# Inputs & Assumptions

2022-2023 Integrated Resource Planning (IRP)

October 2023

California Public Utilities Commission

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## List of Acronyms

| | |
|---|---|
| AAEE – Additional Achievable Energy Efficiency | LCR – Local Capacity Requirements |
| AAFS -- Additional Achievable Fuel Substitution | LCT -- Local Capacity Technical Study |
| AB -- Assembly Bill | LDES -- Long-Duration Energy Storage |
| A-CAES -- Adiabatic Compressed Air Energy Storage | LDV -- Light-Duty Vehicle |
| ADS -- Anchor Data Set | LOLE – Loss of Load Expectation |
| ATE -- Additional Transportation Electrification | LESR -- Limited Energy Storage Resource |
| BAA – Balancing Authority Area | LOLH – Loss of Load Hours |
| BANC -- Balancing Area of Northern California | LSE – Load Serving Entity |
| BNEF -- Bloomberg New Energy Finance | LTPP -- Long-Term Procurement Plan |
| BOEM -- Bureau of Ocean Energy Management | MAG -- Modeling Advisory Group |
| BTM – Behind the Meter | MERRA -- Modern-Era Retrospective-Analysis for Research and Applications |
| CAISO – California Independent System Operator | MMT -- Million Metric Tons |
| CAPEX -- Capital Expenditure | MTR -- Mid-Term Reliability |
| CAPMAX -- Maximum Capacity | MW – Megawatt |
| CARB -- California Air Resources Board | NAMGas -- North American Market Gas-Trade Model |
| CCA -- Community Choice Aggregator | NERC -- North American Electric Reliability Corporation |

| | |
|---|---|
| CCGT -- Combined Cycle Gas Turbine | NET -- Negative Carbon Emissions Technology |
| CCS -- Carbon Capture and Storage | NPV -- Net Present Value |
| CEC – California Energy Commission | NQC – Net Qualifying Capacity |
| CHP -- Combined Heat and Power (Cogeneration) | NREL ATB -- National Renewable Energy Laboratory Annual Technology Baseline |
| CPA -- Candidate Project Area | NREL SAM -- National Renewable Energy Laboratory System Advisor Model |
| CPP -- Critical Peak Pricing | OCS -- Outer Continental Shelf |
| CREZ -- Competitive Renewable Energy Zone | O&M -- Operations and Maintenance |
| CT -- Combustion Turbine | OOS -- Out-of-State |
| DAC -- Direct Air Capture | OTC -- Once-Through Cooling |
| D-CAES -- Diabetic Compressed Air Energy Storage | PCAP -- Perfect Capacity |
| DFA -- Development Focus Area | PCM -- Production Cost Model |
| DR -- Demand Response | PEM -- Proton Exchange Membrane |
| DRAM -- Demand Response Auction Mechanism | PPA -- Power Purchase Agreement |
| DRECP/SJV -- Desert Renewable Energy Conservation Plan / San Joaquin Valley | PRM – Planning Reserve Margin |
| EFORd -- Average Forced Outage Rate | PSP -- Preferred System Plan |
| EGS -- Enhanced Geothermal System | PTC -- Production Tax Credit |
| EIA -- Energy Information Administration | PU Code – Public Utilities Code |
| ELCC – Effective Load Carrying Capability | PV -- Photovoltaic Solar |
| EMS -- Energy Management System | RA – Resource Adequacy |
| EO -- Energy-Only Deliverability Status | R&D -- Research & Development |
| ESP -- Energy Service Provider | RETI -- Renewable Energy Transmission Initiative |
| EUE – Expected Unserved Energy | RPS -- Renewable Portfolio Standard |
| EV -- Electric Vehicle | SB -- Senate Bill |
| EVLST -- Electric Vehicle Load Shaping Tool | SERVM – Strategic Energy Risk Valuation Model |
| FCDS -- Full Capacity Deliverability Status | SMR -- Small Modular Nuclear Reactor |
| FERC -- Federal Energy Regulatory Commission | SNG -- Synthetic Natural Gas |

| | |
|---|---|
| FSSAT -- Fuel Substitution Scenario Analysis Tool | SOD - Slice of Day |
| GADS – Generator Availability Data System | SSN -- Secondary System Need |
| GHG -- Greenhouse Gas | ST -- Steam Turbine |
| HEIAWG -- Interagency Working Group High Electrification Scenario | STR -- Storage |
| HSN -- Highest System Need | SUN – Solar PV |
| IAWG -- Interagency Working Group | TAC – Transmission Access Control |
| ICAP -- Installed Capacity | TEPPC -- Transmission Expansion Planning Policy Committee |
| IEA -- International Energy Agency | TID -- Turlock Irrigation District |
| IEPR – Integrated Energy Policy Report | TOU -- Time-of-Use |
| IID -- Imperial Irrigation District | TPP -- Transmission Planning Process |
| IMF -- International Monetary Fund | TRN -- Total Reliability Need |
| IOU -- Investor-Owned Utility | Tx -- Transmission |
| IPP -- Independent Power Producer | UCAP – Unforced Capacity |
| IRA -- Inflation Reduction Act | USGS -- U.S. Geological Survey |
| IRR -- Internal Rate of Return | VEA -- Valley Electric Association |
| ITC -- Investment Tax Credit | VGI -- Vehicle-Grid Integration |
| LADWP or LDWP -- Los Angeles Department of Water and Power | V1G -- VGI shifting load |
| LBNL -- Lawrence Berkeley National Laboratory | V2G -- VGI discharging to the grid |
| LCOE -- Levelized Cost of Energy | WECC – Western Electricity Coordinating Council |
| LCOS -- Levelized Cost of Storage | WRF -- Weather Research and Forecasting Model |

# 1. Introduction

This document describes the key data elements and sources of inputs and assumptions for the California Public Utilities Commission's (CPUC's) 2022-2023 Integrated Resource Planning (2022-2023 IRP) modeling. It also summarizes the methodology for how different data components are used to develop the 2022-2023 IRP Preferred System Portfolio.

The inputs, assumptions, and methodologies are applied to create optimal portfolios for the CAISO electric system that reflect different assumptions regarding load growth, technology costs and potential, fuel costs, and policy constraints. In some cases, multiple options are included for use in developing IRP scenarios and sensitivities modeling.

## 1.1 Overview of the RESOLVE model

The high-level, long-term identification of new resources that meet California's policy goals is directly informed by use of the RESOLVE resource planning model. The CPUC uses RESOLVE to develop the Load Serving Entities (LSE) Filing Requirements, a look into the future that identifies a portfolio of new and existing resources that meets the Greenhouse Gas (GHG) emissions planning constraint, provides ratepayer value, and responds to reliability needs. The CPUC uses RESOLVE because it is a publicly available and vetted tool. The CPUC uses the process of soliciting party feedback on inputs and assumptions to ensure that RESOLVE contains transparent, publicly available data sources and transparent methodologies to examine the long-term planning questions posed within the Integrated Resource Planning process.

RESOLVE is formulated as a linear optimization problem. It co-optimizes investment and dispatch for a selected set of days over a multi-year horizon to identify least-cost portfolios for meeting carbon emission reduction targets, renewables portfolio standard goals, reliability during peak demand events, and other system requirements. RESOLVE typically focuses on developing portfolios for one zone, in this case the CAISO Balancing Authority Area, but incorporates a representation of neighboring zones in order to characterize transmission flows into and out of the region of interest. Zone in this context refers to a geographic region that consists of a single balancing authority area (BAA) or a collection of BAAs in which RESOLVE balances the supply and demand of energy. The CPUC IRP version of RESOLVE includes seven zones: four zones capturing California balancing authorities, two zones that represent regional aggregations of out-of-state balancing authorities, and one resource-only zone representing dedicated hydroelectric imports from the Pacific Northwest.[1] The CAISO zone in RESOLVE represents the CAISO balancing authority area.

RESOLVE can solve for optimal investments in new candidate resources, as well as economic retention of existing resources. Resources and asset types include:

- Thermal generators (e.g., gas, geothermal, biomass)
- Renewable resources
- Energy storage
- Hydropower
- Shift & shed demand response, energy efficiency, and other distributed energy resources (e.g., BTM PV)
- Intra- and inter-zonal transmission
- Electrolytic fuels
- Negative emissions technologies (e.g., direct air capture)

Subject to the following constraints:

- Hourly zonal demand and operating reserve requirements.
- An annual constraint on delivered renewable energy and zero-carbon energy that reflects Renewables Portfolio Standard (RPS) policy and the Senate Bill (SB) 100 policy.
- An annual constraint on emissions (e.g., GHGs).
- An annual Planning Reserve Margin (PRM) constraint to maintain resource adequacy and reliability.
- Technology-specific operational constraints (e.g., ramp rate limits, battery state-of-charge); and
- Constraints on the minimum retention amounts for gas-fired thermal resources, representing resources in local capacity requirement (LCR) areas.
- Constraints on the ability to develop specific new resources.
- Constraints on transmission line upgrade limits

RESOLVE optimizes the buildout of new resources years into the future, representing the fixed costs of new investments and the costs of operating the CAISO system within the broader footprint of the Western Electricity Coordinating Council (WECC) electricity system.

[1] A seventh resource-only zone was added in the 2019-2021 IRP to simulate dedicated imports from Pacific Northwest hydroelectric resources. This zone does not have any load and does not represent a BAA.

## 1.2 Overview of the SERVM Model

The CPUC also uses the Strategic Energy Risk Valuation Model (SERVM) as a separate tool to provide more detailed analysis of factors such as system reliability once a portfolio has been determined. SERVM calculates numerous reliability and cost metrics for a given study year in light of expected weather, overall economic growth, electric demand and resource generation, and unit performance. For each of these factors, variability and forecasting uncertainties are also taken into account. An individual year is simulated many times over, with each simulation reflecting a slightly different set of weather, economic, and unit performance conditions. In contrast to RESOLVE, the entire year is simulated, and daily and seasonal patterns are analyzed. Probability-weighted expected values are then created from model outputs which reflect twenty-three possible weather years, five points of load forecast error, and many unit outage draws, creating thousands of iterations for the simulation.

The results provide a comprehensive distribution of reliability costs, expected unserved energy, and other reliability metrics. Energy Division staff uses these metrics to determine the adequate quantity of effective capacity required to maintain a target Loss of Load Expectation (LOLE).

The 2022-2023 IRP cycle includes activities to align the inputs and outputs of RESOLVE and SERVM, to the extent possible, through the use of common data sources to achieve reasonable agreement in outputs between the models.

## 1.3 Document Contents

The remainder of this document is organized as follows:

- **Section 2 (Load Forecast)** documents the assumptions and corresponding sources used to derive the forecast of load in CAISO and the WECC, including the impacts of demand-side programs, load modifiers, and the impacts of electrification.
- **Section 3 (Baseline Resources)** summarizes assumptions on baseline resources. Baseline resources are existing or in development resources that are assumed to be operational in the year being modeled.
- **Section 4 (Resource Cost Methodology)** describes the financial model used to calculate levelized fixed costs of candidate resources in RESOLVE.
- **Section 5 (Optimized Resources)** discusses assumptions used to characterize the potential new resources that can be selected for inclusion in the optimized, least-cost portfolio. Candidate resources are incremental to baseline resources.
- **Section 6 (Generators Operating Assumptions)** presents the assumptions used to characterize hourly electricity demand and the operations of each of the resources represented in RESOLVE's internal hourly production simulation model.

- **Section 7 (Resource Adequacy Requirements)** discusses the constraints imposed on the RESOLVE portfolio to ensure system and local reliability needs are met, as well as assumptions regarding the contribution of each resource towards these requirements.
- **Section 8 (Greenhouse Gas Emissions and Renewables Portfolio Standard)** discusses assumptions and accounting used to characterize constraints on portfolio greenhouse gas emissions and renewables portfolio standard targets.

## 1.4 Key Data and Model Updates

Since the publication of the "Inputs & Assumptions: 2019-2021 Integrated Resource Planning"[2] in November 2019, CPUC staff and its consultant Energy and Environmental Economics, Inc. (E3) implemented numerous updates to RESOLVE and SERVM model functionality, inputs, and assumptions.

Key updates to RESOLVE include:

- Updating the RESOLVE model code base to improve customization of inputs, model flexibility, and implementation of emerging technologies.
- Updating both models to align with the CEC 2022 Integrated Energy Policy (IEPR) California Energy Demand Forecast Update (Section 2).
- Updating the Baseline Resource assumptions to the most recent data available on existing and planned resources including new additions within and outside of CAISO (Section 3).
- Updating the methodology for creating resource costs for all new candidate resources (Section 4).
- Updating the environmental screens, resource potential and geographic area of all renewable resources (Section 5.2).
- Updating candidate resource-transmission deliverability constraint representation, the methodology and values for the transmission deliverability, including the ability to reflect technology-specific and location-specific transmission utilization factors, and the transmission upgrade availability, limits, and costs (Sections 5.2.1 and 5.5).
- Updating the geographic granularity of the solar candidate resources (Section 5.2.1)
- Adding transmission deliverability utilization for pumped storage and battery storage resources (Section 5.3).

[2] Found at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2021-irp-events-and-materials/inputs--assumptions-2019-2021-cpuc-irp_20191106.pdf

- Adding geographic granularity to the battery storage candidate resources (Section 5.3.2).
- Adding near-term deployment limits for Candidate Solar, Battery Storage and Shed DR resources (Sections 5.2.2, 5.3.2, and 5.6.1).
- Updating the alignment of modeled reliability needs and methodology with the Mid-Term Reliability Decision D.21-06-035[3] and the Reliability Filing Requirements for Load Serving Entities' 2022 Integrated Resource Plans[4].

