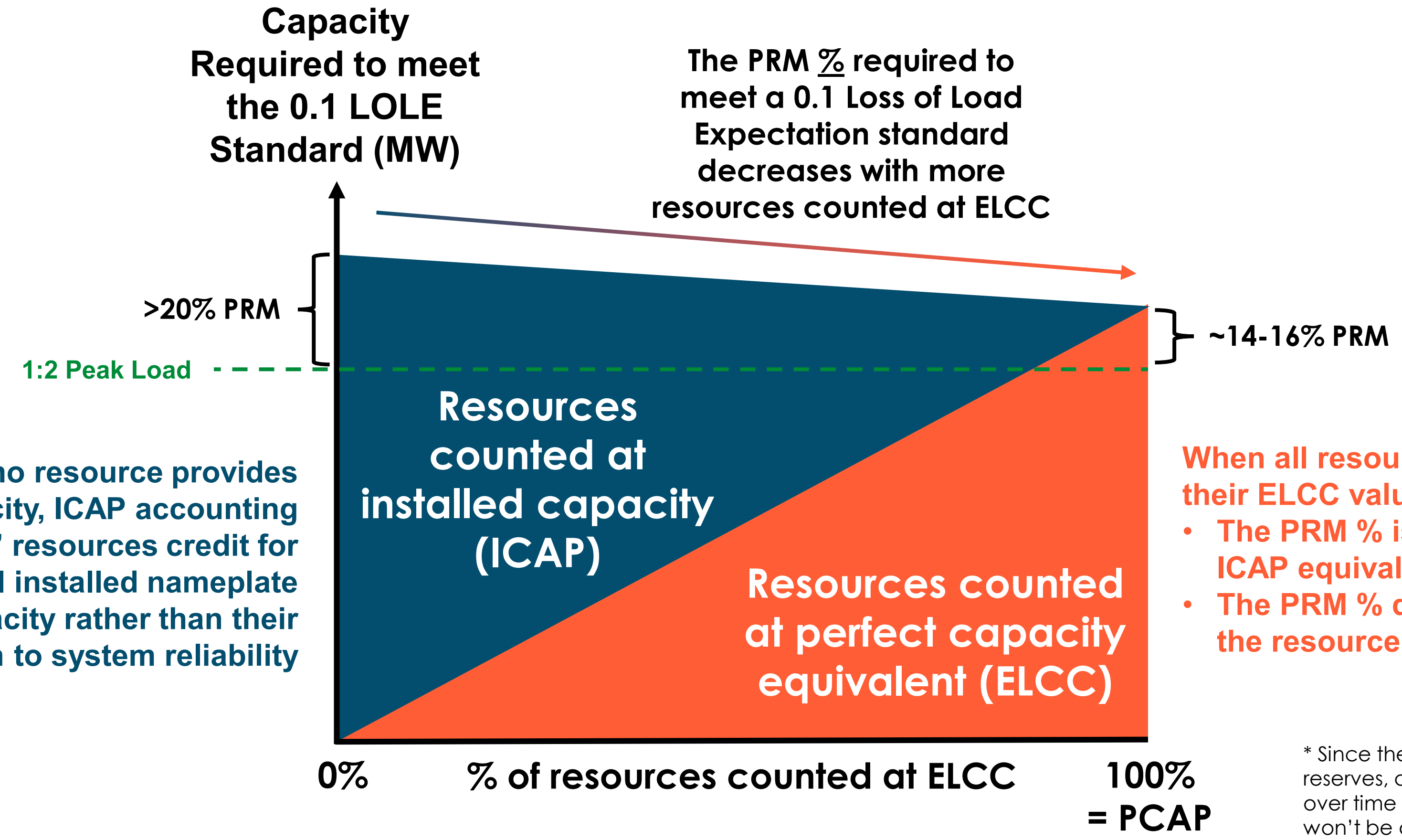
*RESOLVE must also meet the local capacity retention requirement while making non-retention decisions

PRM and ELCC

No Resource Provides Perfect Capacity



PCAP PRM provides a more durable definition of total reliability need



Even though no resource provides perfect capacity, ICAP accounting gives "firm" resources credit for their full installed nameplate capacity rather than their contribution to system reliability

When all resources are counted at their ELCC value:

- The PRM % is lower than its ICAP equivalent
- The PRM % does not change as the resource portfolio evolves*

* Since the PCAP PRM % is a function of operating reserves, and load variability, the % may change over time if these inputs change but the percentage won't be dependent on the resource portfolio.

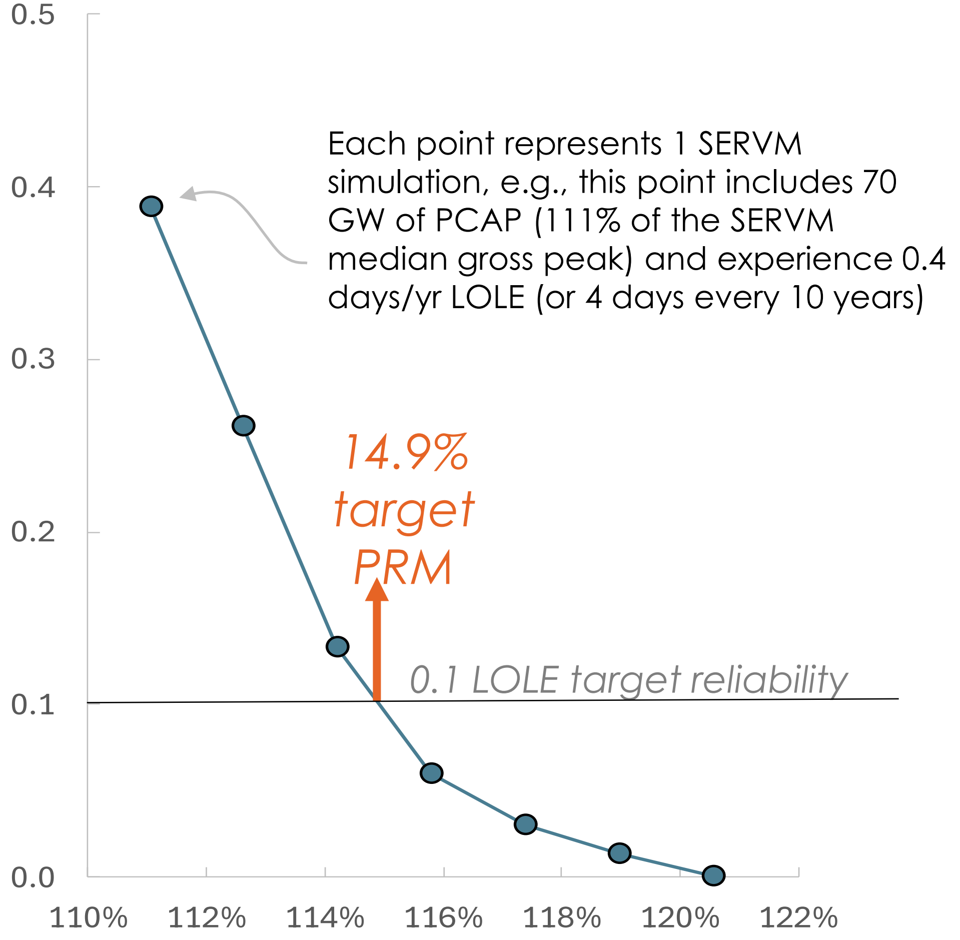
CAISO PCAP Planning Reserve Margin Results

Target PRM results were calculated for four years in the planning horizon: 2026, 2030, 2035, 2040; the PRM target for interim years is interpolated

Target PRM Results

	2026	2030	2035	2040
PCAP added to achieve 0.1 LOLE, *MW*	60,057	63,061	72,412	78,557
SERVM Median Gross Peak*, *MW*	51,958	55,053	63,042	68,872
Target PRM, *% Peak*	**15.6%**	**14.5%**	**14.9%**	**14.1%**

Loss of load expectation (days/yr in 2035)



Total Perfect Capacity Need, *% of SERVM Gross Peak*

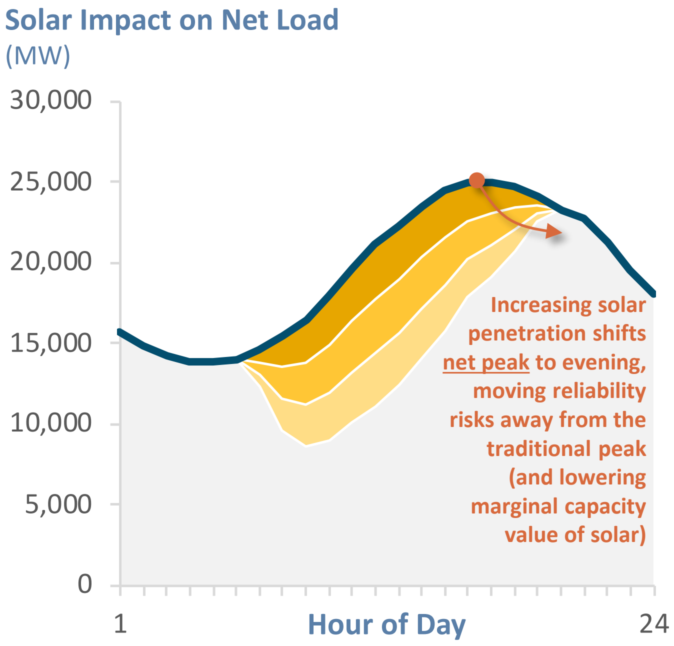
*The PCAP PRM is measured relative to gross peak (managed peak + BTM PV) as BTM PV is modeled as a resource in RESOLVE. SERVM loads are calibrated to match the 2023 IEPR's managed peak (after all load modifiers), which results in some divergence from the IEPR's gross peak in SERVM, hence the use of the SERVM gross peak that results from this calibration to IEPR managed peak.

Approach to Reliability Resource Contributions

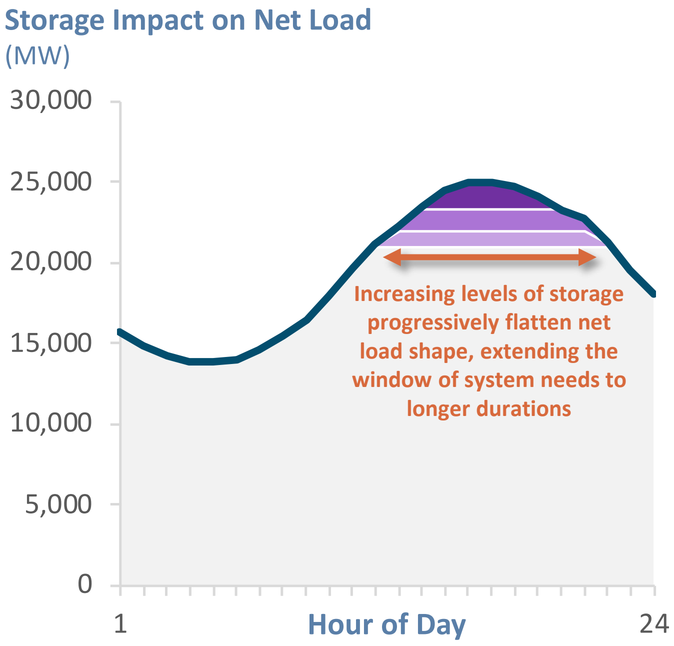
- This IRP cycle will continue the "ELCC for all resources" approach used in the prior cycle, which has the following key benefits:
  - All resource types are counted on a level playing field (of ELCC MW), which consistently recognizes their availability and use limitations
  - The reliability need (i.e., PRM) is not portfolio dependent, creating a stable PRM across a wide range of portfolios studied
  - This approach – in combination with iterative checks with SERVM – has proven in prior cycles to produce reliable portfolios
- The base year for loads and resources for ELCC studies in this cycle was updated from 2030 to 2035, which captures continued electrification load growth and additional solar + wind resource interactions
- A key update to this approach for this cycle was adding an additional 8-hr storage dimension to the solar and storage surface – creating a 3-D surface – in recognition of the importance of valuing interactive effects between 4-hr and 8-hr storage
  - 12-hr, 24-hr, and 100-hr storage now captured via multipliers to the 8-hr dimension

ELCC captures complex dynamics resulting from increasing penetrations of variable & energy limited resources

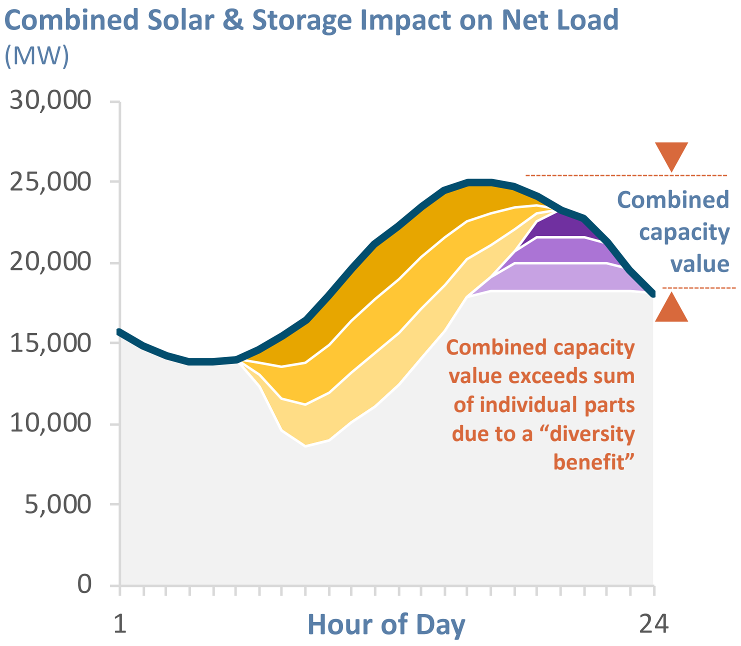
"<u>Variable</u>" resources shift reliability risks to different times of day



"<u>Energy-limited</u>" resources spread reliability risks across longer periods



A <u>portfolio</u> of resources exhibit complex interactive effects, where the whole may exceed the sum of its parts



The ELCC approach inherently captures both **<u>capacity</u>** & **<u>energy</u>** adequacy

Summary of ELCC Methodology by Resource Type

Existing resource sequential ELCC runs establish static ELCCs

Thermal
Includes CC, CT, ICE, Cogen, Bio, Geo, Nuclear;
Single thermal ELCC calculated;
Resource class-level ELCCs allocated based on relative EFOR;
Bio/geo/cogen also de-rated per current NQC derates

Hydro

Pumped Hydro Storage (Existing)

Demand Response (Existing)

Imports
Modeled at 4 GW; Interactions between imports and solar/storage allocated to the solar + storage surface

Solar + Storage
3D ELCC surface (solar, 4-hr storage, 8-hr storage);
Longer duration storage (12-hr, 24-hr, 100-hr) and new DR represented as multipliers to 8-hr storage dimension;
Runs with and without rest of the fleet inform allocation of interactive effects between other resources and the surface

Wind
3 wind curves (CA onshore, out-of-state wind, offshore wind)

New clean non-firm resources captured via dynamic curves + surfaces

Notes: ELCCs are parameterized using 2035 loads and resources; Roundtrip testing between RESOLVE + SERVM will inform adjustments to RESOLVE inputs for additional interactive effects in other years / portfolios than those studied in these ELCC studies

Existing Thermal, Hydro, PHS, and DR ELCC Methodology

- Thermal ELCCs are derived through the following steps:
  1. Perform a "first-in" ELCC % calculation of the combined thermal fleet in SERVM
  2. Calculate a capacity-weighted average EFORd for the thermal fleet (8.35%)
  3. Calculate ELCCs for each technology by scaling up their EFORd% de-rate such that the sum of the class-level ELCCs equal the total calculated thermal fleet ELCC
     - This is calculated as: 1- (technology EFORd% * (fleetwide ELCC %/fleetwide average EFORd%))
  4. An additional adjustments for biomass, biogas, cogen (CHP), and geothermal to account for monthly capacity availability derates (per existing RA program nameplate vs. NQCs)
- Hydro, baseline pumped hydro, and baseline demand response (+ pumping load) ELCCs calculated via sequential ELCC runs above the thermal fleet (hydro "second-in", baseline pumped hydro "third-in", and baseline demand response + pumping loads "fourth-in")
- This method of sequencing the ELCCs for existing resources ensures correct accounting of interactive effects between resource classes

Thermal + Existing Hydro/PHS/DR ELCC Results

Resource Class	EFORd (Equivalent Forced Outage Rate Demand)	UCAP (1-EFORd) (% of Nameplate)	ELCC for RESOLVE (% of Nameplate)	ELCC for RESOLVE after NQC Adjustment (% of Nameplate)
Biogas	1.2%	98.8%	98.6%	72.9%
Biomass	3.7%	96.3%	95.8%	75.5%
Combined Cycle	7.2%	92.8%	92.0%	
Combined Heat and Power (CHP)	4.1%	95.9%	95.4%	70.2%
Combustion Turbine (Peaker)	17.0%	83.0%	80.9%	
Geothermal	0.9%	99.1%	99.0%	94.6%
Nuclear	0.0%	100%	100%	
Reciprocating Engine	3.3%	96.7%	96.3%	
Existing DR + Pumping Loads			97.0%	60.5%
Hydro			55.8%	
Existing Pumped Hydro Storage			100%	

Workflow for using ELCC curve or surface in planning

1. LOLE model (SERVM)

   Calculate ELCC of combinations of energy-limited resources over a wide range of installed capacities

2. Linear equations

   Convert portfolio ELCC values at a range of penetrations into linear equations for marginal and total ELCC