Key updates to SERVM include:

- Staff performed extensive updates to the generating fleet in SERVM, aligning with the January 2023 CAISO Master Generating Capability List and expected development resources included in LSE IRP filings from November 1, 2022.
- Staff performed extensive calibration with the latest 2032 WECC ADS, including new generators that are now planned to come online, retiring, and removing failed or old generation that is no longer projected to be online, and updating electric demand peak and energy forecast for regions outside California.
- Staff simplified the representation of external areas to California by reducing the number of external areas included from 15 to the 7 nearest ones.
- Updated weather data to include solar, wind and electric demand data for 2018-2020 to go with the previous set from 1998-2017.
- Decoupled hydroelectric scenarios from electric demand, wind and solar to create a wider range of variability. In short, instead of 23 weather years (1998-2020) times five load forecast uncertainty levels for 115 total cases, now inputs have 23 weather years, 23 hydroelectric scenarios, and five load forecast uncertainty points, totaling 2,645 cases.
- Refined wind and electric demand shapes to align with latest weather data. Wind shapes were migrated from being based on the MERRA dataset to the WRF dataset.
- Revised hydroelectric shapes based on recent hourly and monthly data collected from CAISO, BPA, and EIA.
- Updated electric demand forecast and emissions prices according to the CEC 2022 IEPR California Energy Demand Forecast Update.

[3] Found at:
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF

[4] Found at:
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/20220616-irp-lse-plan-prm-study-results.pdf

- Updated fuel prices to draft 2023 NAMGas model forecast provided by the CEC.

# 2. Load Forecast

## 2.1 CAISO Balancing Authority Area

The primary source for CAISO load forecast inputs, for both peak and energy demand, is the CEC's Integrated Energy Policy Report (IEPR) Demand Forecast Update.[5] CEC's 2022 IEPR load forecast scenarios will be primarily used in modeling. Specifically, the 2022 IEPR Planning Scenario[6] will be used in core modeling and the 2022 IEPR Local Reliability Scenario will also be implemented for potential sensitivity analysis. The 2021 High Electrification IAWG (HEIAWG) scenario baseline load forecast is used to complement the baseline for 2022 IEPR for the years not covered in the 2022 IEPR data. Therefore, there will be no need for the use of other studies (such as previously used CEC's 2018 Deep Decarbonization in a High Renewable Future report) for long-term load forecast.[7] Table 1 presents an overview of different 2021 and 2022 IEPR scenarios, where each row represents a distinct load component.

[5] Most of the demand data were extracted from IEPR Forms 1.1c, 1.5a, 1.5b, and 1.2. 2021 IEPR workbooks, including the breakdown of demand and demand modifier components for the CAISO area, hourly profiles, and installed capacity for BTM resources, were used to develop inputs for RESOLVE modeling.

[6] The 2022 Integrated Energy Policy Report, https://www.energy.ca.gov/event/workshop/2022-12/iepr-commissioner-workshop-updates-california-energy-demand-2022-2035-0?utm_medium=email&utm_source=govdelivery

[7] Note that although the formally adopted IAWG's High Electrification Scenario has energy forecasts only through 2035, in 2022, CEC provided data to CPUC for this scenario that covers a longer-term forecast through 2050; and therefore, these data were used to inform long-term load forecasts needed for the 2045 modeling timeframe.

*Table 1. 2022 IEPR Planning, 2021 IEPR, 2021 HEIAWG, and 2021 ATE scenario description.*

| Load Component | 2022 IEPR Planning Scenario | 2022 IEPR Local Reliability Scenario | 2021 IEPR-Mid | 2021 High Electrification IAWG (HEIAWG) | 2021 ATE Scenario |
|---|---|---|---|---|---|
| Baseline Demand Case | Mid Case | Mid Case | Mid Case | Mid Case | Mid Case |
| Transportation Scenario | AATE Scenario 3 | Scenario 3 | Mid Case | Policy | 2021-2027: Mid case<br>2028-2035: Policy |
| AAEE Scenario | Scenario 3 | Scenario 2 | Scenario 3 | Scenario 4 | Scenario 3 |
| AAFS Scenario | Scenario 3 | Scenario 4 | Scenario 3 | Scenario 4 | Scenario 3 |
| CARB SIP NOx Rules (FSSAT) | Excluded | Included in AAFS | Excluded | Included | Excluded |

Many components of the CEC IEPR demand forecast are broken out so that the distinct hourly profile of each of these factors can be represented explicitly in modeling. The components are referred to in this document as "demand-side modifiers." Hourly profiles for demand-side modifiers are discussed in Section 6.2.1.

Demand-side modifiers include the following categories and the data sources for each are discussed in subsequent sections:

- Electric vehicles
- Building electrification
- Other electrification
- Behind-the-meter (BTM) PV
- Non-PV self-generation (predominantly behind-the-meter combined heat and power)
- Energy efficiency
- Time of use (TOU) rate impacts

Demand forecast inputs are frequently presented as demand at the customer meter. However, our planning models measure demand at the generator busbar. Consequently, demand forecasts at the customer meter are grossed up for transmission and distribution losses. Average losses across the CAISO zone calculated from CEC's 2021 IEPR Demand Forecast data are 7.35%, but losses calculated from the 2022 IEPR forecast are 7.97%, about 0.6% higher. Therefore, the RESOLVE model will use a loss rate of 7.97% when modeling the 2022 IEPR Scenarios, but 7.35% will be used when modeling the 2021 ATE (and any load components derived from it) or 2021 IEPR Mid scenarios, for consistency.

### 2.1.1 Baseline Consumption

Baseline consumption captures economic and demographic changes in California. In RESOLVE and SERVM the baseline peak and total energy consumption forecast is derived from total retail sales reported in the CEC's demand forecast data along with accompanying information on the magnitude of demand-side modifiers and behind-the-meter-generation forecast data. In both models, the energy consumption forecasts remove the effects of demand modifiers and demand-side generation that are explicitly modeled; in SERVM this is also reflected in the peak energy consumption. These components are: additional achievable energy efficiency (AAEE)[8], additional achievable fuel substitution (AAFS), BTM PV, BTM storage, TOU rates effects, and light, medium, and heavy-duty electric vehicle charging. In RESOLVE additional components include BTM CHP and Other Self-generation. The various components of the baseline consumption forecast are shown in Table 2.

[8] AAEE refers to efficiency savings beyond current committed programs.

*Table 2. Baseline Consumption from the 2022 IEPR Planning Scenario Demand Forecast (GWh)*

| Component | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| 2022 IEPR Retail Sales | 204,446 | 206,747 | 212,740 | 220,236 | 246,153 | 265,798 | 286,082 |
| - Light-Duty EVs[9] | 4,531 | 6,344 | 10,984 | 17,166 | 38,968 | 58,831 | 76,055 |
| - Medium/Heavy Duty EVs[10] | 572 | 944 | 2,011 | 3,300 | 8,795 | 14,526 | 19,956 |
| - AAFS | 1,530 | 1,891 | 2,666 | 3,511 | 5,589 | 6,236 | 6,970 |
| + AAEE | 4,467 | 5,593 | 7,692 | 9,722 | 14,097 | 15,186 | 16,571 |
| + Behind-the-Meter PV | 29,045 | 31,042 | 35,213 | 39,496 | 50,059 | 60,622 | 71,185 |
| - Storage Losses | 82 | 105 | 152 | 200 | 331 | 461 | 592 |
| - TOU Effects | 36 | 38 | 42 | 47 | 58 | 69 | 81 |
| **= Baseline Consumption** | 231,209 | 234,060 | 239,790 | 245,230 | 256,570 | 261,483 | 270,184 |

[9] See Figure 21 of the *Final 2022 Integrated Energy Policy Report Update* for associated vehicle adoption forecast https://efiling.energy.ca.gov/GetDocument.aspx?tn=250084

[10] See Figure 22 of the *Final 2022 Integrated Energy Policy Report Update* for associated vehicle adoption forecast https://efiling.energy.ca.gov/GetDocument.aspx?tn=250084

### 2.1.2 Transportation Electrification

Both 2022 IEPR Scenarios include baseline transportation electrification and use Scenario 3 for additional achievable transportation electrification (the sum of both components is shown in in Table 3). The 2022 IEPR transportation electrification forecast will primarily be used for modeling. Additionally, there are two other transportation load options available from the 2021 vintage including 2021 IEPR-Mid and the 2021 ATE. Similar options are available for medium and heavy-duty vehicles as well. The 2021 IEPR scenarios included electrification of "other" end uses (e.g., ports, and airport ground equipment); however, the 2022 IEPR transportation has only two components of light and medium/heavy duty EV (Table 4).

*Table 3. Light-duty electric vehicle forecast options (GWh)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2022 IEPR Planning Scenario and Local Reliability[11] | 4,531 | 6,344 | 10,984 | 17,166 | 38,968 | 58,831 | 76,055 |

[11] See Figure 21 of the *Final 2022 Integrated Energy Policy Report Update* for associated vehicle adoption forecast https://efiling.energy.ca.gov/GetDocument.aspx?tn=250084

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CEC 2021 IEPR – Mid[12] | 8,823 | 10,073 | 12,365 | 14,952 | 21,915 | 26,200 | 30,485 |
| CEC 2021 ATE | 8,823 | 10,073 | 13,830 | 23,059 | 57,487 | 97,269 | 118,007 |

*Table 4. Medium and heavy-duty electric vehicle forecast options (GWh)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2022 IEPR Planning Scenario and Local Reliability[13] | 572 | 944 | 2,011 | 3,330 | 8,795 | 14,526 | 19,956 |
| CEC 2021 IEPR – Mid Demand[14] | 560 | 824 | 1,441 | 2,220 | 4,623 | 9,202 | 13,782 |
| CEC 2021 ATE | 560 | 824 | 1,986 | 3,512 | 8,090 | 10,932 | 14,123 |

*Table 5. Other transport electrification forecast options (GWh)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2022 IEPR Planning Scenario | Included with the medium/heavy duty EV loads | | | | | | |

[12] See Figure 36 of the *Final 2021 Integrated Policy Report, Volume IV: California Energy Demand Forecast* for underlying vehicle adoption assumptions. https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581

[13] See Figure 21 of the *Final 2022 Integrated Energy Policy Report Update* for associated vehicle adoption forecast https://efiling.energy.ca.gov/GetDocument.aspx?tn=250084

[14] See Figure 38 of the *Final 2021 Integrated Policy Report, Volume IV: California Energy Demand Forecast* for underlying vehicle adoption assumptions. https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CEC 2021 IEPR – Mid Demand | 298 | 352 | 454 | 563 | 865 | 6,968 | 13,070 |
| CEC 2021 ATE | 298 | 352 | 454 | 563 | 865 | 1,183 | 1,500 |

### 2.1.3 Building Electrification

The building sector's electrification load is modeled with AAFS. CEC's 2022 IEPR Planning Scenario that uses Mid forecasts (Scenario 3) will be modeled in the core modeling; however, 2022 Local Reliability Scenario forecasts that include higher building electrification loads (Scenario 4) might be used for potential sensitivity analysis.[15] [16]

*Table 6. AAFS forecast options for the building sector (GWh)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2022 IEPR Planning Scenario | 1,530 | 1,891 | 2,666 | 3,511 | 5,589 | 6,236 | 6,971 |
| CEC 2022 IEPR Local Reliability Scenario | 1,629 | 2,726 | 6,227 | 11,419 | 25,199 | 34,001 | 39,824 |

[15] See Chapter 3 of the *Final 2022 Integrated Energy Policy Report Update* for description of the building electrification scenarios in the 2022 IEPR https://efiling.energy.ca.gov/GetDocument.aspx?tn=250084

[16] See Chapter 2 of the *Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast* f or description of the building electrification scenarios in the 2021 IEPR https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CEC 2021 IEPR – Mid Demand | 1,257 | 1,620 | 2,400 | 3,254 | 5,452 | 20,278 | 35,103 |
| CEC 2021 ATE | 1,257 | 1,620 | 2,400 | 3,254 | 5,452 | 7,185 | 8,039 |

### 2.1.4 Behind-the-Meter PV

There are two forecasts for BTM PV generation based on 2021 CEC data and 2022 CEC data presented in Table 7.[17] The generation data are calculated from IEPR hourly data.[18] In SERVM, the geographically granular breakdown of BTM PV generation and capacity by CEC Forecast Zones is used.[19] In RESOLVE, the energy generation and capacities are aggregated to CAISO level. For years that 2022 IEPR data are not available, data are extrapolated linearly. These forecasts exclude the impacts of net-energy-metering regulation changes.

*Table 7. Behind-the-meter PV forecast options (GWh)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2022 IEPR Planning Scenario and Local Reliability Scenario | 29,045 | 31,042 | 35,213 | 39,496 | 50,059 | 60,622 | 71,185 |
| CEC 2021 (IEPR-Mid and ATE) | 28,373 | 30,460 | 34,813 | 39,286 | 50,396 | 60,380 | 71,225 |

### 2.1.5 Behind-the-meter CHP and Other Non-PV Self Generation

The forecast of non-PV self-generation is based on the CEC 2022 IEPR Demand Forecast through 2035 and the additional data that CEC provided for long-term modeling in the 2021 HEIAWG. On-site combined heat and power (CHP) that does not export to the grid makes up the majority

[17] Additional forecast options will be considered for the Final version of this document to enable potential sensitivity analyses.
[18] Link to 2022 IEPR Planning Scenario https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359
[19] Link to BTM PV capacity is available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=243188&DocumentContentId=76885

of this component. Because emissions from BTM CHP are counted towards total electric sector emissions, the portion of BTM CHP is separated from the total non-PV self-generation. CHP units that export energy to the grid are separately discussed in Section 3.1. Forecasts for BTM CHP and the remaining non-PV non-CHP self-generation are shown in the tables below. Two BTM CHP forecasts are considered for 2022 forecasts: one that assumes BTM CHP remains online through 2045 (similar to the 2021 ATE scenario) and the other that assumes BTM CHP retires by 2040 (similar to the 2021 IEPR Mid) for 2022 IEPR forecasts. It is also assumed that BTM CHP retires linearly between 2035 and 2040. Forecast of non-PV self-generation is the same across IEPR Scenarios.

*Table 8. Forecast of Behind-the-meter CHP (GWh)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| BTM CHP Not Retired | 12,061 | 11,958 | 11,756 | 11,558 | 10,991 | 10,436 | 9,881 |
| BTM CHP Retired by 2040 | 12,061 | 11,958 | 11,756 | 11,558 | 10,991 | 0 | 0 |

*Table 9. Forecast of other non-PV on-site self-generation (GWh)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2021 IEPR and 2022 IEPR | 361 | 373 | 396 | 419 | 398 | 378 | 358 |

### 2.1.6 Energy Efficiency

Varying levels of energy efficiency achievement among CAISO load-serving entities are available in the modeling. While the mid-level AAEE forecast in the CEC's 2021 IEPR-Mid scenario will be preserved in the model, the 2022 IEPR Planning scenario is included to be used in the core modeling cases. Additionally, lower AAEE forecasts are available in the 2022 Local Reliability Scenario. CEC published forecasted data for AAEE scenarios through 2050, which was used to complement the formally adopted 2022 IEPR scenario for years of 2036-2035.

*Table 10. Energy efficiency forecast options (GWh)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2022 IEPR Planning Scenario | 4,467 | 5,593 | 7,692 | 9,722 | 14,097 | 15,186 | 16,571 |
| CEC 2022 IEPR Local Reliability Scenario | 3,230 | 3,872 | 5,048 | 6,185 | 8,681 | 9,047 | 9,630 |
| CEC 2021 IEPR – Mid | 4,217 | 5,350 | 7,464 | 9,513 | 14,031 | 21,355 | 28,679 |
| CEC 2021 ATE | 4,217 | 5,350 | 7,464 | 9,513 | 14,031 | 30,920 | 34,054 |

### 2.1.7 Time-of-Use Rate Impacts

Impacts of time-of-use (TOU) rate implementation on retail load are represented in two different options. The first option assumes no impact to load shape. The second corresponds to mid residential TOU scenarios with two forecasted scenarios available from CEC's 2021 and 2022 IEPR Demand Forecast through 2035 followed by flat growth in later years (the forecasts round up close to each other). As modeled, TOU rates modify the hourly load profile but have little impact on annual load.

*Table 11. Residential TOU rate implementation load impacts (GWh)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2022 IEPR Planning Scenario and Local Reliability Scenario | 36 | 38 | 42 | 47 | 58 | 58 | 58 |
| CEC 2021 IEPR – Mid | 36 | 38 | 43 | 47 | 58 | 58 | 58 |
| None | - | - | - | - | - | - | - |

## 2.2 CAISO Balancing Authority Area – Peak Demand

### 2.2.1 Introduction

The magnitude and timing of managed peak demand of the system can significantly impact resource portfolio selection by increasing the value of resources that can produce energy during managed peak periods. The managed peak demand is determined by total energy demand, demand-side modifiers, BTM generation, and underlying demand profiles though it is not itself specifically input into the model.

### 2.2.2 Gross System Peak

In RESOLVE, gross system peak is calculated directly from CEC IEPR hourly demand data for CAISO as the annual peak of hourly "managed net load" (inclusive of "VEA load") minus hourly "BTM PV" generation demand reduction.[20] RESOLVE instead models BTM PV as a supply-side resource in both hourly dispatch and resource adequacy. RESOLVE assigns an ELCC value to BTM PV to determine its contribution to the numerator of RESOLVE's PRM constraint. Additionally, in RESOLVE modeling, two alternatives are considered for BTM and front-of-meter CHP units; one that assumes CHPs remain online (as assumed for BTM CHPs in the IEPR load forecasts) and the other that assumes CHPs retire by 2040. Thus, for the latter case, gross peak is adjusted for BTM CHP peak impacts for the 2036-2045 timeline. This adjustment is made by assuming a flat profile for BTM CHP generation.

[20] BTM storage is treated as load modifier because its dispatch profiles from IEPR show negligible impact on system peak.

Gross system peak as defined in RESOLVE is applied to the PRM percentage resulting in the total system perfect capacity need determination.

In SERVM, gross system peak is also derived directly from CEC IEPR hourly demand data but is input to SERVM at the IOU planning area level rather than the CAISO as a whole. It is defined as the annual peak of IOU planning area hourly “managed net load” minus hourly demand increases or decreases from BTM PV, AAEE, AAFS, BTM storage, EV charging, and TOU rates. These demand modifiers are separately input to SERVM. As a final step, the SERVM gross system peak inputs of each IOU planning area are calibrated such that the managed net peak of the CAISO as a whole matches that of the CEC’s IEPR.

*Table 12. CAISO gross system peak forecast in RESOLVE*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2022 IEPR Planning Scenario | 54,199 | 54,880 | 56,472 | 58,289 | 64,028 | 68,746 | 74,074 |
| CEC 2022 IEPR Planning Scenario: BTM CHP Retire by 2040 | 54,199 | 54,880 | 56,472 | 58,289 | 64,028 | 70,032 | 75,292 |
| CEC 2022 Local Reliability Scenario | 54,473 | 55,369 | 57,554 | 60,168 | 67,922 | 72,207 | 77,967 |
| CEC 2022 Local Reliability Scenario: BTM CHP Retire by 2040 | 54,473 | 55,369 | 57,554 | 60,168 | 67,922 | 73,493 | 79,185 |
| CEC 2021 IEPR – Mid | 54,241 | 54,899 | 56,259 | 57,592 | 60,952 | 63,880 | 66,807 |
| CEC 2021 ATE | 54,241 | 54,899 | 56,560 | 58,898 | 66,609 | 75,049 | 81,640 |

### 2.2.3 Managed Net Peak

The annual CAISO managed net peak forecasts were calculated using the CEC 2022 and 2021 scenarios hourly load data and are shown in in Table 13 for selected years. In RESOLVE, the maximum hourly load in each year (through 2050) was found and reported as managed net peak (inclusive of VEA hourly load.) It is notable that managed net peak is not used for reliability need determination and has no impact on RESOLVE optimization for a least cost resource portfolio.

In SERVM, electric demand peak and energy and demand modifiers are explicitly modeled for each of the three IOU planning areas within CAISO (PGE, SCE, and SDGE). SERVM inputs by planning area are calibrated such that the managed peak of the CAISO as a whole matches with the CEC's IEPR forecasted managed peak for CAISO.

*Table 13. CAISO managed net peak forecast in RESOLVE.*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CEC 2022 IEPR Planning Scenario | 47,988 | 48,488 | 49,828 | 51,292 | 55,117 | 57,598 | 60,836 |
| CEC 2022 IEPR Planning Scenario: BTM CHP Retire by 2040 | 47,988 | 48,488 | 49,828 | 51,292 | 55,117 | 58,884 | 60,836 |
| CEC 2022 IEPR Local Reliability Scenario | 48,244 | 48,954 | 50,890 | 53,175 | 59,107 | 63,028 | 67,184 |
| CEC 2022 Local Reliability Scenario: BTM CHP Retire by 2040 | 48,244 | 48,954 | 50,890 | 53,175 | 59,107 | 64,314 | 67,184 |
| CEC 2021 IEPR – Mid | 47,862 | 48,305 | 49,387 | 50,394 | 52,568 | 55,495 | 58,422 |
| CEC 2021 ATE | 47,862 | 48,305 | 49,540 | 51,146 | 55,638 | 63,334 | 63,334 |

## 2.3 Other Zones

RESOLVE and SERVM both use a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes seven zones: four zones capturing California balancing authorities (Balancing Authority of Northern California (BANC), California Independent System Operator (CAISO), Los Angeles Department of Water and Power (LADWP), and Imperial Irrigation District (IID)), two zones that represent regional aggregations of out-of-state balancing authorities, and one resource-only zone.[21] The constituent balancing authorities included in each RESOLVE zone are shown in Table 78 (Section 6.5).

Demand forecasts for zones outside CAISO are taken from two sources and are presented in Table 14:

- For each of the zones within California (LADWP, BANC, and IID) but external to CAISO,[22] total energy to serve load forecasts are taken from the CEC's 2022 IEPR Planning Forecast Form 1.5a. For the years 2036 and beyond, load is extrapolated using average annual growth rate in the last three years.
- For the zones outside of California (the Pacific Northwest and the Southwest), WECC's 2032 Anchor Data Set (ADS) PCM V2.3.2 Public Dataset[23] is used as the basis for load projections. Sales forecasts net of demand-side modifiers are combined with available information in the ADS related to demand-side modifier and consumption forecasts to reconstitute the consumption forecasts for each region. This data is then aggregated to the RESOLVE zones. The demand forecasts are then grossed up for transmission and distribution losses.

*Table 14. Non-CAISO Net Energy for Load – grossed up for T&D losses (GWh)*

| RESOLVE Zone | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| NW | 186,251 | 188,254 | 193,179 | 195,823 | 208,042 | 223,183 | 238,323 |
| SW | 116,841 | 119,797 | 125,105 | 128,722 | 141,277 | 155,679 | 170,081 |
| LDWP | 26,157 | 26,313 | 27,110 | 28,420 | 33,612 | 39,306 | 45,000 |
| IID | 4,021 | 4,046 | 4,103 | 4,145 | 4,227 | 4,298 | 4,368 |
| BANC | 20,010 | 20,172 | 20,633 | 21,200 | 22,856 | 24,577 | 26,298 |

SERVM's representation of non-CAISO regions is similar but more geographically granular. Consistent with RESOLVE, SERVM's non-CAISO California load forecasts are drawn directly from the CEC's 2022 IEPR. Forms 1.2 and 1.5 and demand modifier hourly and/or annual data by IEPR Planning Area or Forecast Zone were used to develop SERVM's inputs. SERVM also employs a more granular zonal transmission topology than RESOLVE, modeling 7 regions within California

[21] The RESOLVE model includes an additional resource-only zone to simulate dedicated Pacific Northwest Hydro imports. This zone does not have any load and is not included here.
[22] See for Section 6.7 for details on the zonal topology used in RESOLVE.

[23] Data available on WECC website: https://www.wecc.org/ReliabilityModeling/Pages/AnchorDataSet.aspx

plus the 7 nearest external regions. The loads for regions external to California were updated to draw from the 2032 Anchor Data Set, like RESOLVE.

*Table 15. Zonal transmission topology and load regions represented in RESOLVE and SERVM*

| RESOLVE Zone | SERVM Regions |
|---|---|
| NW | BPAT, PACW, PortlandGE |
| SW | AZPS, NEVP, SRP, WALC |
| LDWP | LADWP |
| IID | IID |
| BANC | SMUD, TID |
| CAISO | PGE, SCE, SDGE |

## 3. Baseline Resources

Baseline resources are resources that are currently online or are contracted to come online within the planning horizon. Being "contracted" refers to a resource holding signed contract(s) with an LSE(s). The contracts refer to those approved by the CPUC and/or the LSE's governing board, as applicable. These criteria indicate the resource is relatively certain to come online.

The capacity of **baseline** resources is an input to capacity expansion modeling, as opposed to **candidate** resources, which are selected by the model and are incremental to the baseline. For some resources, baseline resource capacity is reduced over time to reflect announced retirements. An estimation of baseline resource capital costs is used when calculating total revenue requirements and electricity rates.

Baseline resources include:

- Existing resources: Resources that have already been built and are currently available, net of expected future retirements.
- Resources under development: Resources that have contracts approved by the CPUC or the board of a community choice aggregator (CCA) or energy service provider (ESP).
- Resources under development in non-CAISO balancing areas: IRP modeling does not optimize resource additions for balancing areas outside CAISO, but changes in the generation portfolio of balancing areas outside of CAISO may influence portfolio selection within the CAISO area. Consequently, in-development resources are added to other balancing areas to contribute to policy and reliability targets outside of CAISO.

Baseline resources are assembled from the primary sources listed in Table 16 and are further described below.

*Table 16. Data Sources for Baseline Resources*

| Zone | Online Status | Generator type | Dataset used |
|---|---|---|---|
| In CAISO | Existing | Renewable, Storage, and Non-Renewable | CAISO Master Generating Capability List, CAISO Master File |
| In CAISO | In-development | Renewable and Storage | November 2022 LSE IRP filings, including IRP data for CAISO POUs processed by CEC. These are tagged as "Development" in the RDT.<br>RPS Contract Database and data requests |
| In CAISO | In- development | Non-Renewable | November 2022 LSE IRP filings, including IRP data for CAISO POUs processed by CEC. These are tagged as "Development" in the RDT.<br>WECC ADS |
| Out of CAISO | Existing and In-development | Renewable, Storage and Non-Renewable | WECC ADS, with supplemental data from non-CAISO California POU IRPs and independent studies for SB100 compliance[24,25,26,27] |
| In CAISO and Out of CAISO | Retirement Dates | Renewable, Storage and Non-Renewable | Updated CAISO Mothball/Retirement list,<br>November 2022 LSE IRP filings, including IRP data for CAISO POUs processed by CEC.<br>WECC ADS |

- The list of generators currently operational to serve CAISO is compiled from the CAISO Master Generating Capability List as of January 2023[28]. These generators serve load inside CAISO and are composed of renewable and non-renewable generation resources, as well as some demand response resources. The CAISO Master Generating Capability List information is supplemented by the CAISO Master File, a confidential data set with unit-specific operational attributes. Both lists also include information related to dynamically scheduled generators, which are physically located outside of the CAISO but

[24] LADWP – LA 100 Study, available at [LA100: The Los Angeles 100% Renewable Energy Study and Equity Strategies]
[25] SMUD – 2030 Zero Carbon Plan, available at [SMUD 2030 Zero Carbon Plan Technical Report]
[26] IID – CEC Review of IID 2018 IRP, available at https://efiling.energy.ca.gov/getdocument.aspx?tn=230474
[27] TID – CEC Review of TID 2018-2030 IRP, available at https://www.energy.ca.gov/filebrowser/download/1905
[28] Available at: http://oasis.caiso.com/mrioasis/logon.do

can participate in the CAISO market as if they were internal to CAISO. However, because they have no obligation to sell into CAISO they are modeled as unspecified imports and do not have special priority given to their energy dispatch.