3. Capacity Expansion

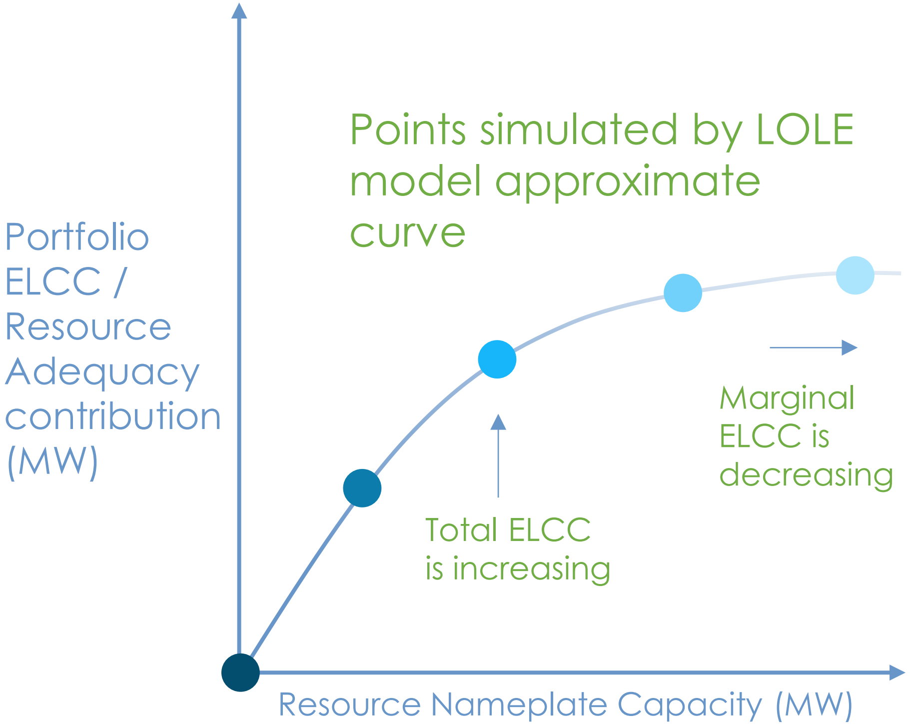
   Implement curve or surface equations in capacity expansion model, create least-cost portfolios

4. Reliability Check

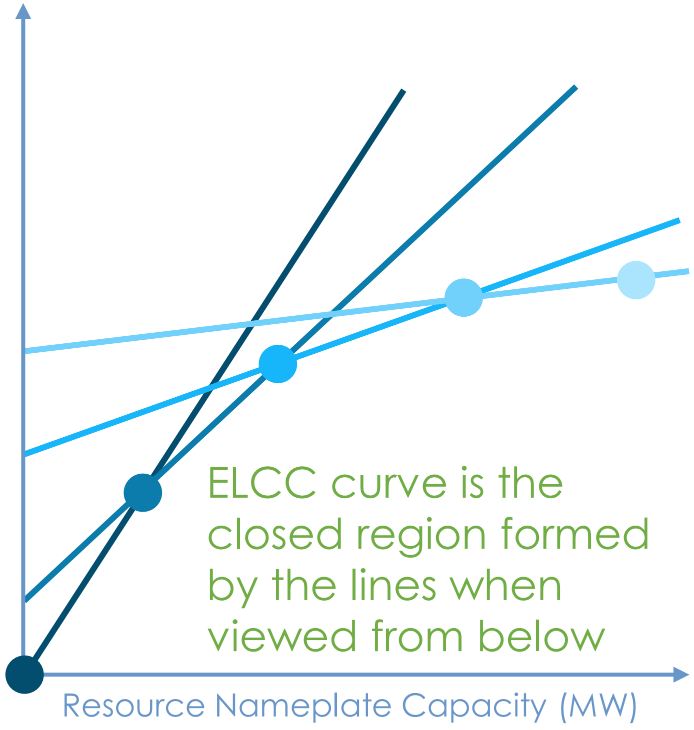
   Check reliability using LOLE model, adjusting if any issues are found

Building an ELCC curve in one dimension

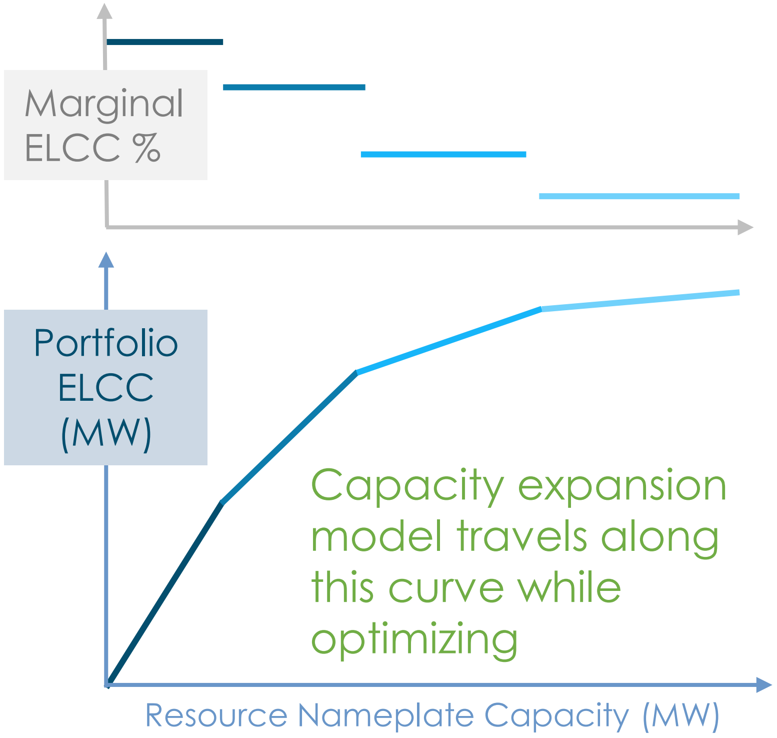
1 Calculate ELCC at Different Levels of Penetration



2 Linear equations approximate "true" ELCC curve

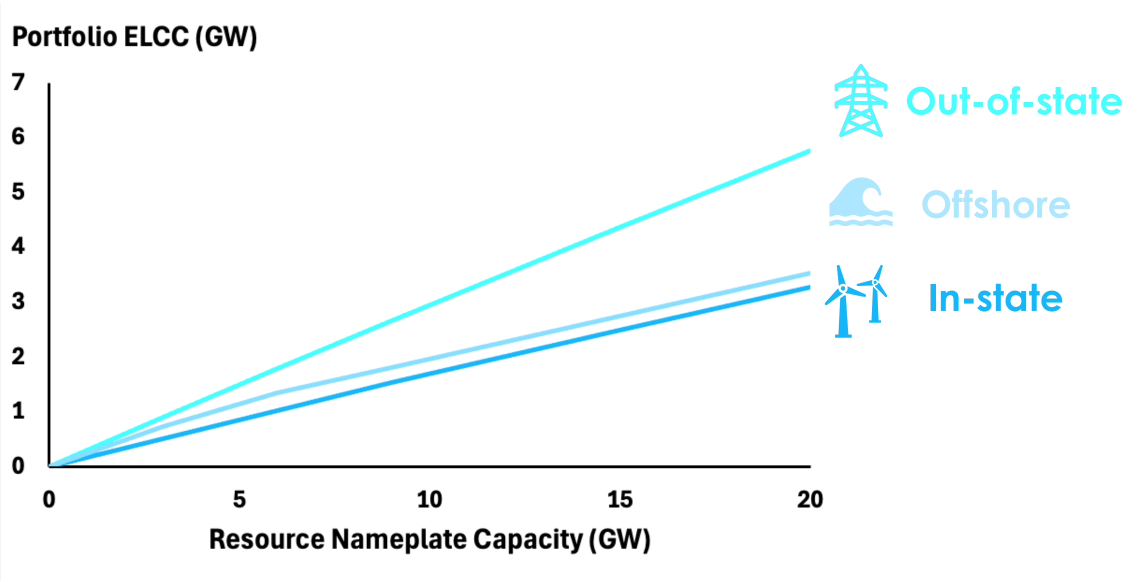


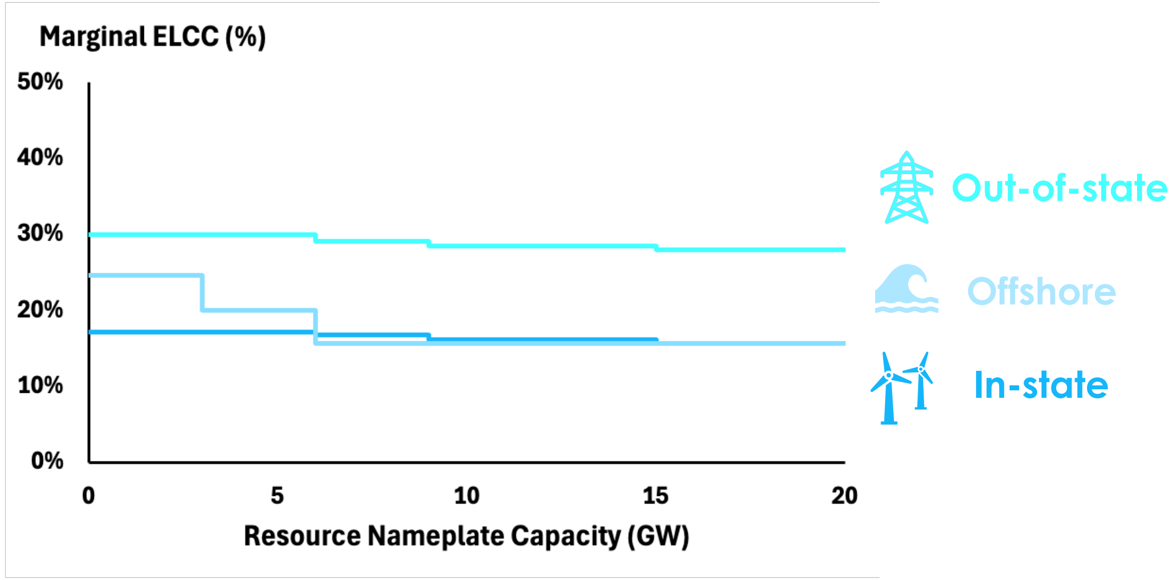
3 Implement in capacity expansion model



Wind ELCC Results

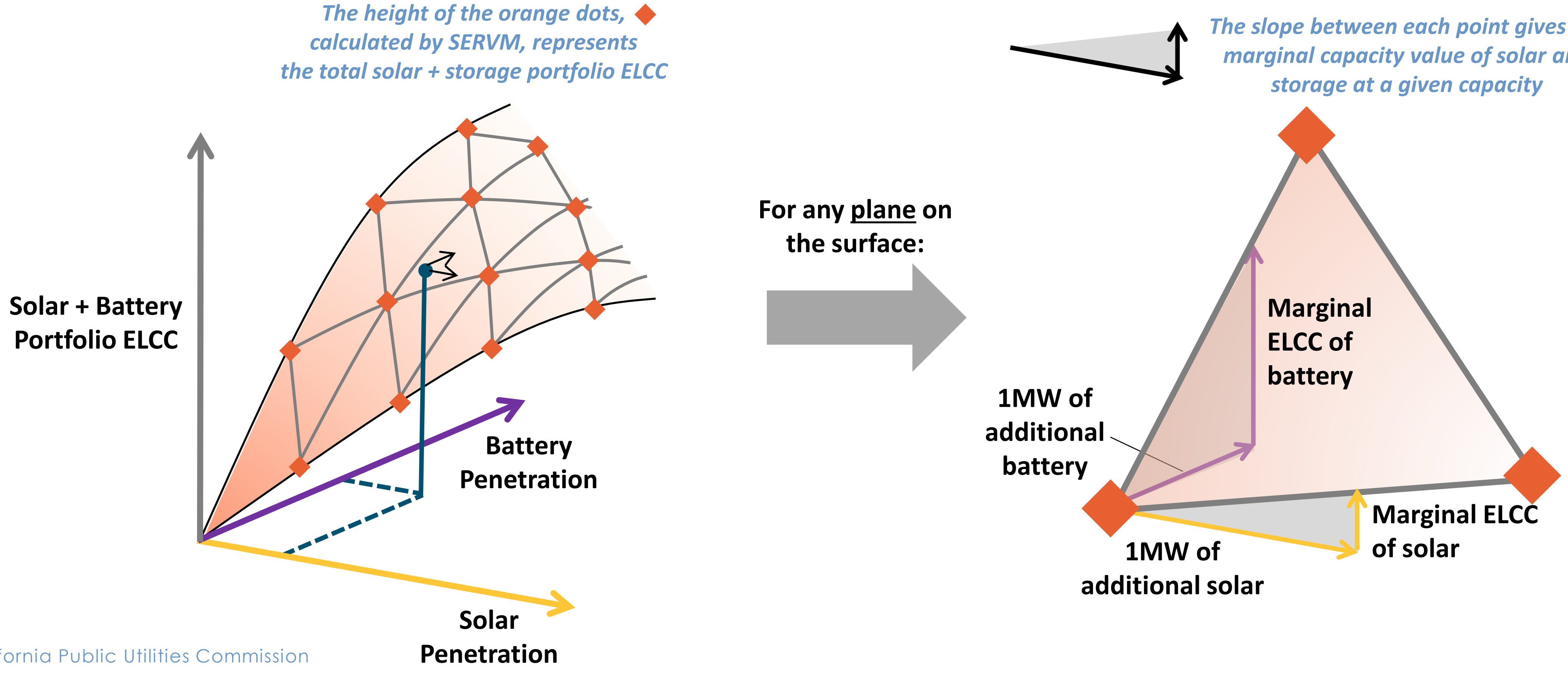
- Wind ELCC approach is the same as the last IRP cycle, updated for 2035 loads + resources and the latest CPUC wind output shapes
  - 3 curves are developed for:
    1. In-state wind
    2. Out-of-state wind
    3. Offshore wind
- Marginal ELCC is relatively stable over a range of wind capacity, based on the capacity factors on high net load days
  - Offshore wind ELCCs have dropped since prior cycle due to updated offshore wind output shapes showing lower output on high net load days





Considering a two dimensional "surface"....

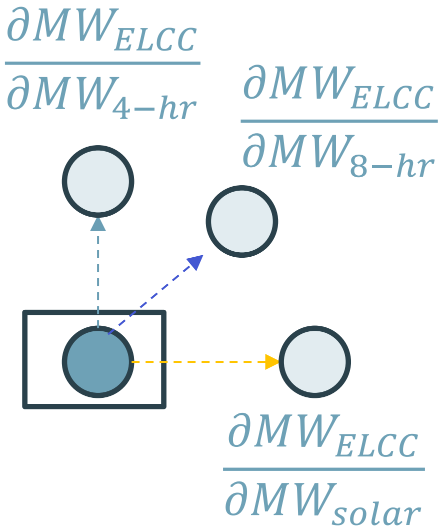
- An ELCC surface with two resource classes can capture both diminishing returns and diversity benefits between resources

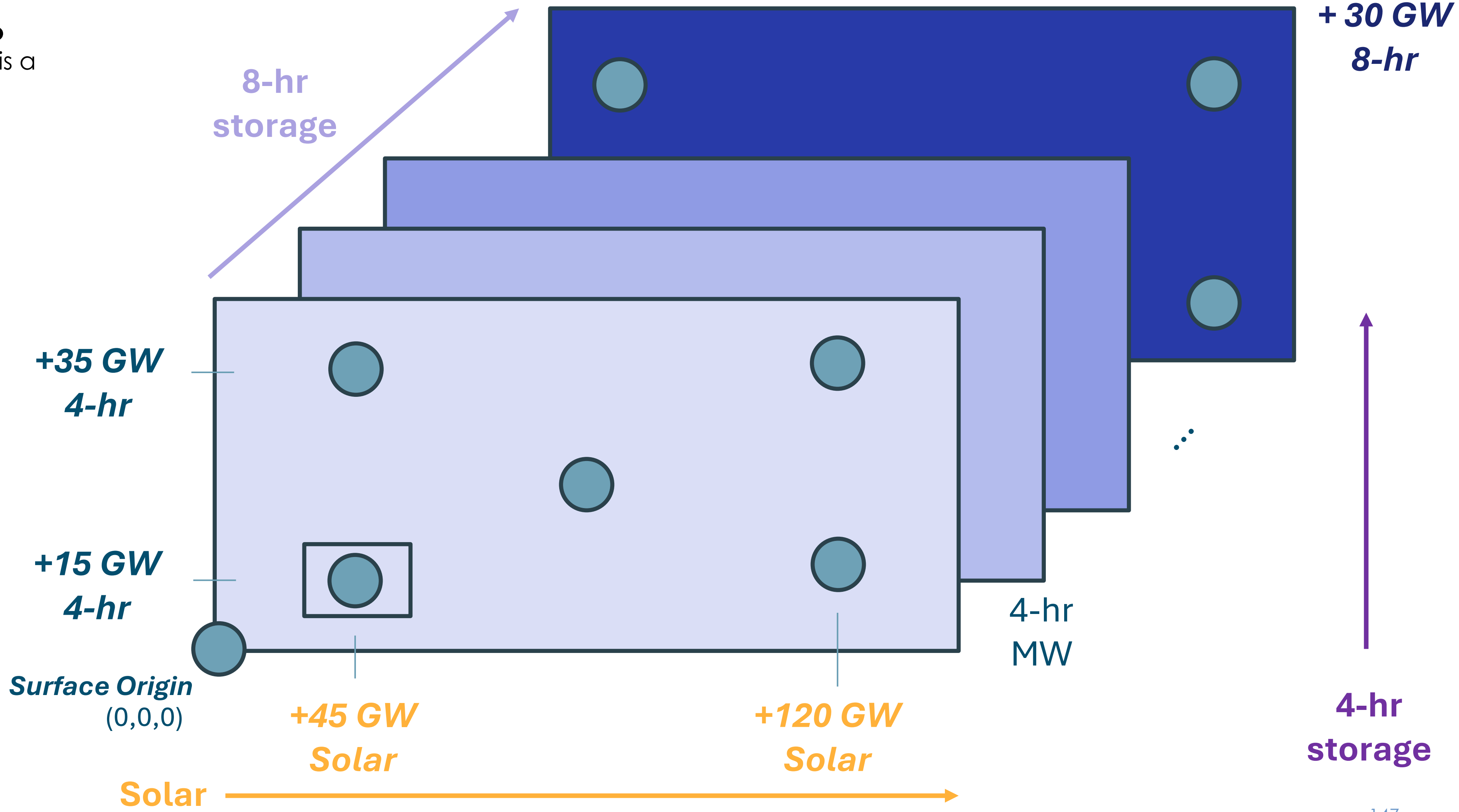


…adding another dimension creates a 3D solar, 4-hr storage, and 8-hr storage surface