- Future generators that will serve IOU-related CAISO load are compiled from the November 1st, 2022, version of IRP Filings, which list contracts entered into by LSEs and approved by the LSEs' highest decision-making authority as of August 1, 2022. This information is supplemented by data requests from CCAs and ESPs within the Procurement Track. To the extent that any of these resources came online between August 1, 2022 and the publishing of the January 2023 CAISO Master Generator Capability List, the CAISO information is used instead.
- For generators outside of CAISO, including areas within California such as LADWP and SMUD, generator listings and their associated operating information are taken from the most current version of the WECC's 2032 Anchor Data Set (ADS) v2. For LADWP, BANC, and IID, additional solar resources are added to the portfolio if TEPPC ADS renewable resources fall short of the amount of renewable generation needed under a 60% RPS by 2030.

## 3.1 Natural Gas, Coal, and Nuclear Generation

### 3.1.1 Modeling Methodology

Natural gas, coal, and nuclear resources are represented in RESOLVE by a limited set of resource classes by zone, with operational attributes set at the capacity weighted average for each resource class in that zone. The capacity weighted averages are calculated from individual unit attributes available in the CAISO Master File or the WECC ADS. The following resource classes are modeled: Nuclear, Coal, Combined Cycle Gas Turbine (CCGT), Gas Steam, Peaker, Reciprocating Engine, and Combined Heat and Power (CHP).

To reflect different classes of gas generators in the CAISO zone, CAISO's gas generators are further divided into subcategories. These subcategories are based on natural breakpoints in operating efficiency observed in the distribution of data within class averages:

- The CCGT generator category is divided into two subcategories based on generator efficiency: higher efficiency units are represented as **"CAISO_CCGT1"** and lower efficiency units are represented as **"CAISO_CCGT2"**. The division into subcategories does not consider the age of each unit, as there is no real correlation between age and efficiency. Additionally, two generators that are located outside of CAISO, but contracted to import energy to CAISO, are represented as **"CAISO_CCGT_Remote"**.

- The Peaker generator category is the aggregation of natural gas frame and aeroderivative technologies and is divided into two subcategories: higher efficiency units are represented as **"CAISO_Peaker1"** and lower efficiency units are represented as **"CAISO_Peaker2"**. There is not a strong correlation between the efficiency and age of Peaker units.
- The **"CAISO_ST"** generator category represents the existing fleet of steam turbines, all of which are scheduled to retire by default at the end of 2023 to achieve compliance with the State Water Board's Once-Through-Cooling (OTC) regulations.
- The **"CAISO_Reciprocating_Engine"** generator category represents existing gas-fired reciprocating engines on the CAISO system.
- The **"CAISO_CHP"** generator category represents non-dispatchable cogeneration facilities with thermal hosts, which are modeled to provide around-the-clock power production at a constant level in RESOLVE.

The capacity of fossil-fueled and nuclear thermal generators that have formally announced retirement, including the Diablo Canyon Nuclear Power Plant, are removed from baseline thermal capacity using the announced retirement schedule.

### 3.1.2 Economic Retention

In consistency with the update made during the 2019-2021 IRP, the RESOLVE model preserves the functionality to determine the optimal level of dispatchable gas resources to retain resources that minimizes overall CAISO system costs but still attains other resource planning objectives such as reliability and GHG reductions.

Fixed operations and maintenance (fixed O&M) costs of baseline gas-fired resources are considered in RESOLVE's optimization logic such that dispatchable gas generators will only be retained by the model, subject to reliability constraints, if it is cost-effective to do so. In the 2019-2021 IRP cycle, fixed O&M costs for both existing (baseline) and new (candidate) gas resources were derived from National Renewable Energy Lab (NREL) Annual Technology Baseline (ATB). It is believed that fixed O&M costs for gas generators in the current NREL ATB (2022), which are representative of current and recent commercial offerings,[29] are lower than industry data for existing, older gas generators. For this reason, CEC's *Estimated Cost of New*

[29] See NREL 2022 ATB webpage on fossil energy technologies: https://atb.nrel.gov/electricity/2022/fossil_energy_technologies.

*Utility-Scale Generation in California: 2018 Update*,[30] which carries higher estimates for gas fixed O&M costs than NREL 2022 ATB, is chosen to represent the fixed O&M costs of existing gas generators in RESOLVE in the 2022-23 IRP (Table 17). This CEC report was used in CPUC's 2021 study *Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning* and aligns with ongoing fixed O&M costs for the existing gas fleet based on other E3 analyses.[31] NREL ATB is used for fixed O&M costs for new (candidate) gas resources, as described in Section 5.1. The following considerations are made in economic gas fleet retention modeling:

- Retention decisions are made for CCGTs, Peakers, and Reciprocating Engines.
- Gas resources located in local areas are assumed to serve local capacity requirements; up to 4 GW of these resource may be retired and replaced with 4-hour Li-ion batteries, but the remaining 15 GW must be retained to maintain local reliability (Section 7.2.1)
- While combined heat and power (CHP) facilities are retained indefinitely economically due to the presence of a thermal host, they are assumed to be phased out by 2040.
- OTC plants (CAISO_ST) are retired on a pre-determined schedule. Retention decisions for these plants are not made by RESOLVE.

*Table 17. Fixed O&M costs for baseline gas resources (2022 $)*

| Resource Type | Fixed O&M Cost ($/kW-yr) |
|---|---|
| CAISO_Peaker_1, CAISO_Peaker_2<br>CAISO_Reciprocating_Engine<br>CAISO_ST | $38.74 |
| CAISO_CCGT_1<br>CAISO_CCGT_2<br>CAISO_CCGT_Remote | $48.68 |

Note that RESOLVE's thermal economic retention functionality assesses whether it is economic to retain gas capacity for CAISO ratepayers but does <u>not</u> assess whether gas capacity should

[30] Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning. CPUC Staff Paper. October 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2021-irp-events-and-materials/cpuc-gas-upgrades-staff-paper-october-2021.pdf.
[31] Found here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2021-irp-events-and-materials/cpuc-gas-upgrades-staff-paper-october-2021.pdf

retire. Other offtakers may contract with gas plants balanced by CAISO, even if CAISO ratepayers do not. In addition, gas plant operators may choose to keep plants online without a long-term contract.

### 3.1.3 CAISO Resources

Baseline natural gas, coal, and nuclear resources serving CAISO load are drawn from a combination of the CAISO Master Generating Capability List and the CAISO Master File. Planned new generation for the CAISO area is taken from the LSE IRP plans.

*Table 18. Baseline Conventional Resources in the CAISO balancing area (MW)*

| Resource Class | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| CHP* | 1,914 | 1,914 | 1,933 | 1,933 | 967 | - | - |
| Nuclear** | 635 | 635 | 635 | 635 | 635 | 635 | 635 |
| CCGT1 | 14,352 | 14,352 | 14,352 | 14,352 | 14,352 | 14,352 | 14,352 |
| CCGT2 | 2,528 | 2,528 | 2,528 | 2,528 | 2,528 | 2,528 | 2,528 |
| CCGT_Remote | 648 | 648 | 648 | 648 | 648 | 648 | 648 |
| Coal | - | - | - | - | - | - | - |
| Peaker1 | 2,668 | 2,668 | 2,668 | 2,668 | 2,668 | 2,668 | 2,668 |
| Peaker2 | 5,536 | 5,536 | 5,536 | 5,536 | 5,536 | 5,536 | 5,536 |
| Reciprocating Engine | 259 | 259 | 259 | 259 | 259 | 259 | 259 |
| ST | - | - | - | - | - | - | - |
| **Total** | **29,105** | **29,105** | **29,124** | **29,124** | **29,124** | **29,124** | **29,124** |

**The remaining CHP units by 2030 are assumed to decommission at a linear rate, with no generators remaining by 2040.*

***Diablo Canyon units are assumed to retire in 2024 and 2025. The share of Palo Verde Nuclear Generating Station capacity contracted to CAISO LSEs is included in all years and is modeled within CAISO in RESOLVE. After retirement of Diablo Canyon in 2025, all remaining CAISO nuclear capacity is from Palo Verde.*

### 3.1.4 Other Zones Resources

For zones external to the CAISO, the baseline gas, coal, and nuclear generation fleet is based on the WECC 2032 ADS. The ADS is used to characterize the existing and anticipated future generation fleet in each non-CAISO zone. The ADS uses utility integrated resource plans to inform changes in the generation portfolio, including announced retirements of coal generators and near-term planned additions.

*Table 19. Baseline conventional resources in external zones (MW)*

| Zone | Resource Class | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| **NW** | Nuclear | 1,170 | 1,170 | 1,170 | 1,170 |
| | Coal | - | - | - | - |
| | CCGT | 7,470 | 7,470 | 7,470 | 7,470 |
| | Peaker | 1,071 | 1,071 | 1,071 | 1,071 |
| | **Subtotal, NW** | **9,711** | **9,711** | **9,711** | **9,711** |
| **SW** | Nuclear | 2,998 | 2,998 | 2,998 | 2,998 |
| | Coal | 3,282 | 3,014 | 1,377 | 1,377 |
| | CCGT | 17,188 | 17,188 | 16,600 | 15,945 |
| | Peaker | 4,449 | 4,427 | 4,427 | 3,671 |
| | ST | 757 | 523 | 523 | 523 |
| | **Subtotal, SW** | **28,691** | **28,149** | **25,925** | **24,514** |
| **LDWP** | Nuclear | 407 | 407 | 407 | 407 |
| | Coal | - | - | - | - |
| | CCGT | 3,047 | 4,053 | 4,052 | 4,052 |
| | Peaker | 1,154 | 1,154 | 1,154 | 1,154 |
| | ST | 99 | 99 | 99 | 99 |
| | **Subtotal, LDWP** | **4,650** | **5,873** | **5,873** | **5,873** |
| **IID** | CCGT | 442 | 442 | 442 | 442 |
| | Peaker | 252 | 342 | 342 | 342 |
| | **Subtotal, IID** | **694** | **784** | **784** | **784** |
| **BANC** | CCGT | 1,587 | 1,522 | 1,522 | 1,522 |
| | Peaker | 888 | 888 | 888 | 888 |
| | **Subtotal, BANC** | **2,475** | **2,410** | **2,410** | **2,410** |

## 3.2 Renewables

Baseline renewable resources include all existing RPS eligible resources (solar, wind, biomass, geothermal, and small hydro) in each zone. Renewable resources with contracts already approved by the CPUC, CCA boards, or ESP boards (which includes those under development), are accounted for in the baseline as well. All wind in the baseline is onshore.

Baseline behind-the-meter solar capacity is discussed in Sections 2.1.4 above.

### 3.2.1 CAISO Renewable Resources

CAISO baseline renewable resources include (1) existing resources, whether under contract or not, and (2) resources that have executed contracts with LSEs. As described above, information on existing renewable resources within CAISO is compiled from the CAISO Master Generating Capability List and the CAISO Master File.

Information on resources that are under development with approved contracts is compiled from the CPUC IOU contract database and LSE IRP plans (most recently submitted and analyzed on November 1, 2022). The CPUC maintains a database of all the IOUs' active and past contracting activities for renewable generation. Utilities submit monthly updates to this database with changes in contracting activities. Renewable contract information obtained from data requests to CCAs, and ESPs is used to supplement the CPUC IOU contract database. The baseline renewable resource capacity in CAISO is shown in Table 20.

*Table 20. Baseline Renewables in CAISO (MW)*

| Resource Class | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| Hydro* | 6,662 | 6,662 | 6,662 | 6,662 | 6,662 | 6,662 | 6,662 |
| Biomass | 487 | 487 | 487 | 486 | 486 | 438 | 438 |
| Biogas | 217 | 217 | 217 | 217 | 209 | 209 | 209 |
| Geothermal | 1,303 | 1,343 | 1,397 | 1,397 | 1,397 | 1,397 | 1,397 |
| Solar | 19,037 | 19,037 | 19,037 | 19,037 | 19,037 | 19,037 | 19,037 |
| Wind | 7,713 | 7,789 | 7,789 | 7,789 | 7,789 | 7,789 | 7,789 |
| **Total** | **35,419** | **35,535** | **35,589** | **35,588** | **35,588** | **35,540** | **35,540** |

**Includes both large and small hydro generating units. The percentage of generation attributable to small hydro, which can generate RECs, is handled in RPS accounting. Also, CapMax values are the monthly July totals from the 1998 weather year. RESOLVE and SERVM use historical monthly weather profiles from 1998 – 2020 to determine energy production from hydro resources.*

A subset of the resources shown in Table 20 have an Energy-Only Deliverability status, as opposed to Full Capacity Deliverability Status (FCDS). The capacity of the energy-only resources is shown in Table 21.

*Table 21. Baseline Energy-only Renewables in CAISO (MW)*

| Resource Class | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| Biomass | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Solar | 1,596 | 1,596 | 1,596 | 1,596 | 1,596 | 1,596 | 1,596 |
| Wind | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| **Total** | **1,603** | **1,603** | **1,603** | **1,603** | **1,603** | **1,603** | **1,603** |

### 3.2.2 Other Zones Renewable Resources

#### *3.2.2.1 Other California Entities*

For non-CAISO entities in California (those in the balancing authority areas IID, LADWP or BANC), the renewable resource portfolio is derived from the 2032 WECC ADS. The 2019-2021 IRP cycle assumes that entities in each of the non-CAISO BAAs in California comply with the current RPS statute (60% RPS by 2030 and interim targets before 2030).[32] If renewable resources in the WECC ADS are not sufficient to ensure RPS compliance, utility-scale solar resources are added to fill the renewable net short. RPS-compliant resource portfolios are developed outside of RESOLVE and input to the model – RESOLVE does not optimize renewable resource capacity for non-CAISO BAAs. Baseline renewable capacities for other California entities are shown in Table 22.

*Table 22. Baseline Renewables in Other California Entities (MW)*

| Zone | Resource Class | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| BANC | Biomass | 1 | 1 | 1 | 1 |
| | Biogas | 18 | 18 | 18 | 18 |
| | Geothermal | 70 | 70 | 70 | 70 |
| | Hydro | 2,040 | 2,040 | 2,040 | 2,040 |
| | Solar | 488 | 488 | 488 | 488 |
| | Wind | 430 | 430 | 430 | 430 |
| | **BANC Total** | **3,046** | **3,046** | **3,046** | **3,046** |
| IID | Biomass | 77 | 77 | 77 | 77 |
| | Biogas | 15 | 15 | 15 | 15 |
| | Geothermal | 563 | 607 | 607 | 607 |
| | Hydro | - | - | - | - |
| | Solar | 546 | 546 | 546 | 546 |
| | Wind | - | - | - | - |
| | **IID Total** | **1,201** | **1,245** | **1,245** | **1,245** |
| LDWP | Biomass | - | - | - | - |
| | Biogas | 4 | 4 | 4 | 4 |
| | Geothermal | 151 | 151 | 151 | 151 |
| | Hydro | 1,005 | 1,005 | 1,005 | 1,005 |
| | Solar | 2,432 | 2,462 | 2,462 | 2,462 |
| | Wind | 424 | 424 | 424 | 424 |
| | **LDWP Total** | **4,015** | **4,045** | **4,045** | **4,045** |

[32] SB 100 was signed into law on September 10, 2018. SB 100 establishes a new RPS target of 60% by 2030. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

### *3.2.2.2 Non-California LSEs*

The portfolios of renewable resources in the NW and SW are based on WECC's 2032 Anchor Data Set, developed by WECC staff with input from stakeholders. Some of the resources in the ADS that are located outside of California represent resources under long-term contract to California LSEs. Since these resources are captured in the portfolios of CAISO and other California LSEs, they are removed from the baseline resource capacity of the non-California LSEs. Baseline renewable capacities for non-California LSEs are shown in Table 23. The BAAs covered within the NW and SW zones are defined in Table 78.

*Table 23. Baseline Renewables in non-California LSEs (MW)*

| Zone | Resource Class | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| NW | Biomass | 786 | 732 | 732 | 732 |
| | Biogas | 39 | 39 | 38 | 38 |
| | Geothermal | 4 | 24 | 24 | 24 |
| | Solar | 1,895 | 3,040 | 3,065 | 3,065 |
| | Wind | 7,237 | 8,192 | 8,642 | 8,642 |
| | **NW Total** | **9,961** | **12,026** | **12,499** | **12,499** |
| SW | Biomass | 16 | 16 | 16 | 16 |
| | Biogas | 38 | 38 | 26 | 26 |
| | Geothermal | 1,190 | 1,260 | 1,260 | 1,260 |
| | Solar | 9,198 | 9,748 | 12,100 | 12,100 |
| | Wind | 776 | 911 | 911 | 911 |
| | **SW Total** | **11,217** | **11,972** | **14,312** | **14,312** |

Resources that have a contract to supply RECs to a CAISO LSE but are not dynamically scheduled into CAISO are modeled as supplying RECs to CAISO RPS requirements, but energy from these projects is added to the local zone's energy balance. The list of these resources is shown in Table 24.

*Table 24.Renewable plants outside of CAISO attributed to CAISO loads.*

| Generator Name | Capacity Contracted to CAISO (MW) |
|---|---|
| ArlingtonWind | 103 |
| Big_Horn_Wind_1_2 | 105 |
| BigHorn2 | 17 |
| Horseshoe_Bend_Wind | 145 |
| JuniperCanyon1 | 5 |
| Klondike_Wind_1_2 | 24 |
| Klondike_Wind_III_1 | 90 |
| NipponBiomass | 20 |
| North_Hurlburt_Wind | 133 |
| PebbleSprings | 20 |
| RooseveltBioCC_Total | 26 |
| South_Hurlburt_Wind | 145 |
| Vantage | 96 |
| MIDWYS_2_MIDSL1 | 50 |
| Salton_Sea_5 | 50 |
| Second_Imperial01_12 | 33 |
| Milford_Wind_1_1 | 5 |
| Luning_Solar | 55 |
| TURQ_GEN | 10 |

## 3.3 Large Hydro

The existing large hydro resources in each zone of RESOLVE and SERVM are assumed to remain unchanged over the timeline of the analysis. The large hydro resources in RESOLVE and SERVM are represented as providing energy to their local zone, with the exception of Hoover, which is split among the CAISO, LADWP, and SW zones in proportion to ownership shares.

A fraction of the total Pacific Northwest hydro capacity is made available to CAISO as a directly scheduled import. Specified hydro imports from the Pacific Northwest were included in RESOLVE as a reduction in annual electricity supply GHG emissions of 2.8 MMT. For the 2022-2023 IRP cycle, RESOLVE modeling will use the same methodology as the 2019-2021 IRP, where specified imports of hydro power from the Pacific Northwest are included as a baseline hydro resource and are dispatched on an hourly basis in RESOLVE (Section 6.7.2). The quantity of specified hydro imported into California is based on historical import data from BPA and Powerex as reported in CARB's GHG emissions inventory.[33] Annual specified imports (in GWh/yr) are converted to an installed capacity using the annual capacity factor of NW Hydro – this is for modeling purposes and is not meant to reflect contractual obligations for capacity.

*Table 25. RESOLVE large hydro installed capacity.*

| Region | Total (MW) |
|---|---|
| BANC | 2,040 |
| CAISO | 6,662 |
| IID | - |
| LADWP | 1,005 |
| NW | 20,791 |
| NW Hydro for CAISO | 1,598 |
| SW | 2,594 |

In SERVM, no distinction is made between hydro and other imports from the Pacific Northwest. In other words, hydro imports are combined with unspecified imports. During post processing for calculating GHG emissions, SERVM will use the RESOLVE assumed amount of specified hydro import from the Pacific Northwest to debit from SERVM unspecified imports.

## 3.4 Energy Storage

### 3.4.1 Pumped Storage

Existing pumped storage resources in CAISO are based on the CAISO Master Generating Capability List and shown below.

*Table 26. Existing pumped storage resources in CAISO*

| Unit | Capacity (MW) |
|---|---|
| Eastwood | 200 |
| Helms | 1,218 |

[33] CARB GHG Current California Emission Inventory Data available at: https://ww2.arb.ca.gov/ghg-inventory-data

| | |
|---|---|
| Lake Hodges | 40 |
| O'Neil | 25 |
| **Total** | **1,483** |

The individual existing pumped storage resources shown in the table are aggregated into one resource class. The total storage capability of existing pumped storage in MWh is calculated based on input assumptions in CAISO's 2014 LTPP PLEXOS database.

### 3.4.2 Battery Storage

Baseline storage resources in the 2022-2023 IRP cycle include all battery storage that is currently installed in the CAISO footprint, as well as further battery storage in-development up till the November 2022 LSE filings. The duration of baseline utility scale storage resources will also reflect data from the November 2022 LSE filings. Baseline behind-the meter storage resources are based on data received from CEC in 2022.

*Table 27. Baseline battery storage (MW)*

| Battery Storage Resource | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| Utility-scale | 9,024 | 9,074 | 9,175 | 9,175 | 9,175 | 9,175 | 9,175 |
| Behind-the-meter | 1,343 | 1,561 | 2,010 | 2,474 | 3,698 | 4,953 | 6,208 |

## 3.5 Demand Response

Shed (or "conventional") demand response reduces demand only during peak demand events. The 2022-2023 IRP cycle treats the IOUs' existing shed demand response programs as baseline resources. Shed demand response procured through the Demand Response Auction Mechanism (DRAM) is included. The assumed peak load impact of demand response is based on final Load Impact Protocol (LIP) reports by the IOUs.[34]

*Table 28. Baseline shed demand response (MW)*

| | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|

[34] Guide to CPUC's Load Impact Protocols (LIP) Process v3.1. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/lip-filing-guide-and-related-materials/lip-filing-guide-v31.pdf

| | | | | |
|---|---|---|---|---|
| Baseline Shed Demand Response (MW) | 1,842 | 1,665 | 1,693 | 1,693 |

An additional 582 MW of interruptible pumping load from the CAISO NQC list is included as baseline shed DR capacity in all years.

## 3.6 External Zone Calibration in RESOLVE

Additional calibration of external zones is necessary to reflect planned resource developments outside of CAISO. RESOLVE does not optimize the resource mix in external zones, and there are no candidate resources in these zones that the model can select. RESOLVE does evaluate operations in these zones, using the baseline portfolio, to ensure loads and resources are balanced. The baseline defined by WECC 2032 ADS includes only online resources and specific near-term additions; it does not reflect potential future resources that may be necessary to meet loads and policy targets in external zones.

In the absence of future resource additions in the external zones, RESOLVE may overbuild within CAISO and export large amounts of energy to external zones to fill the gap. This dynamic would not realistically occur, as external LSEs would typically pursue their own plans rather than rely on CAISO to support them. To prevent these atypical CAISO exports from occurring in the model, external zones are calibrated for RESOLVE by estimating future resource additions and adding them to the baseline.

Two steps were taken to create a portfolio of future resource additions. First, planned builds from the most recent IRP of each external LSE were added to the baseline, excluding resources already within WECC 2032 ADS. Second, where IRPs did not extend through 2045, further resource additions were extrapolated using the same build rate as the IRP plans. The future resource additions input into RESOLVE are shown in Table 29. These resource additions are assumed to meet the clean energy policy objectives within each LSE's jurisdiction.

Although the model does not optimize external zone resources, RESOLVE can consider these additions when optimizing imports and exports with CAISO.

SERVM does a separate external zone calibration, which is described in Section 6.1.1.2.

*Table 29. Baseline Renewables in Other California Entities (MW)*

| Zone | Resource Class | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| **BANC** | Geothermal | 7 | 275 | 215 | 215 |
| | Li-Battery | 248 | 1,248 | 1,348 | 1,648 |
| | Solar | 523 | 2,825 | 3,625 | 4,625 |
| | Wind | 228 | 834 | 1,734 | 2,734 |
| | **BANC Total** | **1,006** | **5,182** | **6,922** | **9,222** |

| | | | | | |
|---|---|---|---|---|---|
| **IID** | Geothermal | - | 20 | 20 | 20 |
| | Solar | - | 435 | 435 | 435 |
| | **IID Total** | **-** | **455** | **455** | **455** |
| **LDWP** | Geothermal | 210 | 350 | 350 | 350 |
| | Li-Battery | 865 | 1,085 | 1,255 | 1,725 |
| | Peaker | 640 | 1,520 | 2,470 | 2,590 |
| | Solar | 1,010 | 1,410 | 1,790 | 1,950 |
| | Wind | 500 | 1,290 | 2,750 | 3,320 |
| | **LDWP Total** | **3,225** | **5,655** | **8,615** | **9,935** |
| **NW** | Li-Battery | 529 | 1,551 | 1,972 | 4,512 |
| | Nuclear | - | - | - | 650 |
| | Peaker | 1,158 | 2,288 | 4,314 | 6,888 |
| | Solar | 524 | 3,226 | 5,163 | 10,631 |
| | Wind | 785 | 5,525 | 9,690 | 16,727 |
| | **NW Total** | **2,996** | **12,591** | **21,139** | **39,408** |
| **SW** | Li-Battery | 400 | 5,489 | 12,352 | 19,766 |
| | Peaker | - | - | 1,268 | 2,656 |
| | Solar | 3,060 | 9,442 | 15,284 | 23,598 |
| | Wind | 527 | 1,501 | 2,997 | 4,074 |
| | **SW Total** | **3,987** | **16,432** | **31,902** | **50,094** |

# 4. Resource Cost Methodology

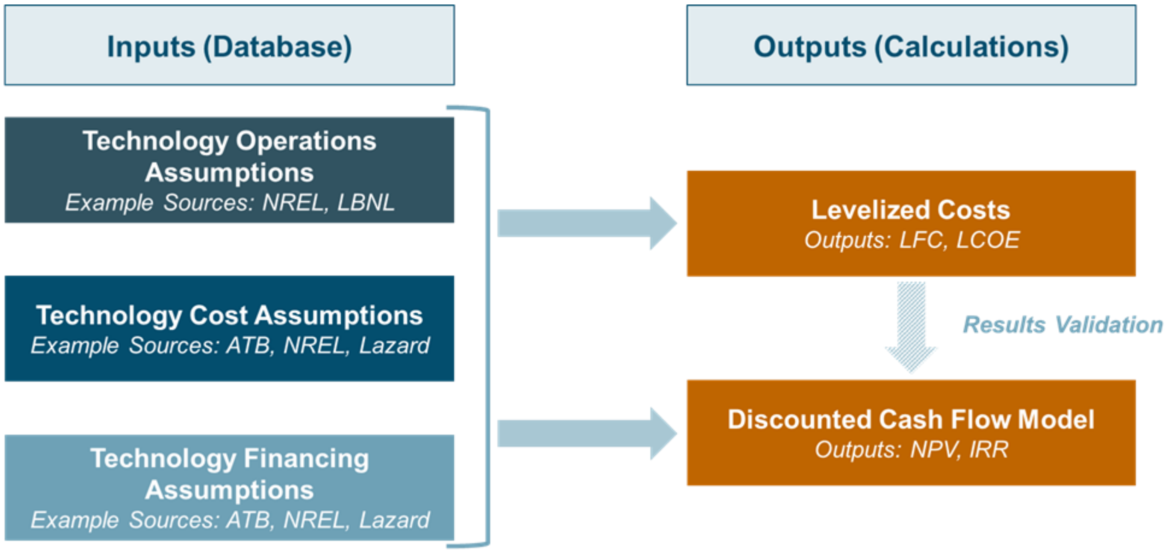
## 4.1 Pro Forma Financial Model

The pro forma model is a discounted cash flow model used to calculate the levelized costs of different candidate resources. Given a set of technology-specific assumptions for operations, cost, and financing, the pro forma computes the total (or "all-in") levelized fixed cost for each technology.[35] Ultimately, the results of the pro forma calculation are used by RESOLVE to

[35] In the RESOLVE context, "technology" is often used to refer to a generic category of resources and is location-independent, e.g., "onshore wind" or "utility-scale solar PV." "Resource" is often location-dependent, e.g., "Northern_California_Wind" or "Greater_LA_Solar", with regional or locational adjustments to resource characteristics (e.g., capacity factor) and costs (e.g., regional or state cost multipliers) incorporated in their inputs in RESOLVE.

determine which candidate resources will be the most cost-effective to build over the modeling horizon. The key inputs and outputs of the pro forma model are illustrated in Figure 1.[36]

*Figure 1. Schematic of the IRP pro forma model*




*LFC = levelized fixed cost. LCOE = levelized cost of energy. NPV = net present value. IRR = internal rate of return.*

Technology operating assumptions include non-specific capacity factor, degradation rate, and heat rate assumptions. Cost assumptions include overnight capital cost, fixed and variable O&M, interconnection, and property taxes. Financing assumptions include financing lifetime and debt period, debt fraction, costs of debt and equity, and tax credit monetization assumptions.