Solar and Storage Portfolio ELCC: Each surface point is a solar + 4hr storage + 8-hr storage portfolio ELCC calculation

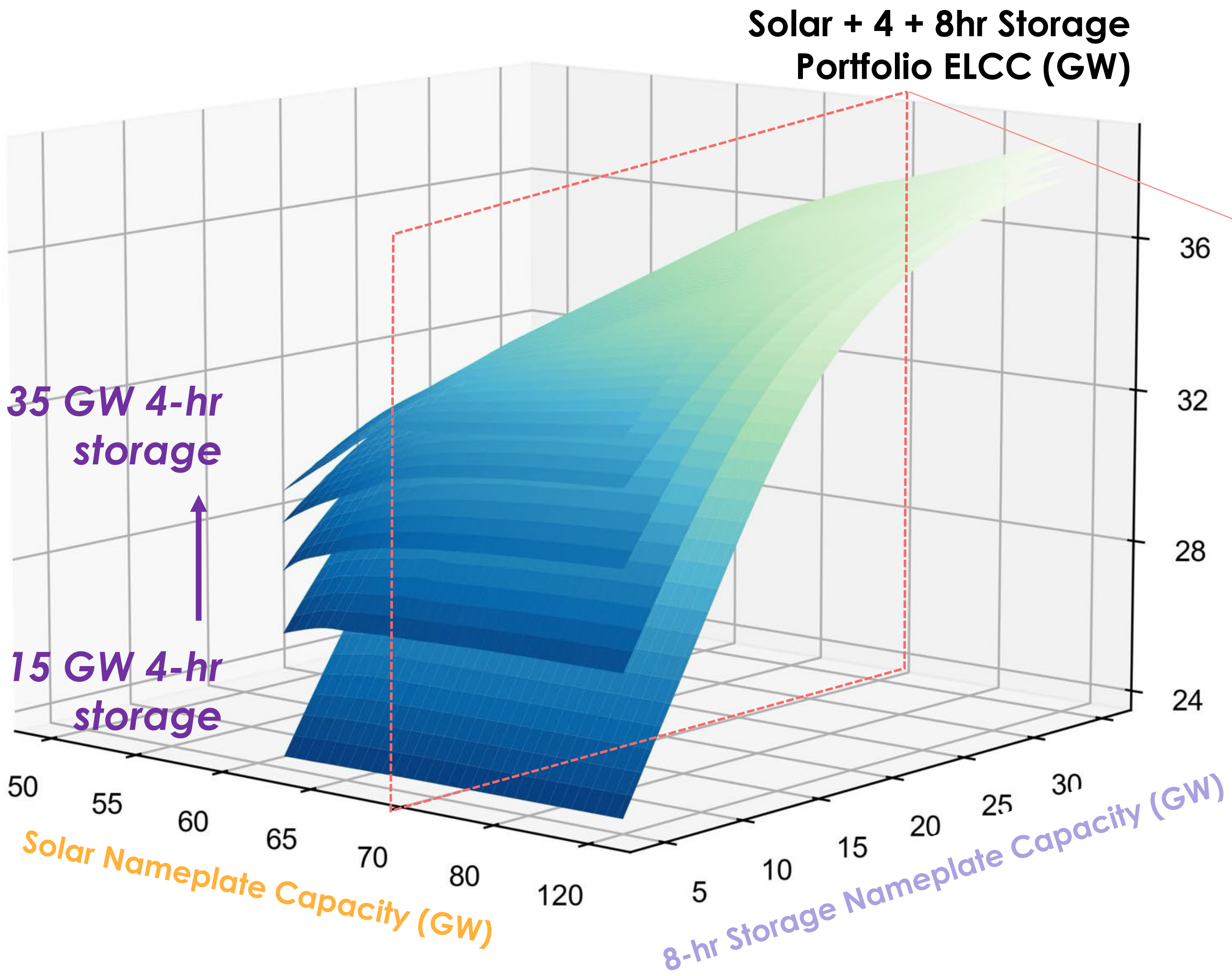
MARGINAL ELCC: Measured as the change in ELCC between each point

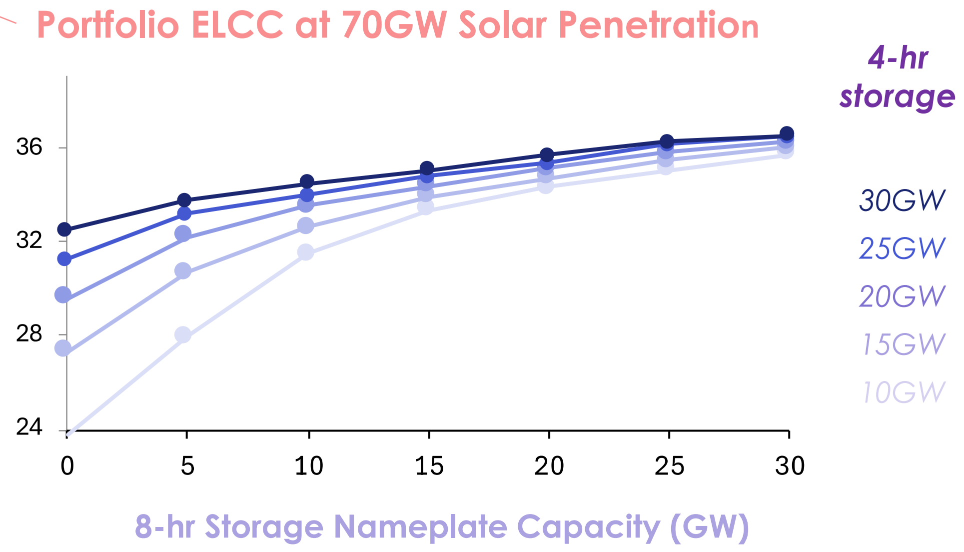




The 3D solar-4hr_storage-8hr_storage was developed via SERVM runs at 280 distinct resource combinations.

Solar + Storage Portfolio ELCC in 3D





Solar and Storage ELCC Results

- The 3-D solar / 4-hr storage / 8-hr storage surface captures key interactions
  - More storage --> increased solar marginal ELCCs for peak shift and charging energy
  - More solar --> increased storage marginal ELCCs to serve remaining net peak
  - More 4hr storage --> reduces 4-hr storage ELCCs and reduces (more slowly) 8-hr storage ELCCs

Solar Marginal ELCC %

		Energy Storage					
		0	0	0	0	0	8hr
		15	20	25	30	35	4hr
Solar	50				9%		
	55				7%		
	60				6%		
	65	0.2%	0.6%	3%	6%	9%	
	70				6%		
	80				3%		
	120				1%		

4hr Storage Marginal ELCC %

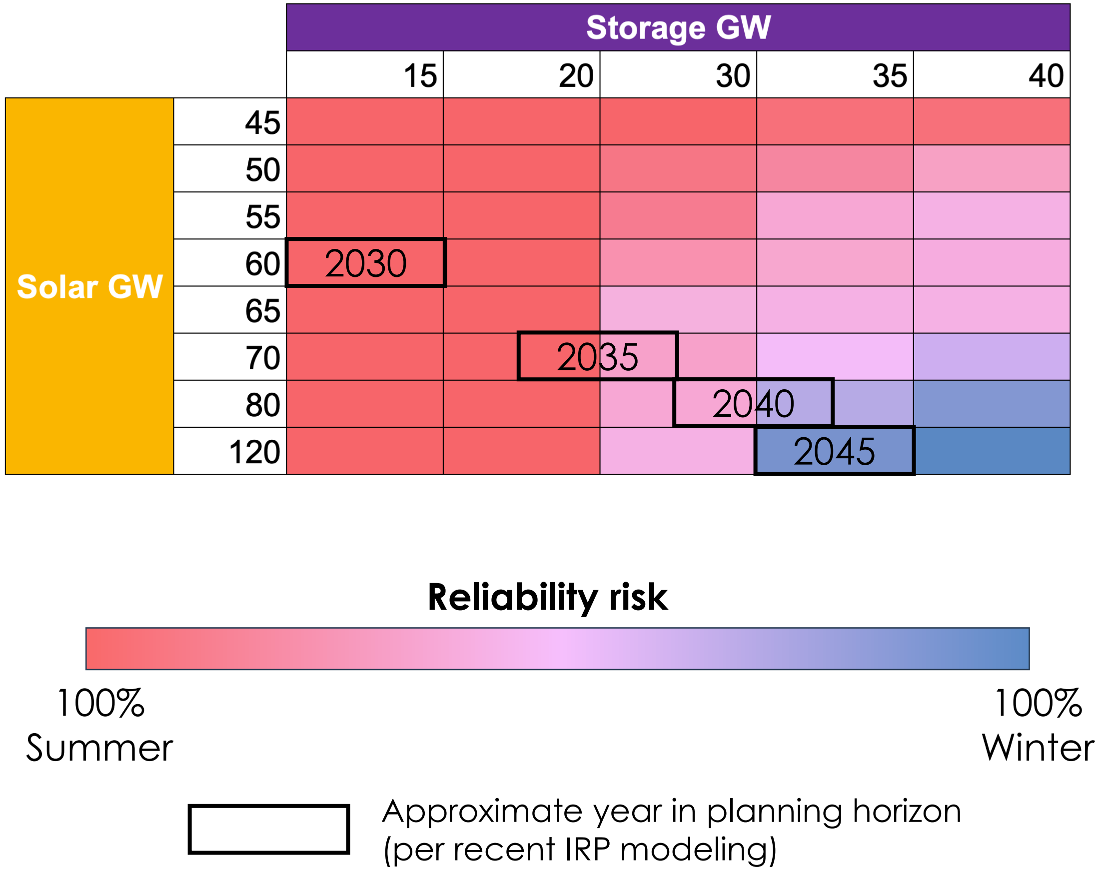
		Energy Storage					
		0	0	0	0	0	8hr
		15	20	25	30	35	4hr
Solar	50		66%				
	55		69%				
	60		70%				
	65		70%	43%	30%	26%	
	70		71%				
	80		71%				
	120		72%				

8hr Storage Marginal ELCC %

@ 60 GW of solar		4hr Storage				
		15	20	25	30	35
8hr Storage	5	82%				
	10	63%				
	15	32%	25%	19%	15%	11%
	20	16%				
	25	15%				
	30	13%				

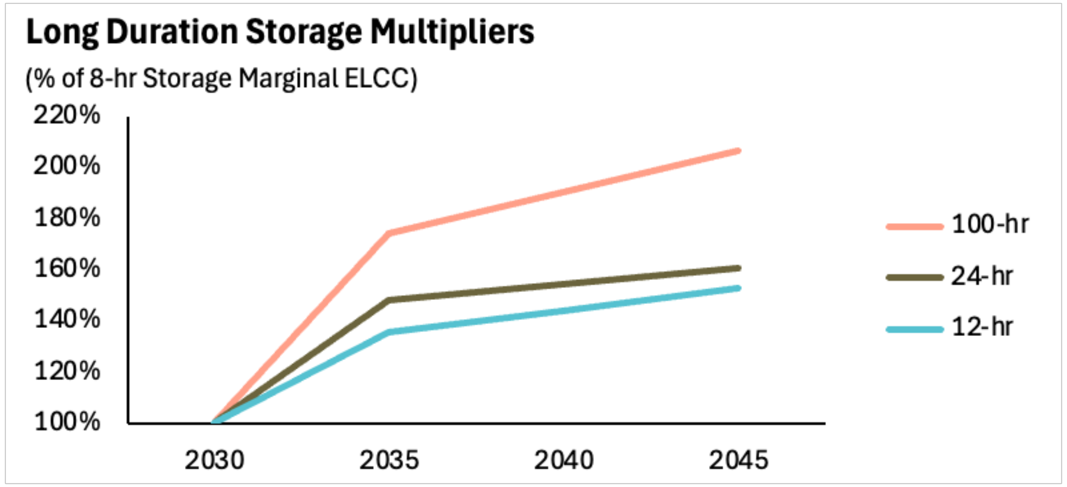
Summer vs. Winter Reliability Risk

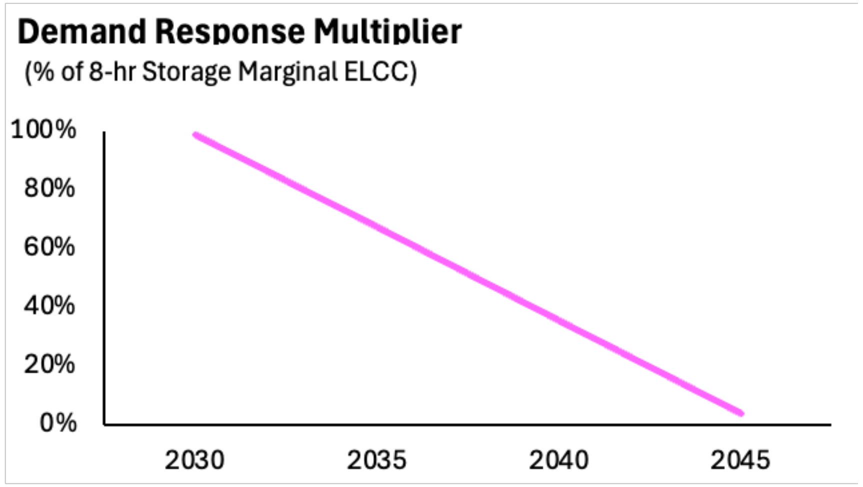
- Load and resource changes between 2030 and 2040 are expected to shift the marginal periods of reliability risk from the summer to the winter
  - In studying the solar + storage surface ELCCs, it was found that in the expected resource penetrations reached by 2035-2040, reliability risk shifts significantly into the winter
- Key considerations for how quickly this shift occurs:
  - Rate of space heating electrification
  - Winter maintenance schedules for thermal units
  - Level of out-of-state + offshore wind (and their output on winter peak days)
  - Climate impacts on temperature and electricity demand in winter vs. summer



Long Duration Storage and New DR Multipliers

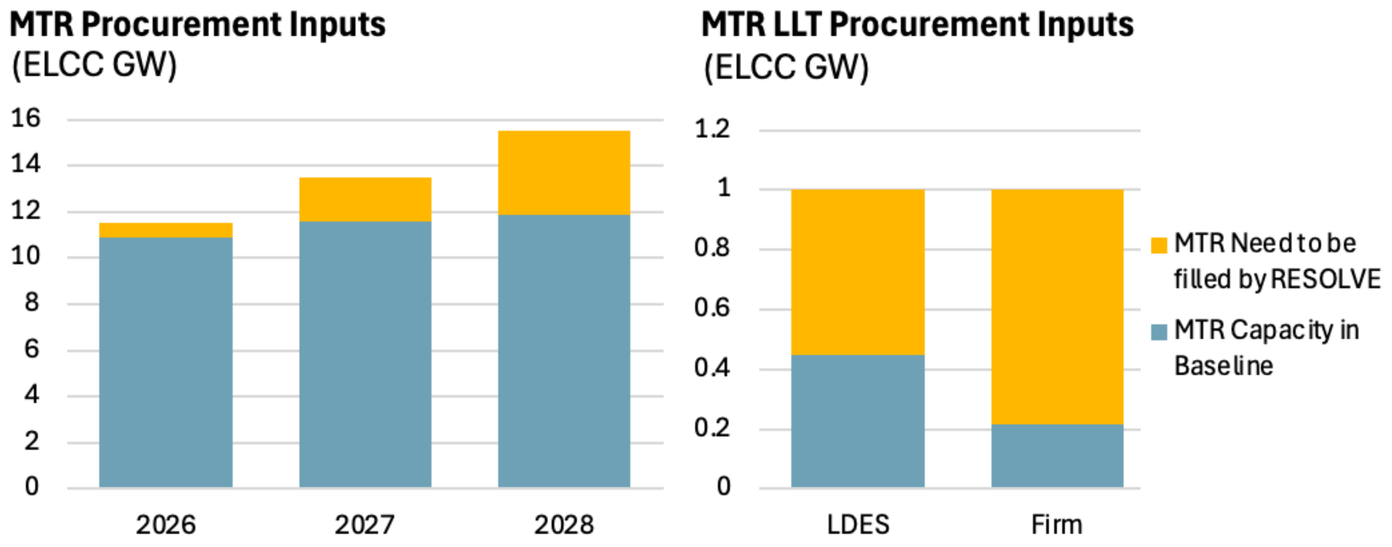
- LDES and DR multipliers were developed by comparing marginal ELCCs against 8-hr storage marginal ELCCs at various points in the solar and storage surface
- Longer duration storage (12, 24, and 100-hr) is represented via a multiplier (>100%) above the 8-hr storage marginal ELCC
  - Years for these multipliers are estimated from preliminary portfolio results (where RESOLVE lands on the surface in future years)
- DR is represented via a multiplier (<100%) below the 8-hr storage marginal ELCC
  - DR value declines rapidly as storage is added and the system becomes energy limited with extended duration net peak events