The components to total levelized fixed costs calculated by the pro forma include overnight capital cost, financing costs (including investor returns on a project), fixed O&M costs, and any federal tax credits, such as the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which are used to offset the high overnight capital costs of candidate renewable resources. The total levelized fixed cost is calculated using a discount rate equal to the assumed cost of equity.

[36] Levelized costs for emerging technologies are generated using the same pro forma model, with cost and performance data coming from various sources (E3 analysis, scientific and manufacturer literature), as documented in the *CPUC IRP Zero-Carbon Technology Assessment* report, published in September 2022: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/cpuc-irp-zero-carbon-technology-assessment.pdf.

Total levelized fixed costs are reported in units of $/kW of capacity and are used to determine RESOLVE's candidate resource build decisions.

The pro forma also calculates the levelized cost of energy (LCOE) for each resource. The LCOE represents the volumetric cost of electricity ($/MWh) needed for the candidate resource to recapture its total fixed and variable costs. At an internal rate of return (IRR) equal to the cost of equity, the net present value (NPV) of a candidate resource that collects revenue on electricity at the LCOE will be zero. The pro forma performs this analysis through a simplified cash flow model as a check to ensure model accuracy. The LCOE is not an input to RESOLVE but can be inferred from the model's dispatch results. The LCOE calculated by the pro forma is often used for comparing technology costs, independent of regional variations or location-specific costs. When doing so, it is important to understand that the results for LCOE are illustrative and do not represent the actual costs for specific resources. The capacity factors used to calculate LCOE in the pro forma are generic, whereas specific resources have capacity factors that vary by location or resource availability. Additionally, the LCOE in the pro forma is calculated using production estimates exclusive of curtailment. Since RESOLVE can curtail production for wind and solar resources, LCOE values reported in RESOLVE may be higher than what is reported in the pro forma. Finally, the LCOE is a metric of new technology costs, not an indicator of electricity prices. The pro forma does not estimate market electricity prices, contracted PPA electricity rates, nor does it provide forecasts of these market prices or contract rates.

The pro forma used for the 2022-2023 IRP cycle assumes that financing is provided by an Independent Power Producer (IPP), reflecting the current development practice of third-party ownership of new resources in California. Financing assumptions in the pro forma model are based on NREL's 2023 ATB[37] and will be revisited and updated as needed when new data sources become available.

Levelized costs are calculated in the pro forma on a real-levelized basis to yield costs that are flat in real dollars. This approach discounts annual project costs using a nominal discount rate (nominal return on equity) and discounts energy and capacity using a real discount rate (real return on equity). This is a standard approach that yields levelized costs in flat real terms for input to the RESOLVE model.

[37] Financing assumptions include weighted average cost of capital (WACC), cost of debt, cost of equity, and debt fraction.

The pro forma also requires information on variable costs (such as fuel and variable O&M) and resource performance characteristics (such as capacity factor). These inputs are considered in the pro forma financing optimization but have minimal impacts on levelized fixed costs. In addition, variable costs included in the pro forma model do not directly flow through to RESOLVE as inputs in the modeling process. Fuel costs, variable O&M costs, and capacity factors (modeled through renewable generation profiles) are separately specified in RESOLVE and are discussed in Section 6.

The pro forma model leverages data sources such as the NREL ATB and the Pacific Northwest National Laboratory (PNNL) Energy Storage Grand Challenge (ESGC) Cost and Performance Database, which provide location-agnostic technology cost data.[38] Regional adjustments are made to specific resources modeled in RESOLVE to reflect state-specific cost conditions. For a given technology and region (state or territory), the regional cost multiplier is calculated by applying a labor cost multiplier to the percentage of resource capital costs attributable to labor. The labor cost multipliers are computed from median wages by region for Construction Laborers, relative to the U.S. national median wage.[39] The percentages of resource capital costs attributable to labor are adopted from the 2019 WECC Cost Calculator.[40] The regional cost multipliers are applied to resource capital costs and fixed operations and maintenance (O&M) costs. These adjustments are included in the Resource Costs and Build Excel workbook, a separate Excel workbook from the pro forma, both of which are published on the CPUC website as part of the RESOLVE package. Candidate resource costs by technology are described in Section 5.

## 4.2 Overview of Resource Cost Data Sources

Several public data sources have been used to derive resource cost inputs for RESOLVE, including the NREL ATB,[41] PNNL Energy Storage Grand Challenge (ESGC) Cost and Performance Database,[42] and a site-specific report from NREL on the cost of floating offshore wind energy in California (OCS Study BOEM 2020-048).[43] These data sources have been used for current

[38] Lazard's Levelized Cost of Energy Plus (LCOE+) has been replaced by NREL ATB as the data source for Li-ion batteries; see Section 4.2 for discussion.
[39] U.S. Bureau of Labor Statistics, Occupational Employment and Wage Statistics, 47-2061: Construction Laborers. https://www.bls.gov/oes/current/oes472061.htm.
[40] WECC 2019 Generator Capital Cost Tool - with E3 Updates. July 2019. https://www.wecc.org/Administrative/E3_WECC_Cost_Calculator_2019-07-02_FINAL.xlsm.
[41] NREL 2023 Annual Technology Baseline (ATB). https://atb.nrel.gov/.
[42] PNNL Energy Storage Grand Challenge (ESGC) Cost and Performance Database: https://www.pnnl.gov/ESGC-cost-performance.
[43] Beiter, Philipp, et. al. *The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032*. NREL/TP-5000-77384. 2020. https://www.nrel.gov/docs/fy21osti/77384.pdf.

technology costs, long-term cost forecasts, financing assumptions, and other relevant assumptions, as summarized in Table 29.

*Table 29. Summary of data sources used to derive RESOLVE resource cost inputs.*

| Category | Data Source |
|---|---|
| Financing assumptions<br>(Cost of debt, cost of equity, debt fraction) | NREL ATB (default candidate resources)<br>PNNL ESGC (emerging technologies) |
| Thermal resource costs<br>(Gas CCGT, gas CT) | NREL ATB (capital costs, fixed O&M costs for candidate resources)<br>CEC 2018 Report[44] (fixed O&M costs for existing resources) |
| Solar PV resource costs | NREL ATB |
| Onshore wind resource costs | NREL ATB |
| Offshore wind resource costs | NREL ATB (overnight capital cost)*<br>NREL Floating Offshore Wind Report[29] (location-specific grid connection costs) |
| Geothermal resource costs | NREL ATB |
| Biomass resource costs | NREL ATB |
| Li-ion battery resource costs | NREL ATB* |
| Flow battery resource costs | PNNL ESGC* |
| Pumped hydro storage resource costs | NREL ATB |
| Adiabatic compressed air energy storage (A-CAES) resource costs | PNNL ESGC |

** Change from previous cycles*

Generally, NREL ATB is used as the main data source for resource costs for most technologies, with PNNL ESGC only referenced for flow batteries and A-CAES, which are not included in ATB. For flow batteries, this data source represents an update from the Lazard Levelized Cost of Storage (LCOS) v4.0 report (2018). Additionally, the financing assumptions for all emerging technologies are adapted from PNNL ESGC. The current versions of both reports are NREL 2023 ATB and PNNL ESGC Cost and Performance Assessment 2022. NREL ATB is the preferred data source for IRP because it is publicly available and has historically led to results that closely align with industry data.

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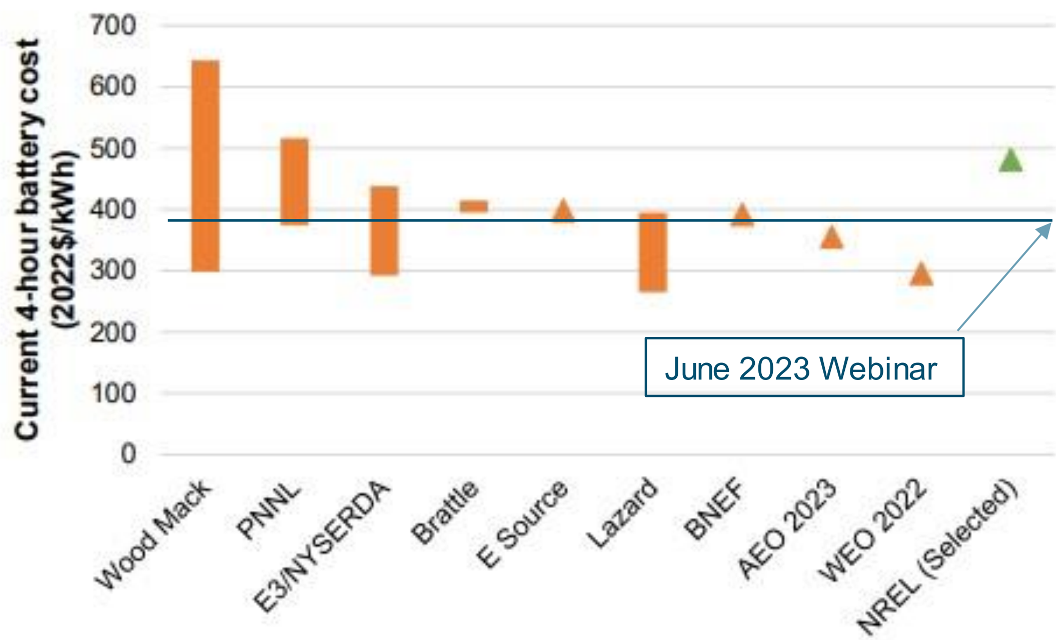
[44] Neff, Bryan. 2019. *Estimated Cost of New Utility-Scale Generation in California: 2018 Update*. California Energy Commission. Publication Number: CEC-200-2019-500. https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-005.pdf.

Additionally, the resource cost data sources for Li-ion batteries and offshore wind have been re-evaluated. For batteries, the 2023 update to NREL's "Cost Projections for Utility-Scale Battery Storage", published this summer, includes a review of 4-hour Li-ion battery capital cost assumptions from a collection of public reports (Figure 2)[45]. The value that was presented at the June 2023 Modeling Advisory Group (MAG) Webinar[46] falls roughly along the median of this data set, equal to the "High" scenario from Lazard (LCOE+)[47], but lower than the NREL 2023 ATB value. Staff used the NREL 2022 ATB to derive the value presented at the June 2023 MAG Webinar and feels confident in the continued use of the latest NREL 2023 ATB as the data source for Li-ion battery storage costs.

*Figure 2. 4-hour utility-scale Li-ion battery overnight capital cost comparison from literature, along with value reported in the June 2023 Modeling Advisory Group (MAG) Webinar. Figure adapted from (47).*




For offshore wind, the previous IRP cycle used the location-specific 2020 NREL Cost of Floating Offshore Wind in California report for its offshore wind capital cost and grid connection costs. That report was based on cost estimates that were originally developed in 2019. In addition to real increases in commodity prices that have occurred over the past four years, which should

[45] Cost Projections for Utility-Scale Battery Storage: 2023 Update, NREL. https://www.nrel.gov/docs/fy23osti/85332.pdf.

[46] CPUC IRP Inputs and Assumptions MAG Webinar https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/draft_2023_i_and_a_workshop_slides.pdf

[47] 2023 Levelized Cost of Energy+, Lazard. https://www.lazard.com/research-insights/levelized-cost-of-energyplus/

increase the initial overnight capital cost over and above the reported values, the cost decline trajectories from that data source assume immediate cost reductions from 2019-2023, which are inconsistent with the amount of progress that has been made to develop the domestic infrastructure needed to deploy these resources in California. Given these observations, an update to this data source is prudent. Staff notes the methodology developed at NREL to produce the 2020 report has since been incorporated into the NREL ATB, which is the core data source for other conventional technologies. Indeed, in the documentation for offshore wind from the NREL 2023 ATB, the report explicitly states that "Wind Resource Class 12 most closely represents [NREL's] most recent assessment of the resource characteristics of mid-term deployment for floating technology in the California Wind Energy Areas defined by the Bureau of Ocean Energy Management," referencing the 2020 report.[48] To ensure that the latest cost assumptions are being incorporated into IRP modeling efforts, NREL ATB will become the primary data source for offshore wind resource capital costs. However, to retain the site-specificity of the 2020 report, the grid connection costs from that report will continue to be used, instead of the default values from NREL 2023 ATB.

Updates to most of the data sources in Table 29 are available on an annual basis. The resource cost inputs for RESOLVE are updated as new versions of the data sources become available. Cost data for emerging technologies are discussed in Section 5.7.

## 4.3 Impacts of Inflation Reduction Act

The Inflation Reduction Act (IRA) will have an extensive impact on climate and energy investments in the U.S. In the context of IRP RESOLVE modeling, the IRA is expected to have the most direct impact on the costs of candidate clean energy resources, primarily via extending existing tax credits beyond 2024, and creating new technology-neutral tax credits, which take effect in 2025.

The IRA introduces new tax credit options for both conventional and emerging technologies to encourage new development. Effective immediately, new solar projects under the IRA can now qualify for the production tax credit (PTC) as an alternative to the investment tax credit (ITC). Early analysis (see Section 5.2.3.1, Figure 7) indicates that the PTC may be more advantageous on a present value basis for solar projects with a high-capacity factor (e.g., > 30%) and low capital cost (e.g., < $1,100/kW-ac), all else being equal. This analysis serves as the basis for RESOLVE cost inputs for candidate solar resources, which are being modeled to elect the PTC. Another major development arising from the IRA is that standalone storage will have access to

[48] https://atb.nrel.gov/electricity/2023/offshore_wind.

the ITC. Previously, storage projects could only receive the ITC if they were paired with on-site renewable generation and constrained to not charge from the grid. With this change, both conventional and emerging energy storage technologies will be eligible to receive these tax benefits without these constraints. To encourage investments in emerging technologies such as hydrogen and carbon capture and storage (CCS), new tax credits for systems that produce green electrofuels and thermal generators equipped with carbon sequestration technologies will continue to shape the competition for clean electricity to meet increasingly stringent economywide climate goals.

Key details related to implementation and the quantification of costs and benefits from the IRA are subject to pending guidance from the U.S. Treasury Department's Internal Revenue Service. The assumptions and results presented here reflect information available at this time and will continue to be refined as new information and guidance become available.

Under the IRA, projects have access to several tax credit options, with the incentive rate dependent on the number of eligibility requirements met. The different tax credit schedules for utility-scale resources are illustrated in Figure 3. Note that the horizontal axes in the charts in Figure 3 reflect project commercial operation dates, and each data point indicates the tax incentives available to eligible projects that come online in the specified year. The full credit amount (ITC at 30% of qualifying capital expenditure or PTC at $26/MWh[49] of electricity generation) is available to projects only if specific prevailing wage and apprenticeship requirements are met, shown as the "Bonus" option in Figure 3. Otherwise, the credit amount is one-fifth of the full amount ("Base"). To meet the prevailing wage requirement, laborers and mechanics employed in the construction, alteration, or repair of the facility must be paid wages not less than the prevailing wage, as determined by the U.S. Department of Labor. To meet the apprenticeship requirement, a certain number of labor hours for the work must be performed by apprentices.[50] Given the five-fold increase in incentive rate for fulfilling these requirements,

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[49] Production tax credit amounts in this section are shown in 2022 dollars.

[50] More details on the IRA tax credits, including the prevailing wage and apprenticeship requirements, and the different tax credit adders, can be found here:

(a) Orrick. IRA Update: What to Know About the New Guidance on Prevailing Wage and Apprenticeship Requirements. December 2022. https://www.orrick.com/en/Insights/2022/12/Initial-Guidance-On-Prevailing-Wage-And-Apprenticeship-Requirements

(b) Norton Rose Fulbright. IRS Issues Wage and Apprentice Requirements. November 2022. https://www.projectfinance.law/publications/2022/november/irs-issues-wage-and-apprentice-requirements/

(c) Internal Revenue Service (IRS). Prevailing Wage and Apprenticeship Initial Guidance Under Section 45(b)(6)(B)(ii) and Other Substantially Similar Provisions. November 2022.

it is reasonable to assume that most project developers will strive to meet the prevailing wage and apprenticeship requirements to remain cost-competitive. These requirements are also believed to be actionable for most projects, based on an initial review of current and expected labor cost increases implied by the prevailing wage requirement, although further analysis of net impact on costs is required following initial guidance from the Treasury Department on these requirements. For these reasons, the full IRA credit amount, or the "Bonus" option in Figure 3, is assumed to be the base case IRA scenario for calculating the resource cost inputs in the 2022-2023 IRP cycle.

Tax credits under the IRA are scheduled to expire at the later of (a) 2032, and (b) when the U.S. electric sector achieves 75% GHG emissions reductions relative to 2022 levels, at the national level.[51] Once this condition is met, the credits undergo a three-year phase-out before being retired. Staff expects that the 75% emissions target will not be met until 2045, which is reflected in the timing for the IRA tax credit schedules in Figure 3.

In addition to the 30% ITC and $26/MWh "Bonus" credit rates offered under the IRA, certain credit adders are available and may be stacked for projects that meet additional requirements. Beginning in 2025, an extra 10% of ITC or $2.60/MWh of PTC can be claimed by projects that meet the domestic content requirement. The project must source a certain portion of any steel, iron, or other manufactured product used to construct the facility in the U.S. to qualify. Another 10% adder can be claimed if the project is in an energy community, which includes regions where employment has historically depended on fossil fuel generation, and fossil fuel brownfield sites. The "Bonus+10" and "Bonus+20" options in Figure 3 illustrate the cases in which an additional 10% and 20% credit are available, respectively, relative to the "Bonus" option. Among these IRA adders, location-specific incentives (e.g., energy community) are feasible and may be worth considering as a sensitivity, given that potential qualification is quite broad in California.[52] The domestic content requirement incentives could also have a significant

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https://www.federalregister.gov/documents/2022/11/30/2022-26108/prevailing-wage-and-apprenticeship-initial-guidance-under-section-45b6bii-and-other-substantially

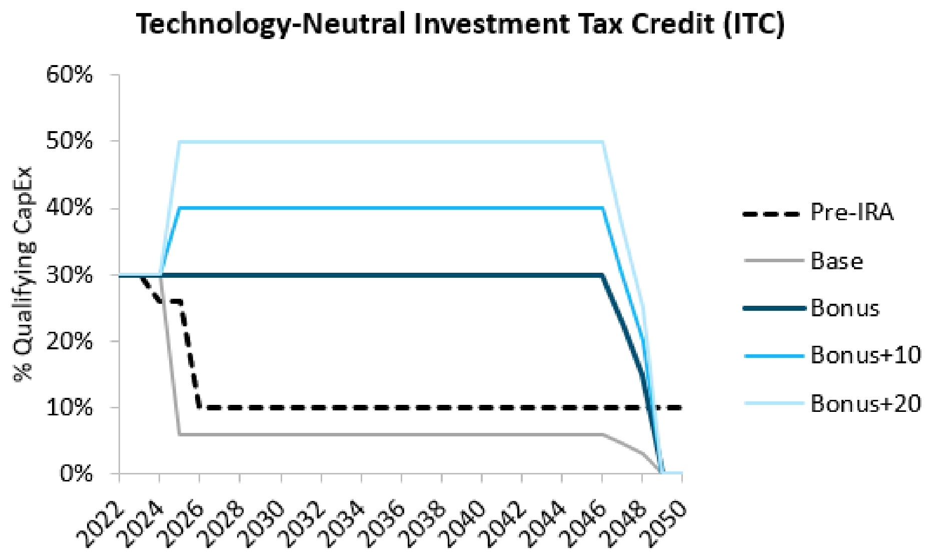
(d) McGuireWoods. Inflation Reduction Act Extends and Modifies Tax Credits for Wind Projects. August 2022. https://www.mcguirewoods.com/client-resources/Alerts/2022/8/inflation-reduction-act-tax-credits-for-wind-projects.

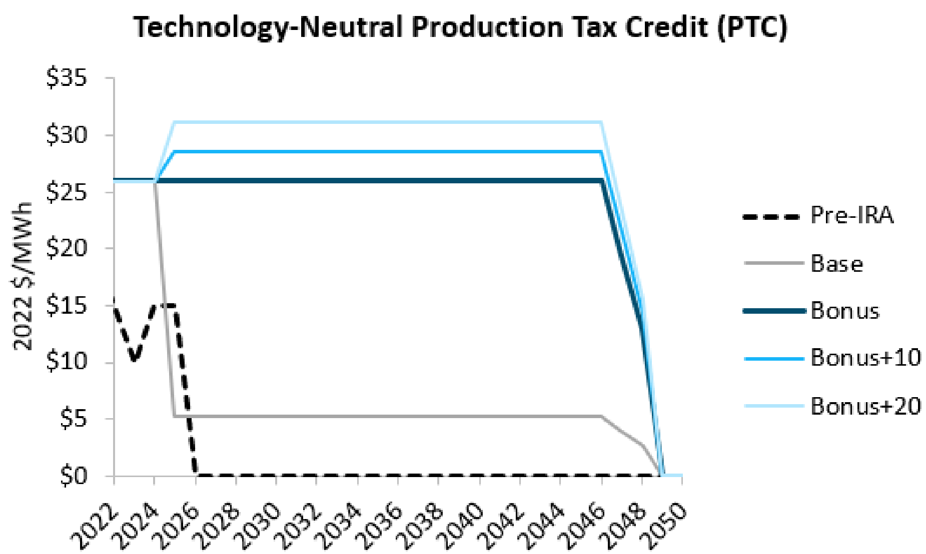
[51] Inflation Reduction Act Summary: Energy and Climate Provisions. https://www.energy.gov/sites/default/files/2022-10/IRA-Energy-Summary_web.pdf.

[52] See, for example: S&P Capital IQ. Mapping communities eligible for additional Inflation Reduction Act incentives. October 2022. https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?KeyProductLinkType=2&id=72375231.

impact on project economics, although it is more likely to be influenced by uncertainties in the supply chain and will not be considered at this time.

*Figure 3. Assumed IRA tax credit availability for technologies by project commercial operation date.*




The IRA impacts on individual resource costs are shown in Section 5.2.3 (biomass, geothermal, utility-scale solar, onshore wind, offshore wind), Section 5.3 (pumped storage, battery storage, and compressed air energy storage), and Section 5.7 (emerging technologies).

## 4.4 Impacts of Commodity Prices on Resource Costs

At the September 2022 Inputs and Assumptions Modeling Advisory Group Webinar, Parties raised concerns about recent increases in commodity prices and their potential impacts on resource costs. While inflationary pressures and supply chain issues have affected all technologies in recent months, the primary issue identified was that certain technologies may be disproportionately impacted by these market pressures. Specifically, price increases for certain metals and other raw materials may drive up the costs for some technologies, and consequently impact new capacity expansion decisions in RESOLVE.

Several reports have been published in recent months which support this position. Studies from Bloomberg New Energy Finance (BNEF)[53] and Wood Mackenzie[54] both suggest that renewable technologies—wind, solar, and lithium-ion (Li-ion) batteries, specifically—have seen upticks in Levelized Cost of Electricity (LCOE) and overnight system capex since mid-2020. Supply chain issues and inflation in the aftermath of the COVID slowdown have impacted these technologies more significantly than others in recent years.

In addition, there is clear evidence that one of the contributing factors to these cost increases is a disproportionate increase in commodity prices. Data reported by the International Monetary Fund (IMF) on feedstock material prices show that since Q1 2019, many rare-earth metals critical to the production of Li-ion batteries, including lithium, manganese, nickel, and cobalt, have more than doubled in price, outpacing inflation. These price increases are roughly 50% greater than those observed for conventional feedstocks, such as aluminum, iron, and copper.[55]

While current market pressures have resulted in recent increases in resource costs for wind, solar, and Li-ion batteries, it is not unreasonable to expect that these resources will continue to experience real cost decline over time, as projected in NREL ATB and assumed in most cost forecasting models. However, the passing of the Inflation Reduction Act (IRA) may affect those schedules. As discussed in Section 4.3, the IRA represents a landmark investment in renewable energy in the U.S., with a stated objective of accelerating decarbonization nationwide. It stands to reason that, because of this legislation, the markets for renewable technologies will

[53] "Cost of New Renewables Temporarily Rises as Inflation Starts to Bite." Bloomberg New Energy Finance, 2022. https://about.bnef.com/blog/cost-of-new-renewables-temporarily-rises-as-inflation-starts-to-bite/

[54] U.S. Solar Market Insight, Executive Summary, Q3 2022. Wood Mackenzie. https://www.woodmac.com/industry/power-and-renewables/us-solar-market-insight/

[55] IMF Quarterly Data retrieved Q4 2022. https://data.imf.org/?sk=471DDDF8-D8A7-499A-81BA-5B332C01F8B9&sId=1390030341854

experience a sustained increase in real demand. This increased demand may further impact supply chains which have already been struggling to re-adjust since the beginning of the COVID slowdown. The stance that real demand will accelerate in the intermediate- to long-term is supported by reports from McKinsey[56] and the International Energy Agency (IEA)[57] that project dramatically increased demand in rare earth metals in the 2020-2040 horizon.

Due to observed increases in commodity prices that have disproportionately affected wind, solar, and Li-ion batteries, and an expected increase in demand for these technologies, which are promoted by the IRA, Staff has decided to modify the resource cost assumptions for utility-scale PV, onshore wind, offshore wind, and Li-ion batteries to delay the cost declines trajectories as reported in NREL ATB, although the IRA incentive benefits are reflected in the cost trajectories. These modifications for utility-scale PV, onshore wind, offshore wind, and Li-ion batteries are explained in Sections 5.2.3.1, 5.2.3.2, 5.2.3.3, and 5.3.2, respectively.

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[56] "The raw-materials challenge: How the metals and mining sector will be at the core of enabling the energy transition." McKinsey, 2022. https://www.mckinsey.com/industries/metals-and-mining/our-insights/the-raw-materials-challenge-how-the-metals-and-mining-sector-will-be-at-the-core-of-enabling-the-energy-transition

[57] "The Role of Critical Minerals in Clean Energy Transitions: Mineral requirements for clean energy transitions." IEA, 2021. https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions/mineral-requirements-for-clean-energy-transitions

## 5. Optimized Resources

Optimized resources represent the menu of new resource options from which RESOLVE can select to create an optimal portfolio. Optimized resources are in two categories:

- Candidate resources included in all cases (default candidate resources): established, commercially viable resource technologies such as solar, wind, geothermal, Li-ion batteries, pumped hydro storage, shed demand response, and candidate thermal resources.
    - 2022 LSE planned additions are modeled as minimum build limit for some of these candidate resources.
- Additional candidate resources included in sensitivities (non-default candidate resources): more experimental and/or are not yet commercially mature such as shift demand response, emerging technologies, vehicle-to-grid integration.