Mid-Term Reliability (MTR) Target

- MTR procurement for 15.5 GW NQC of zero-emission resources ordered in D.21-06-035[1] and D.23-02-040[2] by 2028, modeled separately from the PRM target
  - Resources are accredited for MTR using ELCCs from the MTR ELCC Report[3]
- D.24-02-047[4] extended the deadline for Long Lead Time (LLT) procurement to 2031
  - 1 GW NQC Long Duration Storage (8+ hour duration)
  - 1 GW NQC Clean Firm (>80% capacity factor)
- Significant amounts of MTR capacity is now in the baseline (online and in-development resources); the MTR target in RESOLVE is adjusted accordingly
  - RESOLVE only needs to fill the remaining gap between the baseline and the total MTR requirements

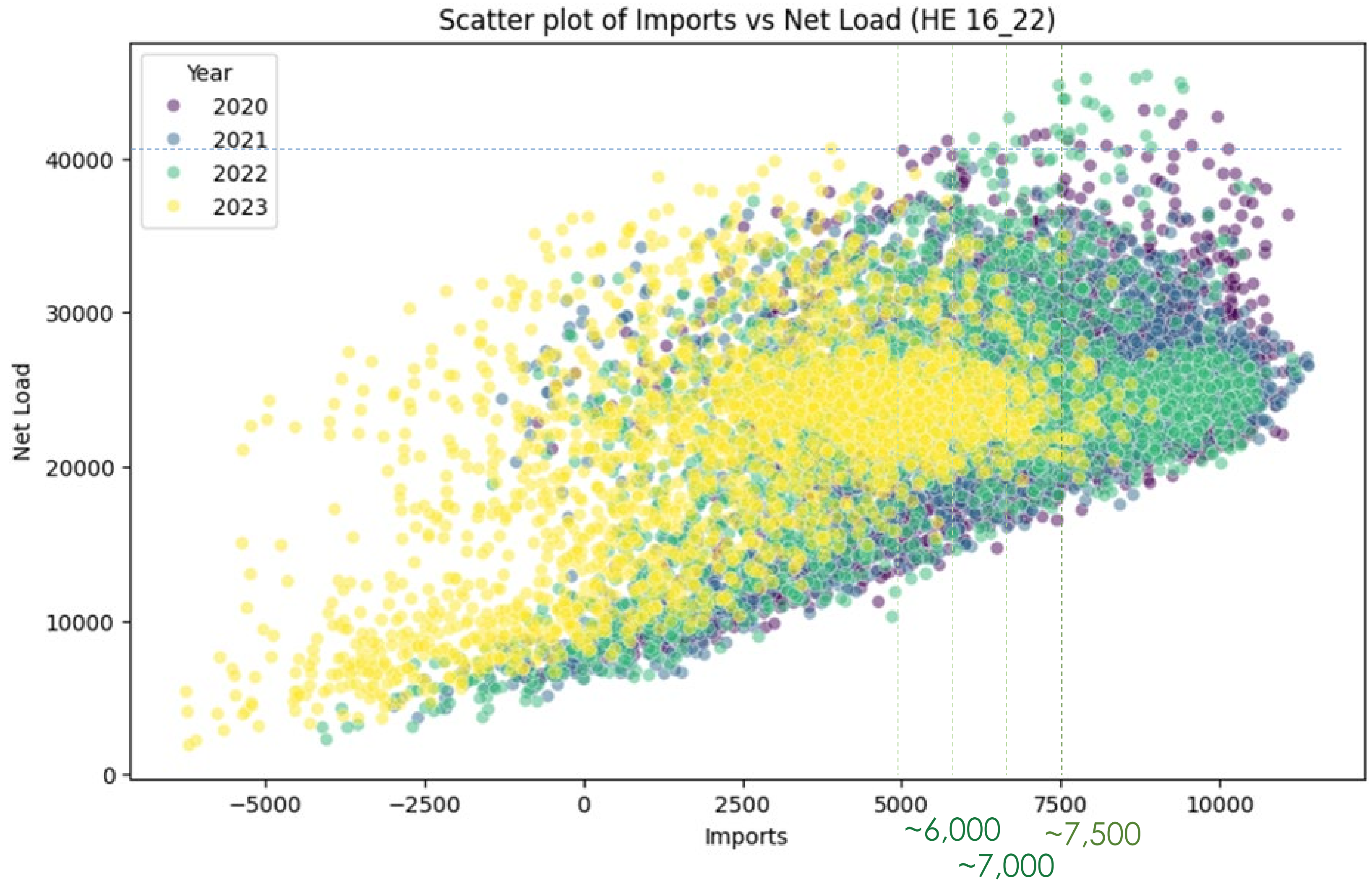


1 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF;
2 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF;
3 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf; 4 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K918/525918033.PDF

Imports Accounting for Reliability

Historically Observed Imports in Highest Net Load Hours

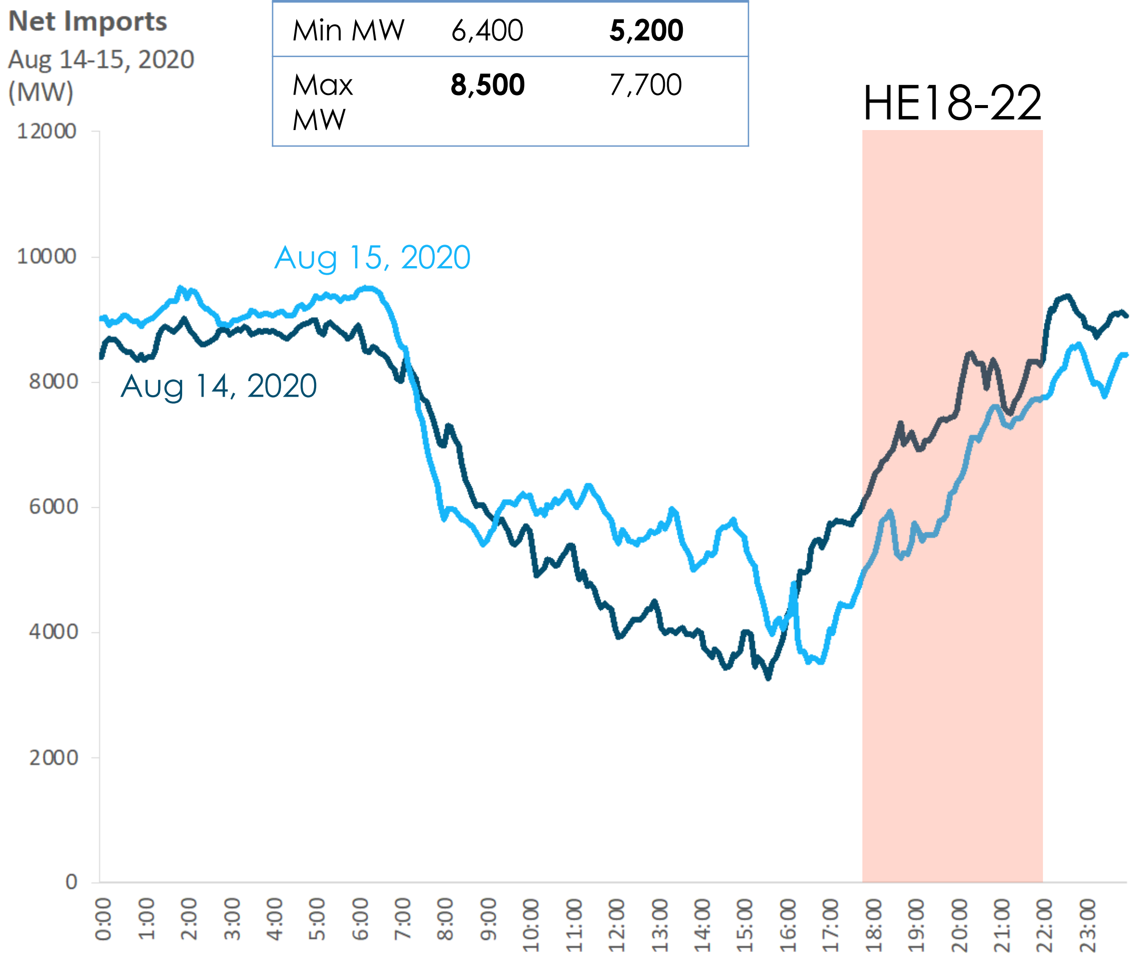
CAISO OASIS 2020-2023 Data



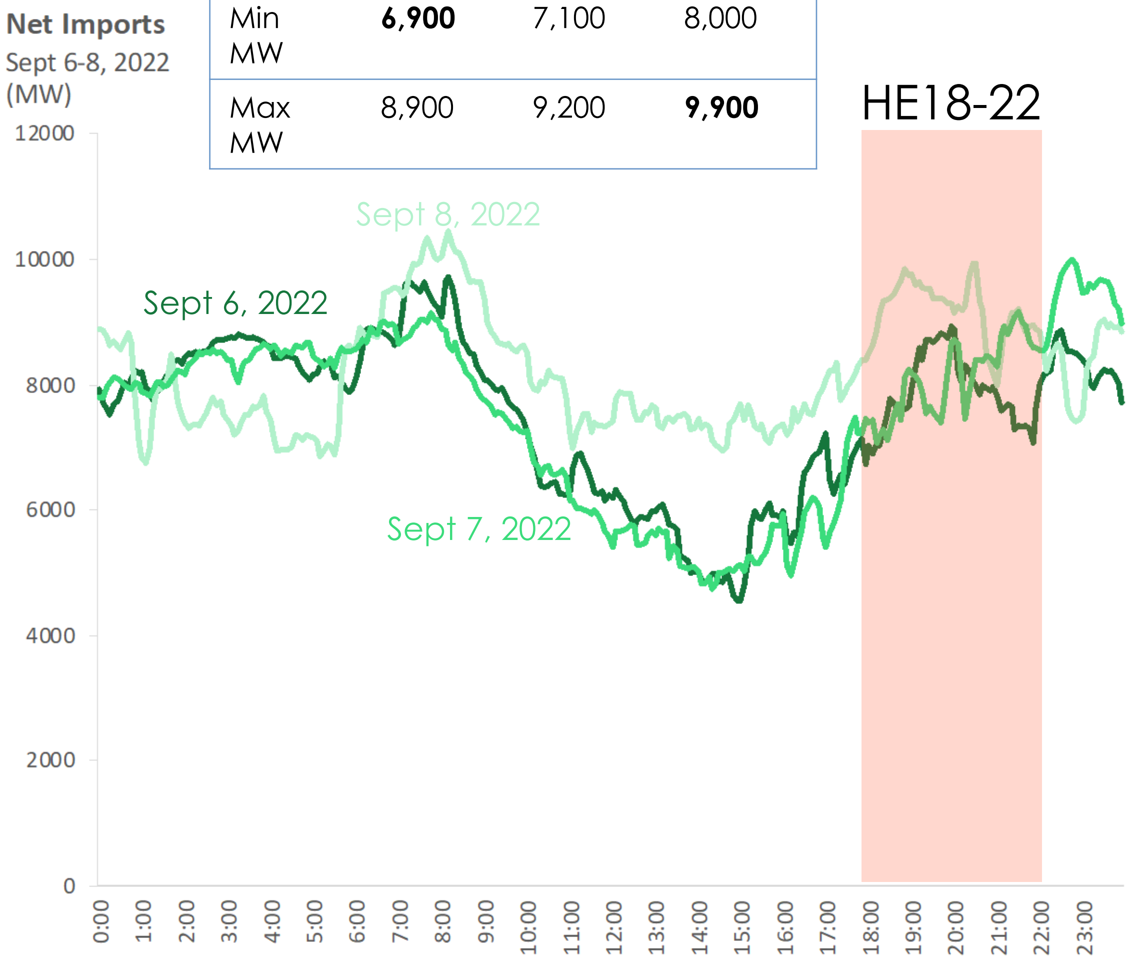
- Imports increase as net load increases, but with wide variance in the few data points above 40,000 MW net load
- Highest net load hours in analysis (past 4 years) all occur in 2022
  - Nearly all of the top net load hours (40 GW+) have imports > 5,000 MW
  - 90% of the top net load hours have imports > ~6,000MW
  - The expected value (50% of top net load hours) have imports ~7,500 MW

Imports during Aug 2020 + Sept 2022 Heat Waves

	Aug 14	Aug 15
Min MW	6,400	**5,200**
Max MW	**8,500**	7,700



	Sept 6	Sept 7	Sept 8
Min MW	**6,900**	7,100	8,000
Max MW	8,900	9,200	**9,900**



RA Imports Modeling Overview

- SERVM simulates neighboring loads and resources, while also applying a cap on imports HE17-22 in the summer
- RESOLVE accounting for RA imports is designed to reflect SERVM modeling
- **Specified imports** represent capacity contributions from 6 units with firm RA
- **Unspecified imports** represent ALL additional imports beyond those 6 units
  - Includes:
    - A) additional contracted "specified" imports (i.e. those on the specified imports list in the MRD)
    - B) contracted unspecified imports
    - C) economic imports available during the net peak (beyond those contracted by LSEs)
  - Currently set at 4 GW per SERVM net peak limit

Specified Import Unit	Installed MW	ELCC %	ELCC MW	Notes
Hoover	594	56%	331	Existing
Palo Verde	635	100%	635	Existing
Sutter	275	92%	253	Existing
Intermountain	480	79%	377	Retires in 2025
SunZia	1585	~25-30%	~400-475	Online in 2027, ELCC from OOS Wind curve
Cape Station	320	95%	303	Online 2027/28

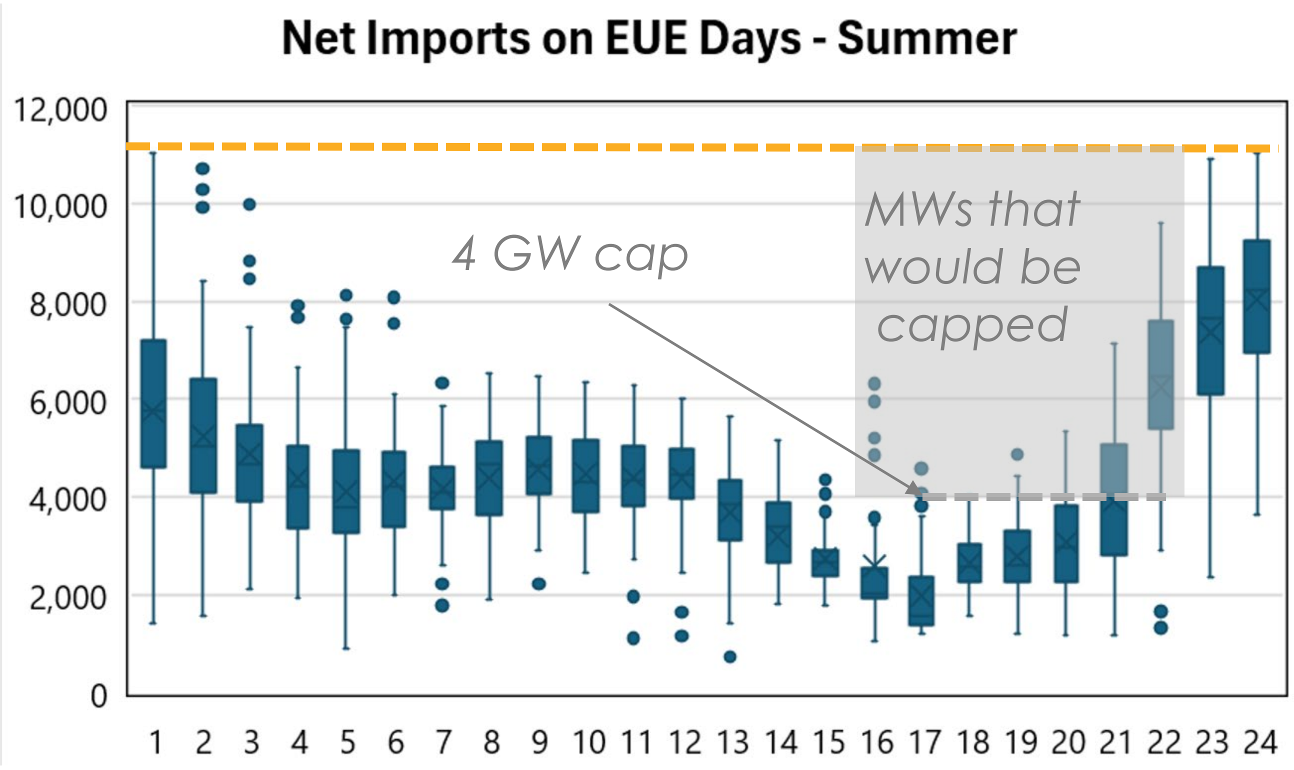
Summary of Recent Import Trends

	Source	Import Availability During Net Peak	Import Availability In Other Hours
RA Supply Plan (Unspecified Imports + Specified Imports) *Note: excludes economic (uncontracted) imports*	CPUC RA Supply Plans, NQC Lists	~5-6 GW	*These data sources do not provide reliable estimates of future off-peak import potential… instead this is informed via a fundamentals-based approach using SERVM analysis with calibrated external regions with forecasted load and resource growth*
Sep 6-8, 2022 Imports during Net Peak (HE 16-22)	CAISO Today's Outlook	~7-10 GW	
Aug 14-15, 2020 Imports during Net Peak (HE 16-22)	CAISO Today's Outlook	~5.2-8.5 GW	
Current Assumption	Prev Analysis	4 GW (+ 1.9 GW spec.) = ~6 GW total	11.7 GW

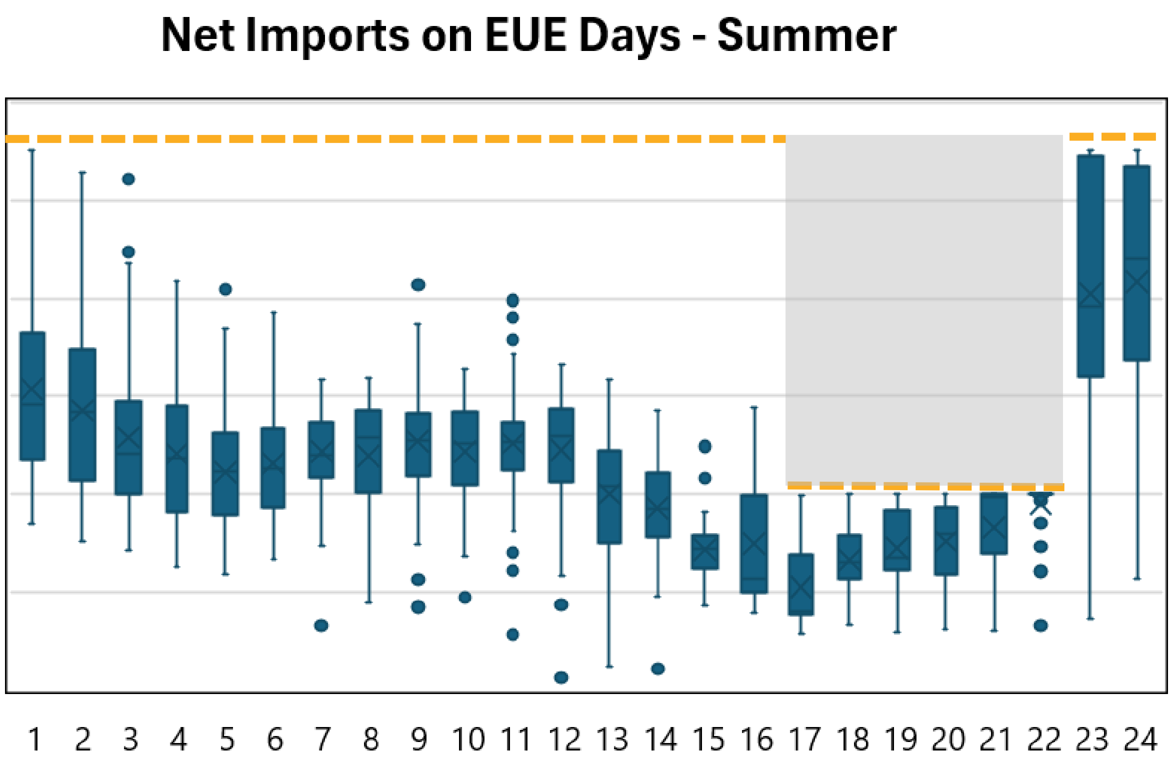
A 4 GW "net-peak" cap (HE17-HE22) has a small impact on modeled imports and only significantly binds in HE21-HE22

- SERVM simulations using updated external zone loads + resources (calibrated to 0.1 LOLE) show less than 4 GW available during many net peak hours

2026 – **11 GW cap only**

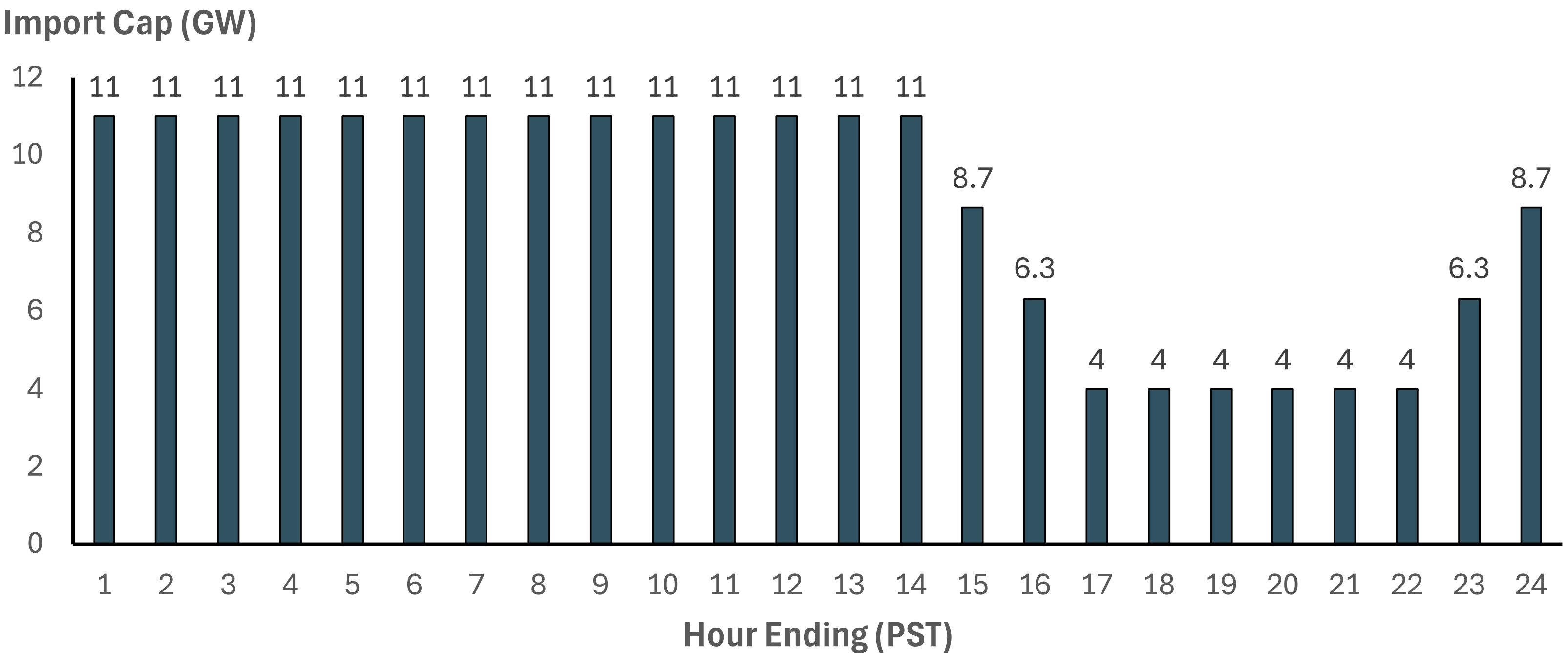


2026 – **4 GW / 11 GW cap**



Final Import Cap Shape

- Continued solar and storage growth in neighboring regions is expected to expand the hours of energy constraints for available imports
- In recognition of this, a ramp was added before and after the 4 GW limit between HE 17-22



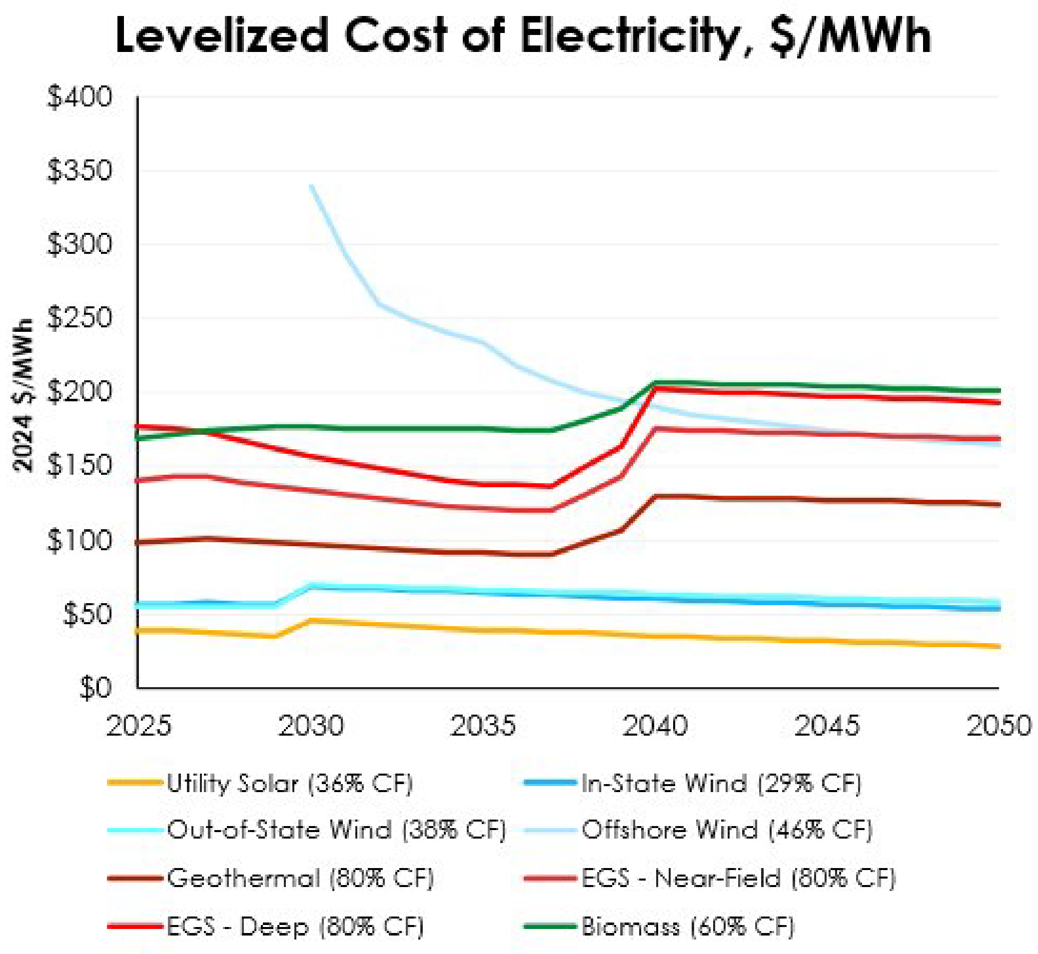
Updates to Inputs and Assumptions for the 26-27 TPP

Resource Cost Updates

Changes for 26-27 TPP

Summary of Resource Cost Updates

- Policy trajectories shifted materially in Q2 2025, leading to the following updates:
  - Impacts of the OBBBA are reflected via revised tax credit assumptions for renewables, energy storage, and other clean firm technologies
  - Wide-ranging tariffs were announced and applied across U.S. trading partners, impacting every technology but which are especially impactful for technologies dependent upon imports from China and Southeast Asia
- Additional policy drivers of near-term resource costs, including Anti-Dumping and Countervailing Duties (AD/CVD) and Foreign Entities of Concern (FEOC) regulations, are being monitored for additional Treasury guidance but are not reflected in these updates



Tax Credit Assumption Updates

- The OBBBA has ended tax credits for wind and solar projects that fail to commence construction by July 3, 2026
- Energy storage and clean-firm technologies retain tax full eligibility through 2032, as well as safe-harboring provisions and the three-year phase-out established in the IRA

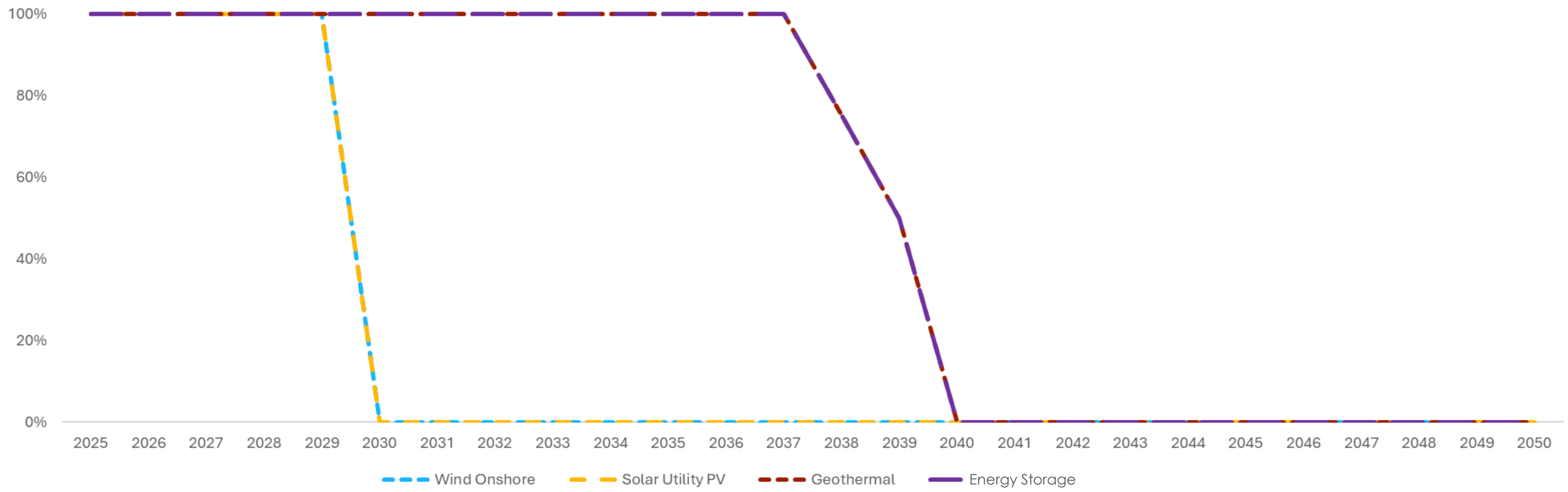


Figure adapted from E3 RECOST (2025 Q3), https://www.ethree.com/tools/recost-model/

Tariff Assumptions for Key Technologies

- Current tariff and tax policy (post-OBBBA) is assumed to last through 2029, reflecting precedent in federal trade policy
- U.S. trade policy impacts by technology are estimated by assessing the supply chains of imported components by country, and applying the latest tariff rates (as of mid-July 2025) to the proportions of project CAPEX attributable to those imports
- Tariff impacts are largest for solar and Li-ion battery storage, which source most of their components from China and Southeast Asia
- These results assume that solar developers will be able to adapt their supply chains to avoid AD/CVD penalties
- The BESS supply chain is uniquely dependent on imports from China, which is subject to some of the highest tariffs applied under current U.S. policy

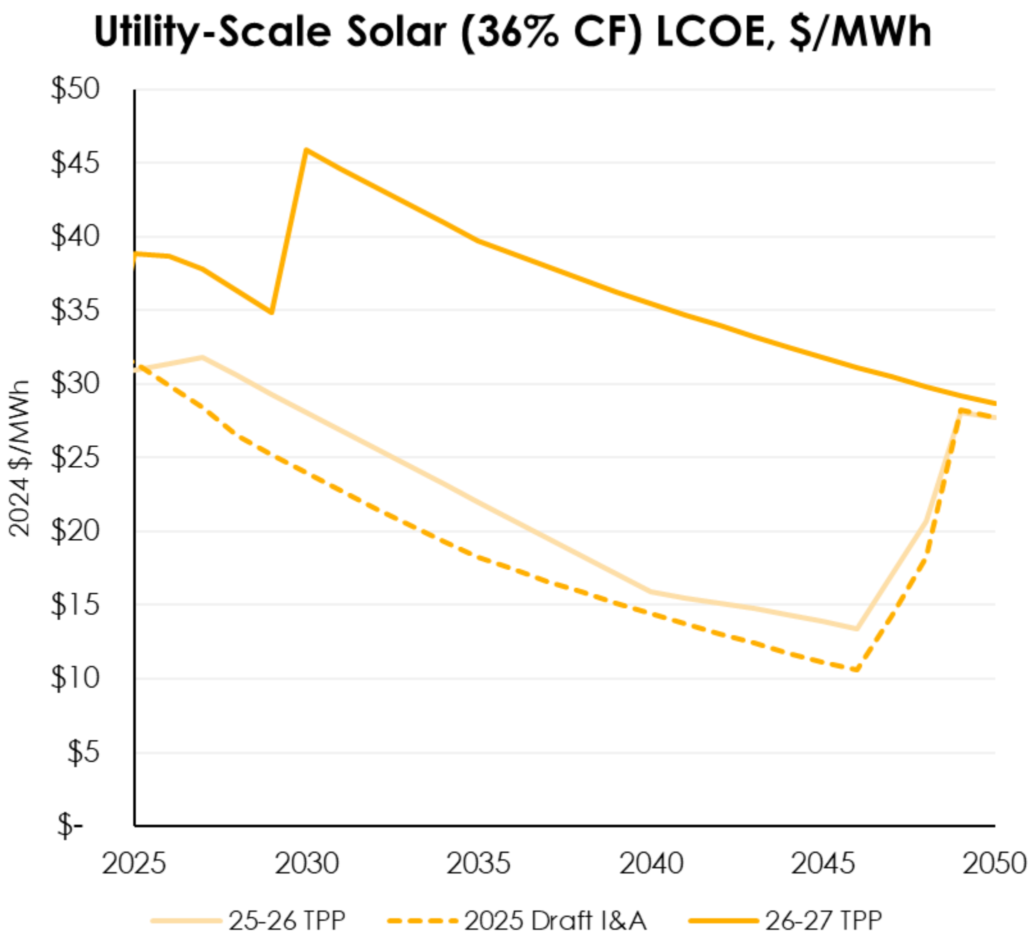
Tariff Impacts for Key Technologies

Technology	Key Imports (Countries)	Capex at Risk (% Total)	Weighted Average Tariff (% Rate Applied to Capex at Risk)
Wind (Onshore)	Nacelle, rotors, towers (Mexico, Germany)	55%	29%
Solar (Utility PV)	Module and BOS (Vietnam, China)	44%	70%
BESS (Standalone, Li-ion)	Cabinets and BOS (China)	73%	121%

Figure adapted from E3 RECOST (2025 Q3), https://www.ethree.com/tools/recost-model/

Utility-Scale Solar Cost Updates

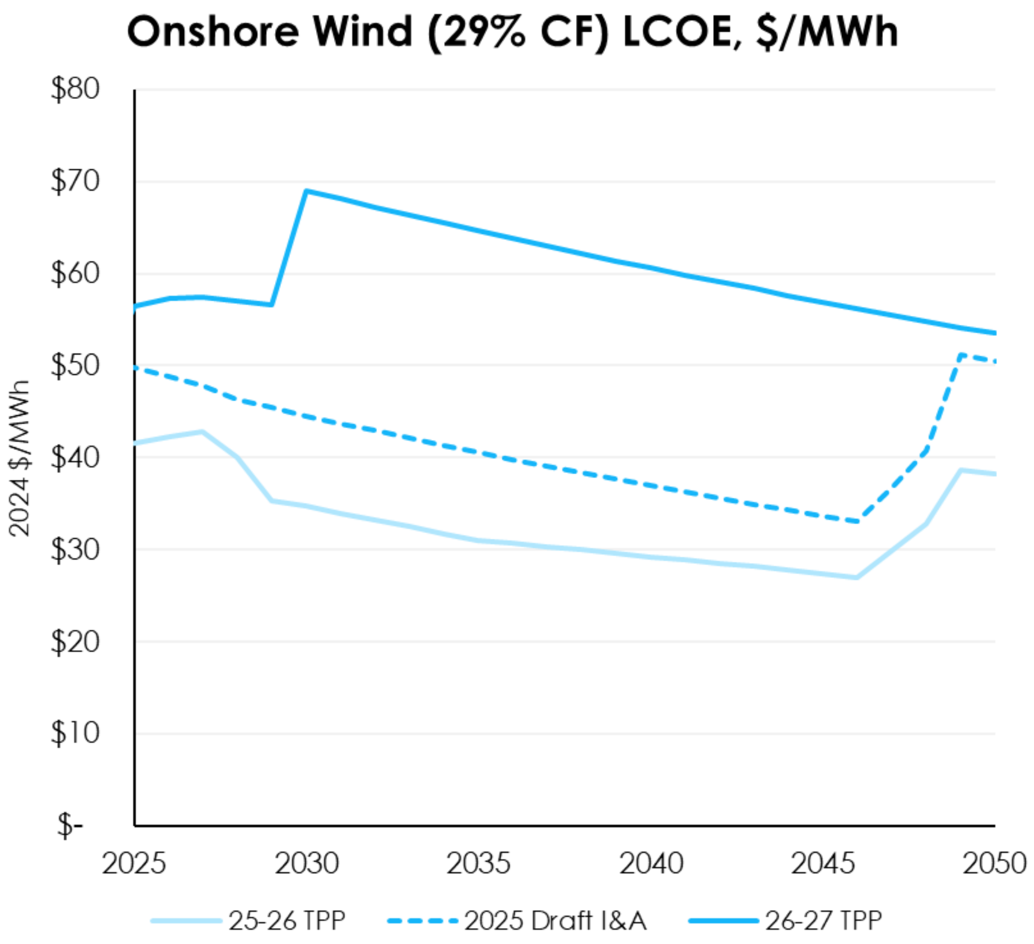
- Under the base tariff rates, utility-scale solar LCOE is estimated to increase by ~25% in the near-term, with additional impacts once the supply of safe-harbored modules is exhausted by 2030
- Additional impacts due to AD/CVD and FEOC regulations are not captured here; the tariff exposure risk for projects unable to adjust their material suppliers is extremely high



Note: LCOE is not used as an input in IRP modeling and is reported as reference only.

Onshore Wind Cost Updates

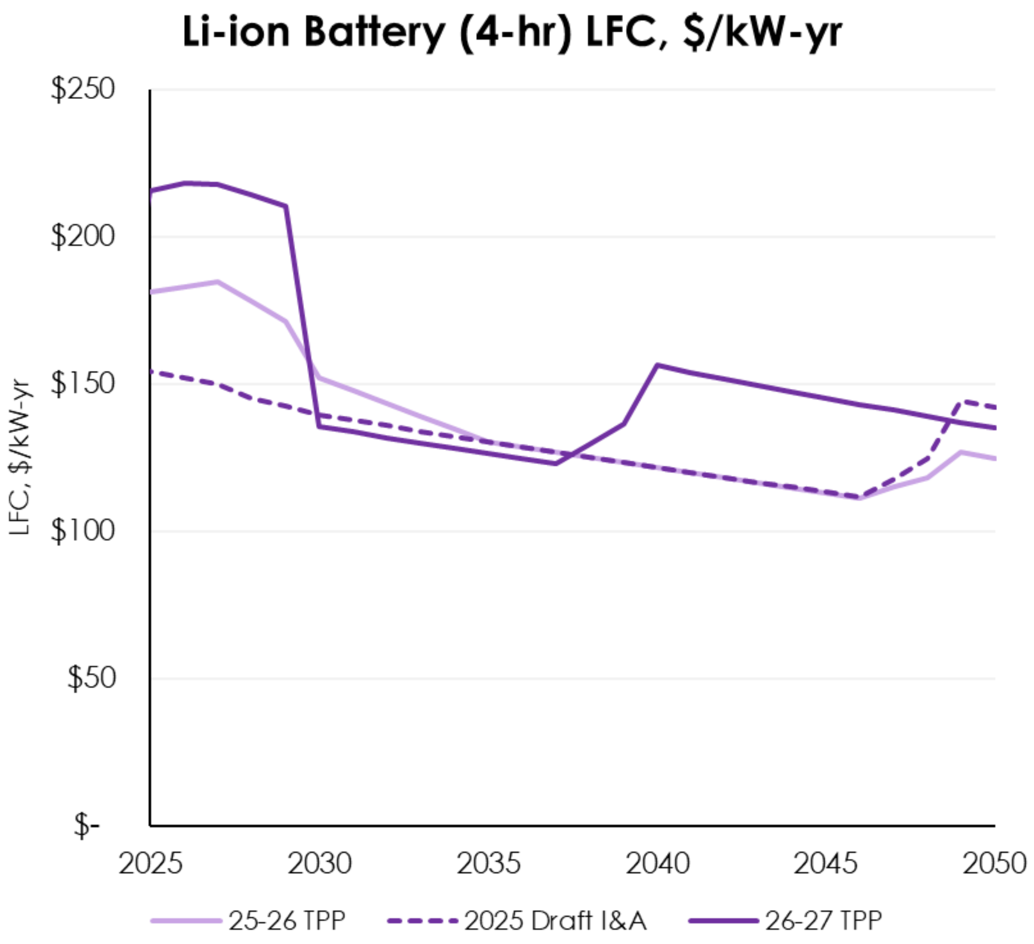
- The supply chain for wind turbines is less impacted by tariff policy
- Onshore wind projects face additional pressures from recent federal policies delaying or canceling projects sited on federal land or seeking federal permits
  - These near-term pressures are not assumed to impact resource procurements in the timeline of the TPP (2036-2041)



Note: LCOE is not used as an input in IRP modeling and is reported as reference only.

Li-ion Battery Storage Cost Updates

- The supply chain for battery storage components is highly dependent on suppliers in China, which has been flagged as a Foreign Entity of Concern (FEOC) by the DOE
- Under preliminary federal guidance, BESS project developers will need to demonstrate that the majority of CAPEX is not sourced from Chinese suppliers, or else risk forfeiture of federal tax credits
- Battery costs in RESOLVE include tariff impacts on Li-ion battery storage costs assuming pre-OBBBA resource supply chains, but does not consider FEOC restrictions on tax credit eligibility



Resource Potential and Transmission Updates

Changes for 26-27 TPP

In-State Wind Resource Potential Updates

- The in-state wind resource potential in RESOLVE has been updated to incorporate one new data layer, and updates to two CEC land-use screens:
  - Global Wind Atlas (GWA) Mean Annual Wind Speed[1] (replacing NLR supply curve)
  - CEC Protected Areas Layer[2]
  - CEC Core Land-Use Screen[3]
- GWA publishes mean annual wind speeds at 100-m hub height and 250-m lateral resolution; a minimum annual average wind speed of 6.5 m/s was set as the cut-off value for commercial viability
- The techno-economic screen[4] and updated PAL and environmental screens are subtracted from the high-wind-speed areas to yield the net acreage suitable for development
- For RESOLVE, available land area is divided using a 4-km grid into candidate project areas; each area is screened for a minimum suitable project area of 0.5 km^2 (~1 turbine) and maximum distance of 30 miles from an electrical substation
- MW potentials for RESOLVE are estimated using a 40 acre/MW density factor

[1] https://globalwindatlas.info/en/
[2] *To be discussed in a later section. This layer includes data for CAISO-controlled portions of southern Nevada and western Arizona*
[3] *To be discussed in a later section. This layer only applies to California; out-of-state regions use the WECC Environmental Risk Class dataset*
[4] https://cecgis-caenergy.opendata.arcgis.com/datasets/b99eaaf368c54953844b578a92b0cd63_0/explore

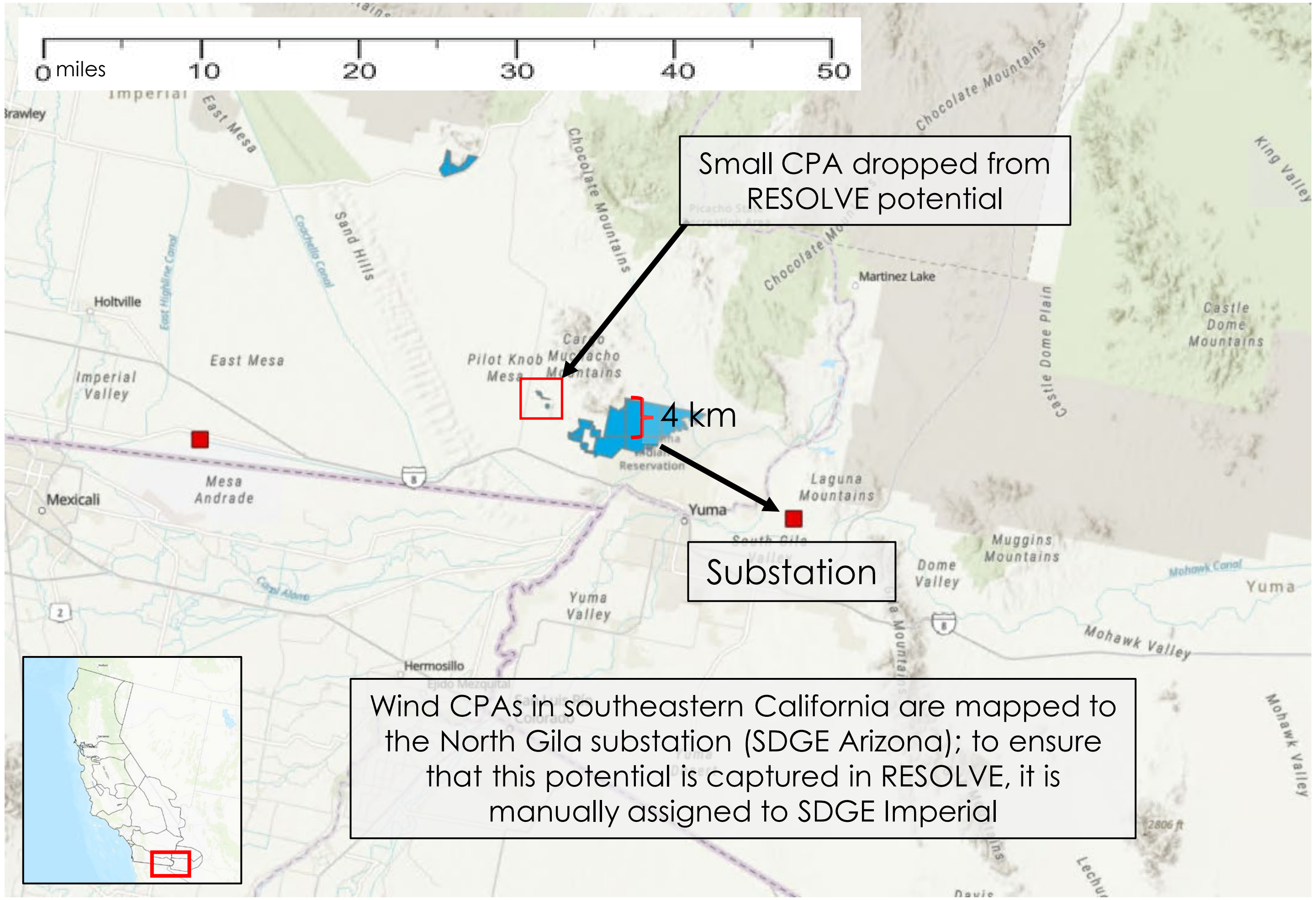
Wind Potential Totals by Study Area (MW)

Study Area	2025 Draft I&A	26-27 TPP	Delta
Northeast CA	N/A	584	+584
PG&E NGBA	2,872	1,894	-978
PG&E GBA	231	245	+14
PG&E Fresno	2,228	-	-2,228
PG&E Kern	91	245	+154
SCE Northern	1,701	2,447	+746
SCE Metro	-	-	-
SCE NOL	948	1,243	+295
SCE Eastern	165	819	+654
SCE EOP	1,399 (1)	241	-1,158
SDGE Imperial	251	971 (2)	+415
Baja California	2,473	1,654 (3)	-819
Total	**12,359**	**10,344**	**-2,015**

[1] *The SCE EOP total from the Draft I&A assumes a 50% haircut to the total potential; no additional haircut is applied to the updated 26-27 TPP result*
[2] *Includes 305 MW of wind in southeastern CA interconnecting to the North Gila substation in AZ*
[3] *The Baja California potential was revised based on review of projects in the CAISO interconnection queue*

Converting Land Area to Resource Potential in RESOLVE

- Land area is partitioned using a 4-km fishnet
- Each 4-km square becomes a "candidate project area" (CPA)
- MW totals are calculated using density factors:
  - Solar: 8.24 acre/MW (DC)
  - Wind: 40 acre/MW
- CPAs are assigned to substations using a nearest-neighbor algorithm
- All CPAs are screened for a maximum distance to nearest substation of 30 miles
- Wind CPAs are additionally filtered for a minimum viable project size of 3.3 MW[1]
- The resource potential is first summed to produce totals by substation; then, the potentials for RESOLVE are calculated by summing across the substations within each Study Area



[1] Represents the T3 turbine rating from NLR 2024 ATB: https://atb.NLR.gov/electricity/2024/land-based_wind.

Enhanced Geothermal Resource Potential Totals

- EGS is assumed to be available for procurement in California, Oregon, Nevada, Idaho, and Utah
- For deep EGS, only the in-CAISO (including IID) 3-km potential will be used in IRP modeling; all out-of-state deep EGS (including Northeast CA) will be excluded
- The representation of deep EGS on transmission is expanded to represent the full locational dependency of the resource potential on the transmission system
- All non-CAISO EGS will incur additional transmission costs to deliver to the CAISO system

Resource Region	Near-Field EGS (MW)	Deep EGS (3 km) [1,2]
PG&E	668	15,461
SCE	2,025	1,115
SDGE	529	438
CAISO Total	3,224	17,016
Northeast CA[3]	178	4,264
Nevada[3]	4,364	Not modeled
Oregon[3]	1,893	Not modeled
Idaho[3]	1,872	Not modeled
Utah[3]	1,464	Not modeled

[1] In-state totals reflect amounts within 30 miles of electrical substation. Out-of-state totals reflect total potential.

[2] Based on the amount of Deep EGS potential at 3-km depth, and the incremental drilling costs to access EGS at deeper depths, only the Deep EGS potential at 3-km will be modeled in RESOLVE

[3] Transmission pathways for non-CAISO EGS are assumed to be identical to those for hydrothermal resources

Note: This is a modeling build limit and has no direct impact on actual build rate.

Annual Resource Build Limits

- In the 2025 Draft I&A MAG webinar, Staff updated the near-term solar build limit to 4,000 MW/year through 2028, based on annual procurement rates from LBNL Tracking the Sun[1] and the CAISO Master Generating Capability List (MGC)[2]
  - For the 26-27 TPP, the limits have been revised to reflect the system need required to meet GHG policy in 2028
- For the 26-27 TPP, Staff introduced near-term build limits for in-state wind and geothermal, reflecting commercial interest, procurement challenges, and project deployment timelines
  - Wind: 250 MW/year through 2030, 1,000 MW/year from 2031 through 2035
  - Geothermal: 200 MW/year through 2032
- The full resource potential, subject to resource-level near-term build limits and transmission deliverability constraints, will continue to restrict capacity additions after these constraints are relaxed

Technology (Cumulative MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036+
Utility-Scale Solar	4,000	9,000	15,000	Full potential							
In-State Wind	250	500	750	1,000	1,250	2,250	3,250	4,250	5,250	6,250	Full
In-State Geothermal	200	400	600	800	1,000	1,200	Full potential				

1 https://emp.lbl.gov/utility-scale-solar; 2 http://oasis.caiso.com/mrioasis/logon.do

Near-Term Wind Resource Build Limits by Study Area

- Additional restrictions for wind resources were identified by reviewing the CAISO interconnection queue, Cluster 15 project queue, and queues from neighboring jurisdictions; these limits restrict wind procurements up until 2035

Resource (Cumulative MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Northeast CA Wind	300	300	300	300	300	300	1,015	1,015	1,015	Full Potential
PG&E NGBA Wind	0	206	206	206	206	206	206	206	206	
PG&E GBA Wind	266	266	990	990	1,399	1,399	1,399	1,399	1,399	
PG&E Fresno Wind	80	80	80	80	80	80	292	292	292	
SCE Northern Wind	0	0	100	206	206	206	206	206	206	
SCE NOL Wind	0	213	213	316	316	316	316	316	316	
SCE Eastern Wind	0	0	0	0	676	676	676	676	676	
SCE EOP Wind	1,050	3,618	3,618	3,719	3,719	3,719	3,719	3,719	3,719	
SDGE Imperial Wind	0	0	194	194	194	700	1,701	1,701	1,701	
SDGE Baja California Wind	353	353	353	353	353	353	653	653	653	

Near-Term Geothermal Resource Build Limits by Study Area

- Additional restrictions for geothermal resources were identified by reviewing the CAISO interconnection queue, Cluster 15 project queue, and queues from neighboring jurisdictions; these limits restrict geothermal procurements up until 2035

Resource (Cumulative MW)	2026	2027	2028	2029	2030	2031	2032+
Northeast CA Geothermal	0	0	0	0	Full potential		Full Potential
PG&E NGBA Geothermal	0	0	0	0	Full potential		
SCE NOL Geothermal	0	0	0	0	Full potential		
SCE Eastern Geothermal	83	140	357	671	Full potential		
SDGE Imperial Geothermal	0	83	83	83	Full potential		
PG&E Oregon Geothermal	0	0	0	0	Full potential		
PG&E Nevada Geothermal	0	0	0	0	Full potential		
SCE Nevada Geothermal	288	387	411	411	411	411	
SCE Utah Geothermal	0	40	40	80	Full potential		

Minimum Builds: LSE Contracted Resources

- Contracts incremental to the baseline found in the June 2025 IRP Compliance Filings are forced-in to RESOLVE as minimum builds

PG&E Minimum Builds (MW)

Technology	2026	2028	2031
Geothermal	67	68	68
In-State Wind	72	72	72
Out-of-State Wind	-	-	-
Solar	460	1,045	1,155
Battery Storage (4-hr)	852	1,411	1,521
Battery Storage (8-hr)	112	147	160

SCE Minimum Builds (MW)

Technology	2026	2028	2031
Geothermal	42	60	100
In-State Wind	-	-	-
Out-of-State Wind	535	535	535
Solar	2,126	3,829	3,829
Battery Storage (4-hr)	2,396	4,541	4,541
Battery Storage (8-hr)	41	876	876

SDGE Minimum Builds (MW)

Technology	2026	2028	2031
Geothermal	-	-	-
In-State Wind	-	-	-
Out-of-State Wind	-	-	-
Solar	175	275	275
Battery Storage (4-hr)	660	760	760
Battery Storage (8-hr)	25	25	25

Appendices

Appendix: Summary of Candidate Resource Data

Optimized Generator Resource Options

Category	Technology	First Available Year	Representation on CAISO Transmission	Subject to Transmission Interconnection Limits
Renewable	Utility-Scale Solar	2026-2028	Full	Yes
Renewable	Distributed Solar	2026 (first model year)	None	No
Renewable	Onshore Wind (In-State)	2026-2035	Full	Yes
Renewable	Onshore Wind (Out-of-State)	2026-2040	Specified tie-ins	No
Renewable	Offshore Wind	2032-2040	Specified tie-ins	No
Renewable	Conventional Geothermal	2026-2035	Full, with specified tie-ins for out-of-state resources	In-CAISO resources only
Renewable	Enhanced Geothermal (Near-Field)	2030-2035	Full, with specified tie-ins for out-of-state resources	In-CAISO resources only
Renewable	Enhanced Geothermal (Deep)	2035	Partial (1)	In-CAISO resources only
Renewable	Biomass	2028	Partial (1)	Yes
Thermal	CCGT	2030	Partial (1)	Yes
Thermal	CT – Frame	2030	Partial (1)	Yes
Thermal	CT – Aeroderivative	2030	Partial (1)	Yes
Thermal	Reciprocating Engine	2030	Partial (1)	Yes

[1] A single cluster representing the least-constrained substations within each IOU is selected for all thermal resources and longer-duration LDES options, to reduce the number of decision variables in the model

Optimized Storage Resource Options

Storage Types	RTE	Min State of Charge	First Available Year	Resource Potential
4-hr Li-ion Battery Storage	85%	10%	2026	Unlimited, subject to transmission limits
8-hr Li-ion Battery Storage	85%	10%	2026	Unlimited, subject to transmission limits
12-hr Location-Constrained LDES	80%	0%	2031-2037	Limited to specific sites, and subject to transmission limits
12-hr Generic LDES	70%	10%	2031	Unlimited, subject to transmission limits (1)
24-hr Generic LDES	60%	10%	2031	Unlimited, subject to transmission limits (1)
100-hr Generic LDES	45%	10%	2031	Unlimited, subject to transmission limits (1)

[1] A single cluster representing the least-constrained substations within each IOU is selected for all thermal resources and longer-duration LDES options, to reduce the number of decision variables in the model

Summary of Resource Potential by Technology (2025 FR)

Technology	PGE (GW)	SCE (GW)	SDGE (GW)
Utility-Scale Solar	147.5	153.4	57.8
Distributed Solar	11.8	20.3	4.5
Onshore Wind	4.9	4.1	1.9
Out-of-State Wind	4.3	15.0	-
Offshore Wind	28.9	-	-
In-State Geothermal	0.7	2.0	0.5
Out-of-State Geothermal	1.0	1.3	-
Biomass	1.0	0.1	0.1
Location-Constrained LDES (12-hr)	5.5	10.5	0.5
In-State Enhanced Geothermal	16.1	3.1	1.0
Out-of-State Enhanced Geothermal	2.9	6.8	-
Storage (Li-ion, LDES)	Uncapped	Uncapped	Uncapped
Thermal (CCGT, CT, Recip)	Uncapped	Uncapped	Uncapped

Summary of Resource Potential by Technology (26-27 TPP)

Technology	PGE (GW)	SCE (GW)	SDGE (GW)
Utility-Scale Solar	147.5	153.4	57.8
Distributed Solar	11.8	20.3	4.5
Onshore Wind	3.0	4.7	2.6
Out-of-State Wind	4.3	15.0	-
Offshore Wind	28.9	-	-
In-State Geothermal	0.7	2.0	0.5
Out-of-State Geothermal	1.0	1.3	-
Biomass	1.0	0.1	0.1
Location-Constrained LDES (12-hr)	5.5	10.5	0.5
In-State Enhanced Geothermal	20.6	3.1	1.0
Out-of-State Enhanced Geothermal	2.9	6.8	-
Storage (Li-ion, LDES)	Uncapped	Uncapped	Uncapped
Thermal (CCGT, CT, Recip)	Uncapped	Uncapped	Uncapped

Enhanced Geothermal Resource Potential Totals

- EGS is assumed to be available for procurement in California, Oregon, Nevada, Idaho, and Utah
- For deep EGS, only the in-CAISO (including IID) 3-km potential will be used in IRP modeling; all out-of-state deep EGS (including Northeast CA) will be excluded
- The representation of deep EGS on transmission is expanded to represent the full locational dependency of the resource potential on the transmission system
- All non-CAISO EGS will incur additional transmission costs to deliver to the CAISO system

Resource Region	Near-Field EGS (MW)	Deep EGS (3 km) [1,2]
PG&E	668	15,461
SCE	2,025	1,115
SDGE	529	438
CAISO Total	3,224	17,016
Northeast CA[3]	178	4,264
Nevada[3]	4,364	Not modeled
Oregon[3]	1,893	Not modeled
Idaho[3]	1,872	Not modeled
Utah[3]	1,464	Not modeled

[1] In-state totals reflect amounts within 30 miles of electrical substation. Out-of-state totals reflect total potential.

[2] Based on the amount of Deep EGS potential at 3-km depth, and the incremental drilling costs to access EGS at deeper depths, only the Deep EGS potential at 3-km will be modeled in RESOLVE

[3] Transmission pathways for non-CAISO EGS are assumed to be identical to those for hydrothermal resources

Resource Cost Data Sources for the 2025 I&A

Technology	CAPEX	O&M	Tax Credit	Financing
Thermal (Gas CCGT, Gas CT, Reciprocating Engine)	NLR ATB, EIA AEO	NLR ATB, EIA AEO	none	NLR ATB, FRED, additional market data
Utility-Scale Solar PV	Custom analysis	NLR ATB	PTC	
Distributed Solar	NLR ATB	NLR ATB	ITC	
Onshore Wind	Custom analysis	NLR ATB	PTC	
Offshore Wind	NLR ATB	NLR ATB	ITC	
Geothermal (Conventional, Enhanced Geothermal Systems)	NLR ATB	NLR ATB	ITC	
Biomass	NLR ATB	NLR ATB	ITC	
Li-ion Battery	Custom analysis	NLR ATB	ITC	
Location-Constrained LDES	NLR ATB	NLR ATB	ITC	
Generic 12-hour LDES	PNNL ESGC	PNNL ESGC	ITC	
Generic 24-hour LDES	PNNL ESGC	PNNL ESGC	ITC	
Generic 100-hour LDES	LDES Council	LDES Council	ITC	

ESGC = Energy Storage Grand Challenge; FRED = Federal Reserve Economic Data

Appendix: Comparisons of Previous and Updated I&A

Candidate Resource Potential Changes Since Previous I&A

Resource	2022-2023 IRP Resource Potential (MW)	2024-2026 IRP Resource Potential (MW) - 2025 FR	2024-2026 IRP Resource Potential (MW) - 26-27 TPP	Notes
Solar	452,897	358,653	358,653	BLM WSP reduced potential
In-State Wind	11,424	11,191	10,344	CPA capacity factor data source updated
Out-of-State Wind	13,100 (through 2040) 52,113 (post-2040)	19,036	19,036	No longer assuming large wind + transmission potential increase in 2040
Offshore Wind	28,925	28,925	28,925	
Location-Constrained LDES	3,173	10,430	10,430	More potential projects included
Biomass	1,156	1,156	1,156	
Conventional Geothermal	5,522	5,554	5,554	Minor updates
Enhanced Geothermal (Near-Field)	Not modeled	12,992	12,992	
Enhanced Geothermal (Deep)	Not modeled	17,016	21,280	3 km depth only

Candidate Resource Available Year Changes Since Previous I&A

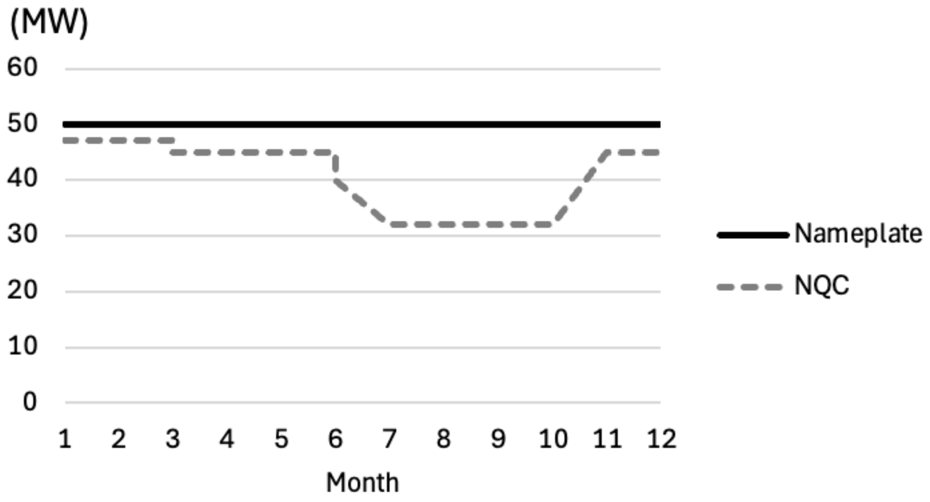
Resource	2022-2023 IRP First Available Year	2024-2026 IRP First Available Year	Notes
Solar	first model year (2024)	2026-2028	Near-term technology build limit raised from 9 GW to 12 GW
In-State Wind	2024-2031	2026-2035	Near-term technology and resource build limits through 2035
Out-of-State Wind	2026-2040	2026-2040	
Offshore Wind	2032-2039	2032-2040	
Location-Constrained LDES	2027-2031	2030-2037	Accounts for lead time
Li-ion Battery	first model year (2024)	first model year (2026)	
Generic LDES	Not Modeled	2031	
Biomass	2028	2028	
Conventional Geothermal	2026-2035	2026-2035	Near-term resource build limits through 2030 (in-state) or 2035 (out-of-state)
Enhanced Geothermal (Near-Field)	Not modeled	2030-2035	2030 (in-state) 2030-2035 (out-of-state)
Enhanced Geothermal (Deep)	Not modeled	2035	
Natural Gas	2029	2030	

NQC vs. Nameplate Accounting in the Baseline

- Many baseline units for hydro, geothermal, biomass, biogas, combined heat and power (CHP), and interruptible pumping demand response (DR) have varying monthly Net Qualifying Capacities (NQCs) listed by CAISO which may be considerably lower than their nameplate capacity as listed in the CAISO baseline data sources
- During the 2023 Preferred System Plan (PSP), the maximum capacity of these resources was reported at NQC; however, since then this has reverted to nameplate MW for consistency with other resources
- As a result of the baseline capacity for certain resources appears to have changed, but this only represents an accounting change and not actual capacity additions
  - This change did not impact any candidate resources

Nameplate MW Accounting	NQC MW Accounting (2023 PSP only)
• Capacity listed in RESOLVE is nameplate MW • Denominator in ELCC calculations is nameplate MW • Monthly dispatch limitations governed by NQC MW	• Capacity listed in RESOLVE is NQC MW • No additional ELCC derate*, since NQC is already derated • Monthly dispatch limitations governed by NQC MW

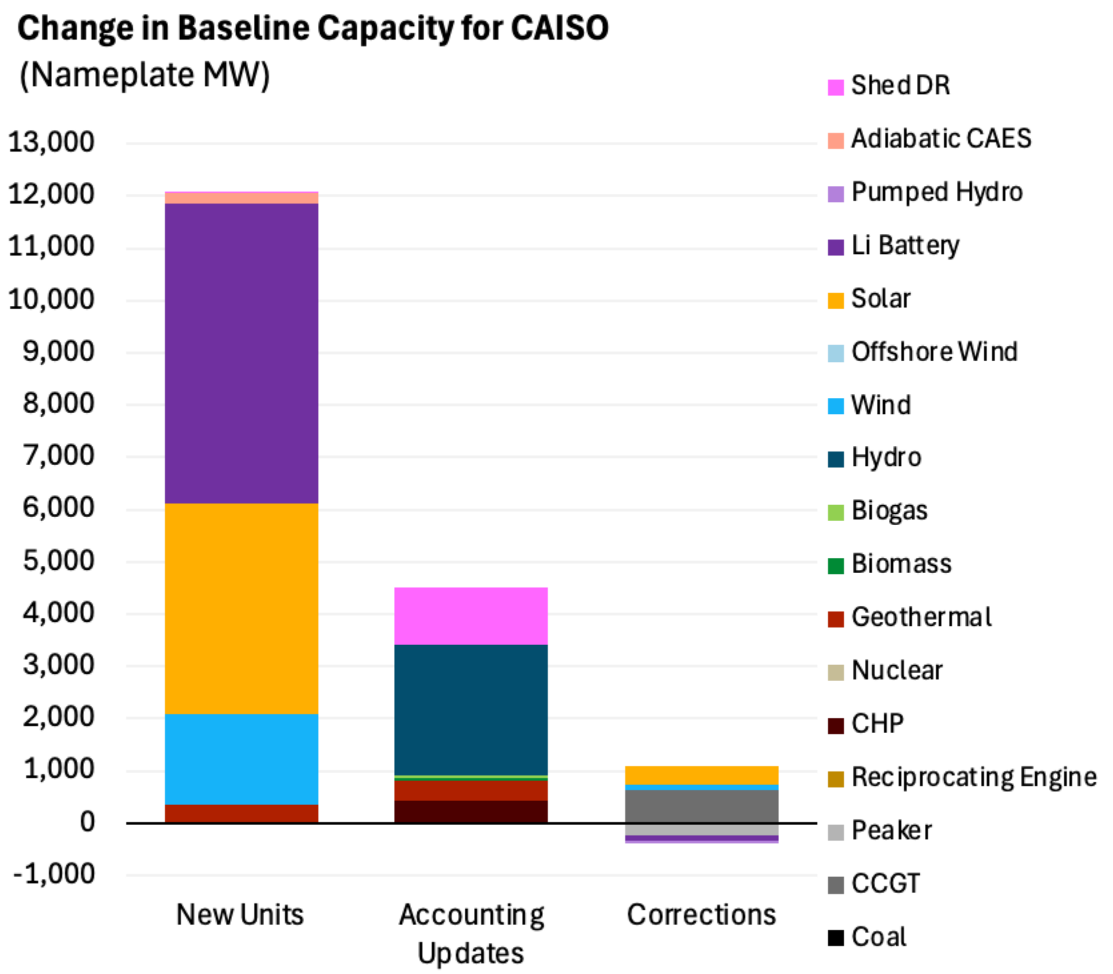
Illustrative NQC vs. Nameplate Capacity



*Challenges with ELCC accounting is the main driver for the return of accounting at the nameplate MW level

CAISO Baseline Changes Since Previous I&A

- Changes to CAISO baseline capacities are a mix of:
- **New Units** (~12 GW): new online and in-development units in CAISO since the creation of the 2023 (PSP) baseline, with CODs 2023-28
- **Accounting Updates** (~4.5 GW): resources reported at NQC in the previous I&A now reported at nameplate for consistency with other resources; this does not represent new capacity and does not impact total generation
  - Monthly NQCs are still applied for RESOLVE dispatch and calculations of ELCC
- **Corrections** (~<1 GW): small changes to existing units in the generator list to match the latest vintage of raw CAISO data



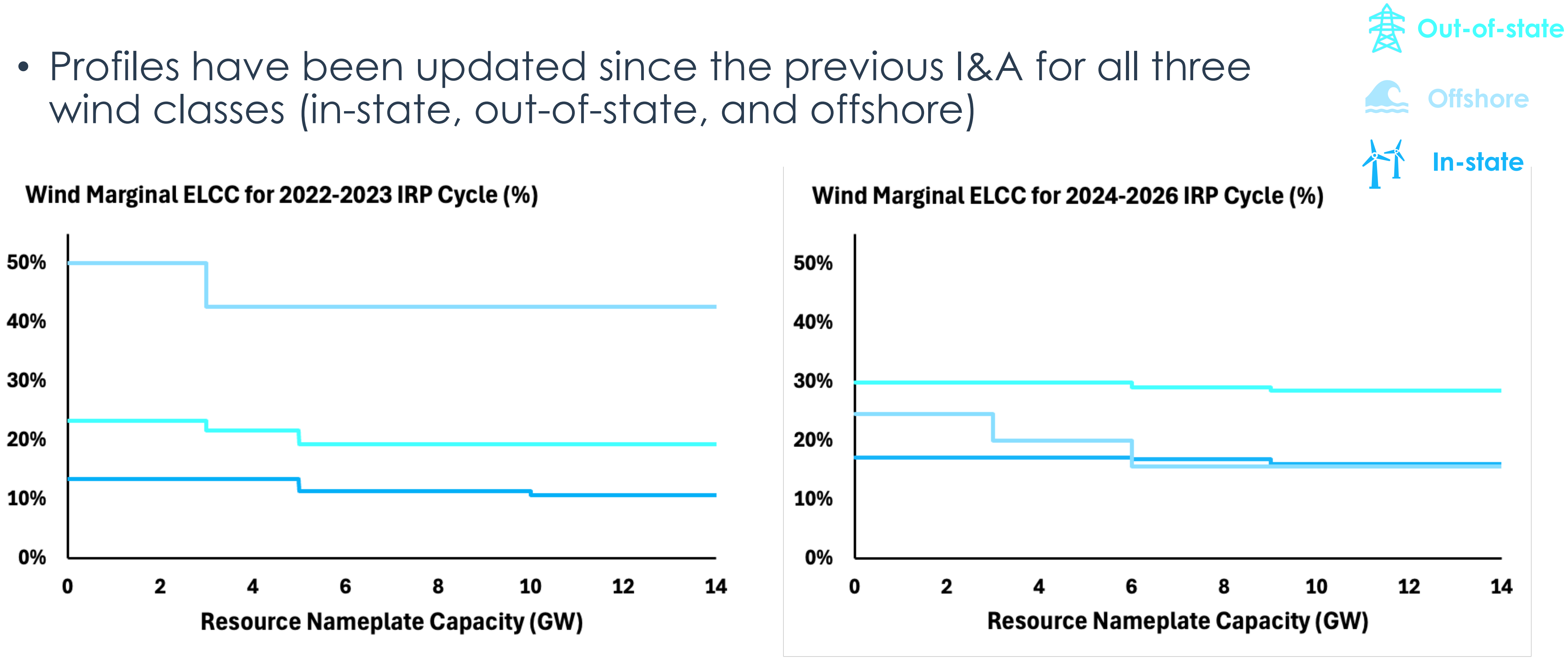
Static ELCC Changes Since Previous I&A

- Resources reported with capmax = NQC in the previous cycle did not have a separate ELCC applied, since the NQC already represented a derate
  - The table below shows ELCC for these resources as modeled in the past cycle (second column) and what the ELCC would be under the current methodology (third column)
- EFORd values used to allocate thermal ELCC across different classes drive key changes, such as lower Peaker ELCC

Resource Class	2022-2023 IRP ELCC as seen in Scenario Tool (% of NQC)	2022-2023 IRP ELCC (% of Nameplate)	2024-2026 IRP ELCC (% of Nameplate)	Notes
Biogas	*100%*	68.8%	72.9%	Capmax reported at NQC in previous cycle
Biomass	*100%*	70.4%	75.5%	Capmax reported at NQC in previous cycle
Combined Cycle	88.3%	88.3%	92.0%	
Combined Heat and Power (CHP)	*100%*	66.8%	70.2%	Capmax reported at NQC in previous cycle
Combustion Turbine (Peaker)	87.0%	87.0%	80.9%	
Geothermal	*100%*	81.8%	94.6%	Capmax reported at NQC in previous cycle
Nuclear	95.9%	95.9%	100%	
Reciprocating Engine	91.2%	91.2%	96.3%	
Existing DR + Pumping Loads	96.3%	60.1%	60.5%	Capmax reported at NQC in previous cycle
Hydro	64.6%	58.0%	55.8%	Capmax reported at NQC in previous cycle
Existing Pumped Hydro Storage	95.1%	95.1%	100%	Interactive effects with thermal & hydro assigned to PHS ELCC

Wind ELCC Changes Since Previous I&A

- Profiles have been updated since the previous I&A for all three wind classes (in-state, out-of-state, and offshore)

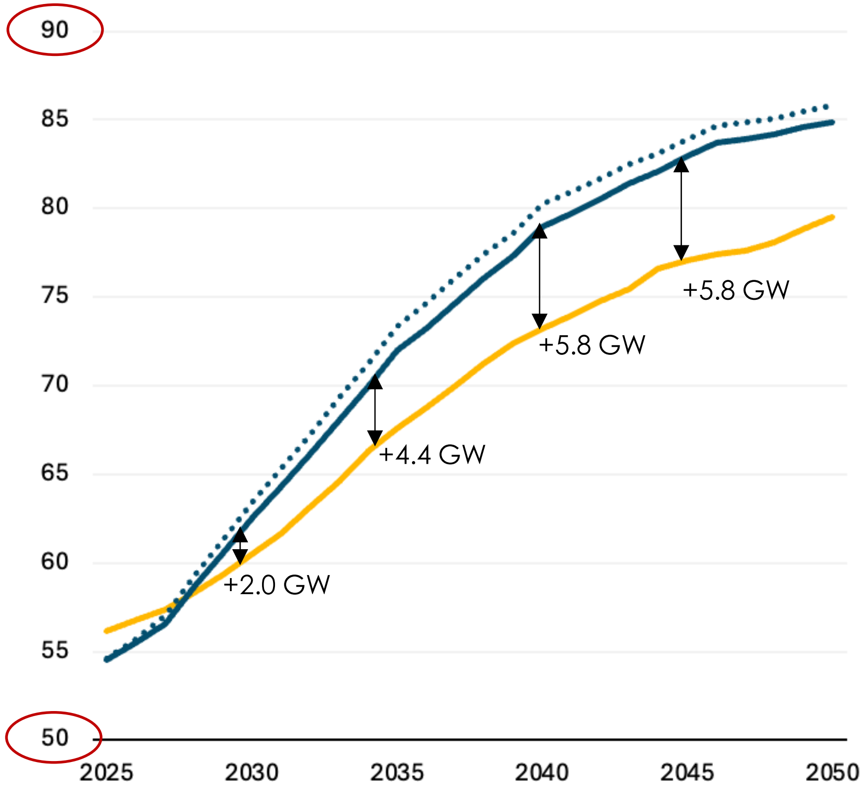


Appendix: Summary of the 2024 IEPR Load Forecast

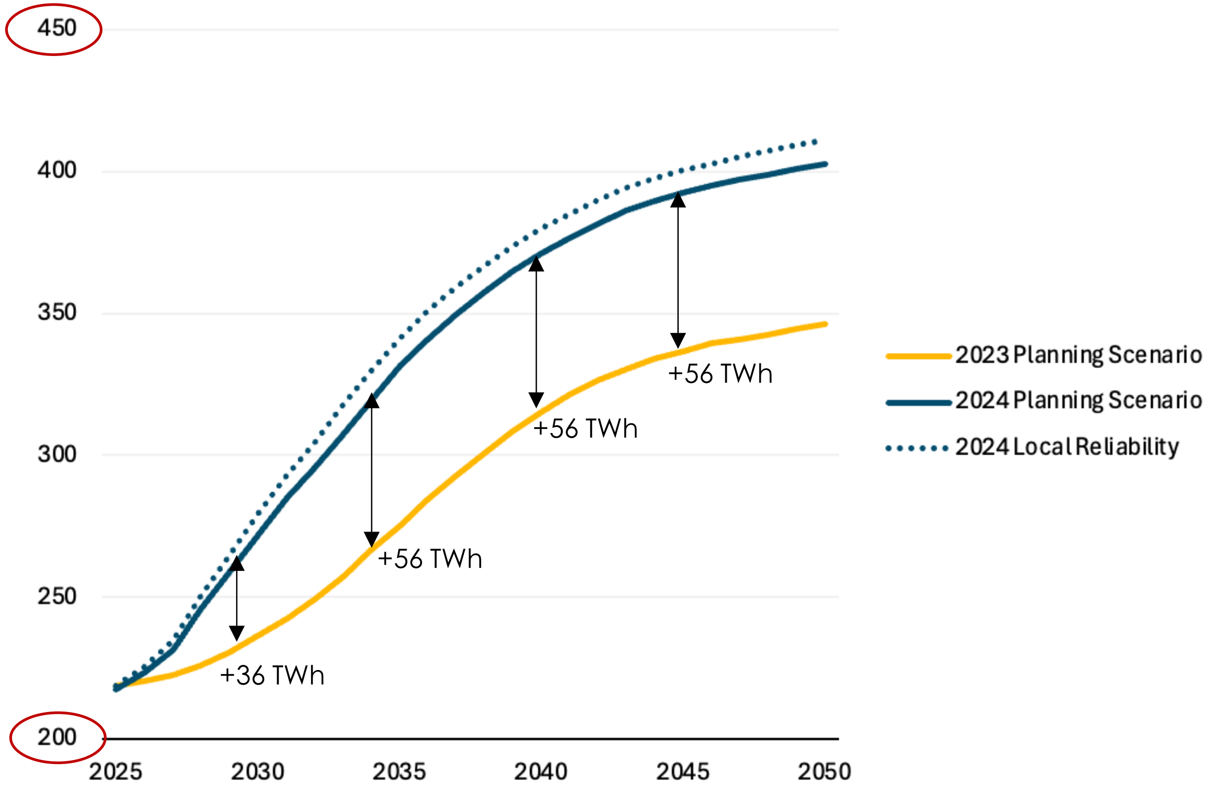
The 2024 IEPR Forecast Drives Additional Resource Needs

- Forecasts for both system peak and annual energy grow significantly in the 2024 IEPR, compared to the 2023 IEPR, driving increased capacity and GHG-free energy needs

Gross Peak for CAISO (GW)



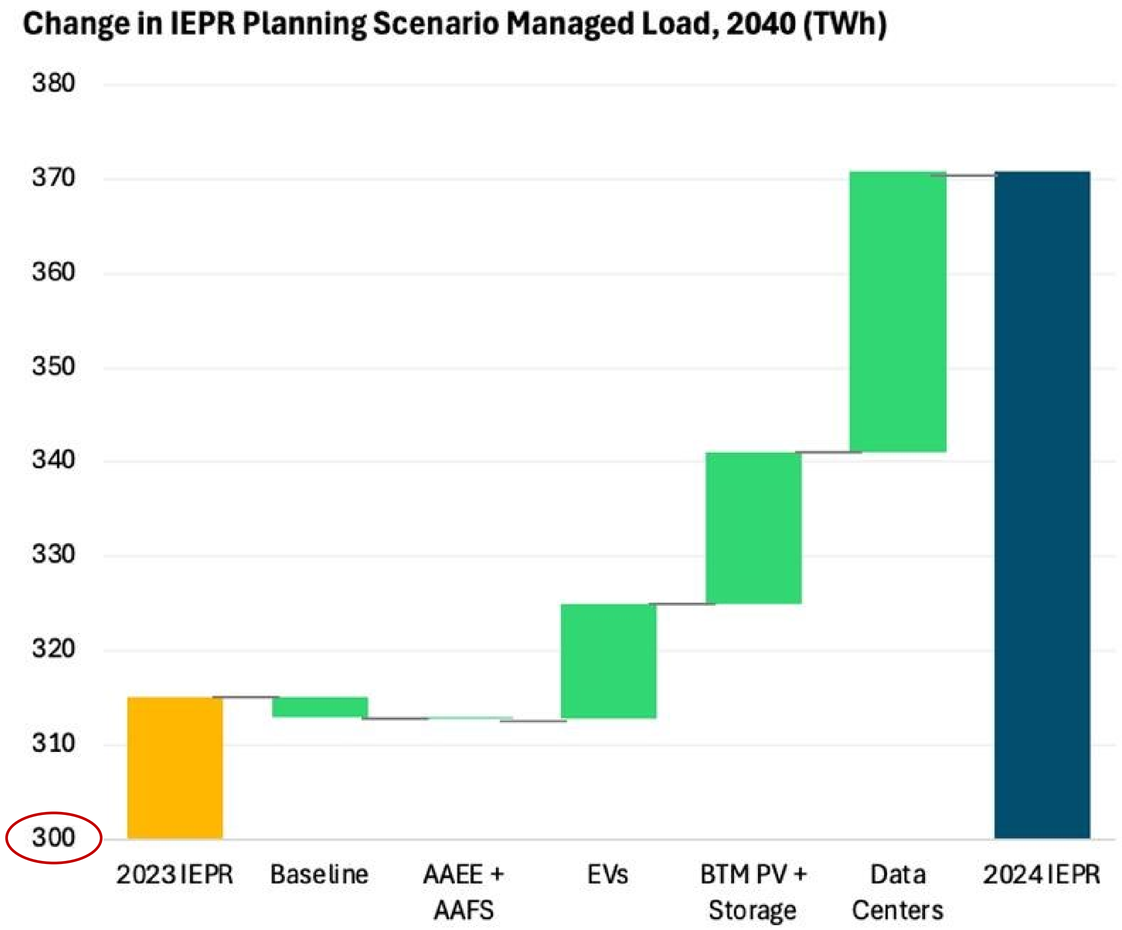
Managed Annual Load for CAISO (TWh)



Gross Peak is Managed Peak (sales & losses) + BTM PV. In RESOLVE, Gross Peak and Energy includes the effects of AAEE, AAFS, EV charging, climate change, data centers, and BTM storage. In SERVM, "consumption" peak and energy is modeled, separate from all the above load modifiers including BTM PV. All figures here assume no BTM CHP retirement. which is implemented as a change to baseline consumption in RESOLVE

2024 IEPR vs. 2023 IEPR: Managed Load Waterfall

- Increases in load are primarily driven by:
  - The introduction of significant data center loads in the 2024 IEPR by 2040
  - Less adoption and lower capacity factors for BTM Solar and Storage
  - Updates to electric vehicles, including higher vehicle miles travelled (VMT)
- Changes to the baseline, energy efficiency (AAEE), and building electrification (AAFS) are relatively small
  - In the 2030s, AAFS demand is higher in the 2024 IEPR, but is similar by 2040



Managed load = sales + losses

2024 IEPR Total Load by Component

- Baseline consumption remains the bulk of total load by 2040, but most growth is driven by electrification and data centers
  - Managed load grows by 157 TWh from 2024 to 2040; ~80% of this is driven by EVs, building electrification (AAFS), and data centers
  - BTM PV and energy efficiency (AAEE), which reduce load, grow more slowly
- By 2040, EVs grow to 23% of total managed load, followed by building electrification (10%) and data centers (8%)

Load Component	2024 Load	2040 Load	
Baseline	241 TWh	271 TWh	
Climate Impacts	~0	2 TWh	
Building Electrification (AAFS)	~0	37 TWh	
Baseline LDVs	1 TWh	37 TWh	EVs
Baseline MHDVs	~0	9 TWh	EVs
Policy-Driven (AATE) LDVs	~0	33 TWh	EVs
Policy-Driven (AATE) MHDVs	~0	7 TWh	EVs
Data Centers	1 TWh	30 TWh	
BTM Storage Losses	~0	<1 TWh	
BTM PV	-28 TWh	-45 TWh	
Energy Efficiency (AAEE)	-2 TWh	-11 TWh	
Total Managed Load	**214 TWh**	**371 TWh**	

Managed load = sales + losses; loads less than 0.2 TWh in 2024 are listed as ~0 (approximately zero)