This document defines guiding principles for a resource to become a default candidate resource in IRP modeling. During each IRP portfolio development, staff evaluates the non-default candidate resources based on these guiding principles and determines if a resource meets the criteria to be a default candidate resource. A default candidate resource must be:

- **Viable:** This resource is a commercialized technology.
- **Scalable:** This resource could be realistically selected at sufficient volume to meaningfully impact California's electric portfolio.
- **Economic:** This resource is projected to be cost competitive within the timeframe of IRP analysis with sufficient publicly available market data to validate those projections.
- **Actionable:** Mechanisms exist, or could be reasonably expected to be put in place, to enable the CPUC to guide procurement of this resource.
- **Timely:** This resource can reasonably be expected to come online within the timeframe of IRP analysis.

The optimal mix of candidate resources is a function of the relative costs and characteristics of the entire resource portfolio (both baseline and candidate) and the constraints that the portfolio must meet. Capital costs are included in the RESOLVE optimization for candidate resources, whereas capital costs are excluded for baseline resources. Generation profiles and operating characteristics are addressed in Section 6.

Other non-optimized resource additions that have prescribed adoption over time from IEPR forecasts, are not represented in RESOLVE as decision variables in the optimization model including energy efficiency, BTM solar and storage.

## 5.1 Natural Gas

The 2022-2023 IRP cycle includes three technology options for new natural gas generation: Advanced Combined Cycle Gas Turbine (CCGT), Aeroderivative Combustion Turbine (CT), and Reciprocating Engine. Each option has different costs, efficiency, and operational characteristics. Natural gas generator all-in fixed costs are derived from NREL's 2023 Annual Technology Baseline[58] and resource costs developed for WECC by E3.[59] Natural gas fuel costs are discussed in Section 6.8. Operational assumptions for these plants are summarized in Section 6.3. The first year that new natural gas generation is assumed to be able to come online is 2025, in the case of upgrades or incremental resources, first online years for the additional capacity will be treated on a case-by-case basis.

*Table 30. Capital, fixed O&M, and all-in fixed costs for candidate natural gas resources (2022 $)*

| Resource Class | Capital Cost ($/kW) | Fixed O&M Cost ($/kW-yr) | All-In Fixed Cost ($/kW-yr) |
|---|---|---|---|
| CAISO_Advanced_CCGT | $1,174 | $31.7 | $140 |
| CAISO_Aero_CT | $1,413 | $23.8 | $152 |
| CAISO_Reciprocating_Engine | $1,413 | $23.8 | $152 |

## 5.2 Renewables

RESOLVE can select from the following candidate renewable resources:

- Biomass
- Geothermal
- Solar Photovoltaic (PV)
- Onshore Wind
- Offshore Wind

Candidate solar PV resources are represented as either utility-scale or distributed. Utility-scale and distributed solar resources differ in cost (Section 5.2.3.1), transmission (Section 5.5), and performance (Section 6.2) assumptions.

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[58] NREL 2022 Electricity Annual Technology Baseline. https://atb.nrel.gov/electricity/2023/index

[59] Generation and Transmission Resource Cost Update 2019. June 2019. https://www.wecc.org/Administrative/E3-WECC%202019%20Resource%20Cost%20Update%20Summary-20190628.pptx. Capital costs for aeroderivative combustion turbine and reciprocating engine are derived from this data source, with the latter assumed to be the same as the former.

Two types of distribution-level solar resources are modeled in RESOLVE in the IRP context:

- **Customer solar ("Customer_PV")** represents behind-the-meter (BTM) rooftop solar and is a mix of mostly residential and some commercial solar resources that benefit from net energy metering (NEM). "Customer_PV" is not modeled as a candidate resource, meaning that its capacity is not optimized by RESOLVE. Rather, the dispatch is modeled like a supply-side resource with a specified generation profile. The installed capacity and energy and peak contribution of "Customer_PV" in RESOLVE are consistent with IEPR forecasts.
- **Distributed solar ("Distributed_Solar")** represents commercial rooftop solar and is not technically behind-the-meter. "Distributed_Solar" is available for selection in RESOLVE as a candidate resource that can be optimized.

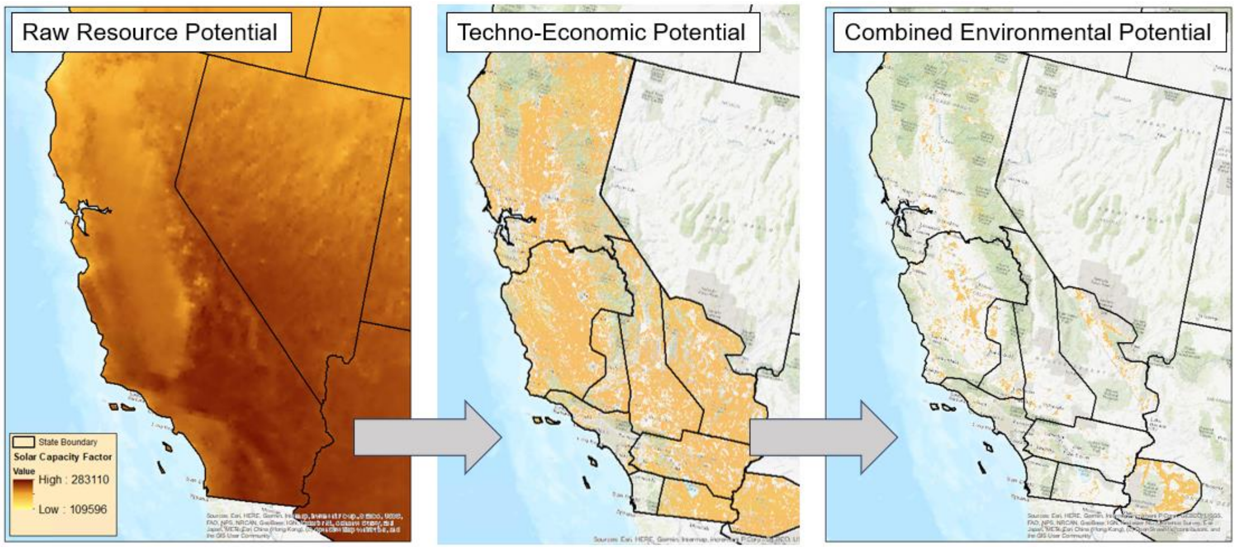
IRP aims to model utility procurement needs and transmission needs given forecasts of load, energy efficiency, customer solar adoption, etc. Although IRP allows the optimization of conventional DR and energy efficiency, it does not attempt to determine the optimal mix of customer- vs. bulk grid-sited resources for solar and wind resources. In addition, RESOLVE does not capture any transmission and distribution (T&D) benefits of customer-sited resources.

Distributed wind is not included as an optimized resource in the 2022-23 IRP model due to limited potential and higher costs, relative to utility-scale wind projects.

### 5.2.1 Resource Potentials and Land Use Screens

To characterize the resource potential available for capacity expansion modeling, geospatial analysis is performed on available land in California and throughout the Western Interconnection to identify potential sites for renewable development. The study includes an assessment of potentially viable project sites, and resource potentials within those sites, to determine an overall potential for each renewable resource in RESOLVE. In the analysis, raw resource potentials are filtered through a set of techno-economic and environmental screens to produce the potential totals. The techno-economic and environmental screens are developed using spatial analysis methods consistent with prior studies.[60--61][62][63][64][65][66] Locations which are not suitable for commercial-scale renewable energy development are screened out to produce a set of land use scenarios. There are several types of site suitability criteria which make up the screens: techno-economic criteria, legal prohibitions on development, administratively protected areas, and areas of conservation importance.

*Figure 4. Site suitability methods used to identify wind and solar technical resource potential.*




The detailed geospatial dataset is aggregated by region to produce resource potentials for each candidate resource in RESOLVE. The regional maps for solar and wind are provided in Figure 5 below. Candidate geothermal resources use the same region designations as candidate wind

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[60] Lopez, A. et. al. "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis," 2012. https://www.nrel.gov/docs/fy12osti/51946.pdf

[61] https://greeningthegrid.org/Renewable-Energy-Zones-Toolkit/topics/social-environmental-and-other-impacts#ReadingListAndCaseStudies

[62] Multi-Criteria Analysis for Renewable Energy (MapRE), University of California Santa Barbara. https://mapre.es.ucsb.edu/

[63] Larson, E. et. al. "Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Interim Report." Princeton University, 2020. https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

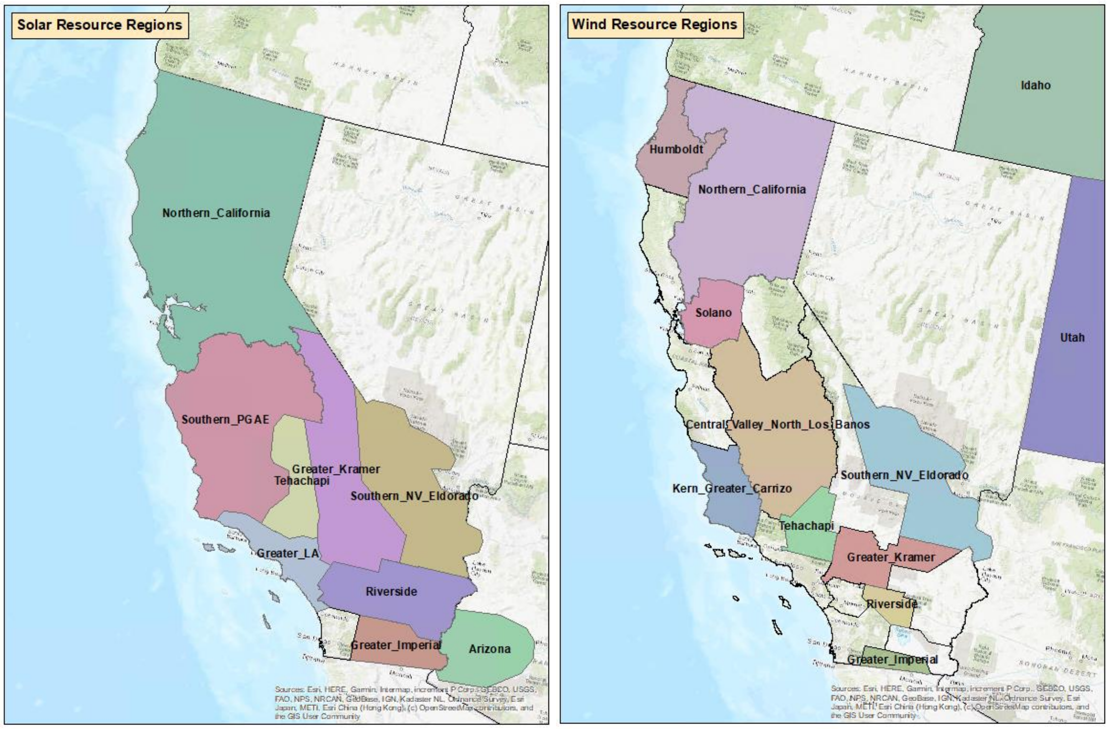
[64] Wu, G. et. al. "Low-Impact Land Use Pathways to Deep Decarbonization of Electricity." *Environmental Research Letters* 15, no. 7 (July 10, 2020). https://doi.org/10.1088/1748-9326/ab87d1.

[65] RETI Coordinating Committee, RETI Stakeholder Steering Committee. "Renewable Energy Transmission Initiative Phase 1B Final Report." California Energy Commission, January 2009.

[66] Pletka, Ryan, and Joshua Finn. "Western Renewable Energy Zones, Phase 1: QRA Identification Technical Report." Black & Veatch and National Renewable Energy Laboratory, 2009. https://www.nrel.gov/docs/fy10osti/46877.pdf.

resources. Candidate biomass and pumped hydro resources, while not modeled in GIS, also use the wind region designations.

*Figure 5. Solar (left) and Wind (right) Regional Boundaries in RESOLVE**




** Not shown: New Mexico and Wyoming Wind*

### 5.2.1.1 Raw Resource Potential Rasters

The raw resource potential GIS rasters[67] for wind and solar were created from the NREL Wind Supply Curves[68] and NREL SAM,[69] respectively. Technology-specific modeling assumptions are made regarding the design and operating characteristics of each technology. These modeling assumptions are described below.

*Table 31. Technology configuration modeling assumptions*

| | Wind | Solar | Geothermal |
|---|---|---|---|
| Typical nameplate capacity (MW) | 4 (Turbine) | 50 | N/A |
| Mounting structure | N/A | Single-axis tracking | N/A |
| Hub height / Rotor diameter | 110 m / 150 m | N/A | N/A |
| Operating losses | 16.7% | 14% | N/A |
| Azimuth | N/A | 180º | N/A |

[67] A raster consists of a matrix of cells or pixels organized into a grid where each cell contains a value representing information.
[68] NREL Geospatial Data Science, Wind Supply Curves. https://www.nrel.gov/gis/wind-supply-curves.html
[69] NREL System Advisor Model (SAM). https://sam.nrel.gov/

| | | | |
|---|---|---|---|
| Ground coverage ratio | N/A | 30% | N/A |
| Inverter loading ratio | N/A | 1.34 | N/A |
| Maximum field depth | N/A | N/A | 10 km |
| Enhanced geothermal (EGS) | N/A | N/A | Not included* |

* *While EGS is not considered here, the adoption of the 5P confidence interval expands the resource potential beyond what is typically considered economically viable in traditional methods.*

The capacity factor estimates used in the GIS resource potential and land use screens analysis are used only for estimating available land area and resource potentials; these are not the values that are used in IRP modeling. The renewable energy profiles used in IRP modeling are discussed in Section 6.2.

Geothermal potential was estimated using a combination of heat-in-place analysis and geological analogy. California geothermal resource potential was characterized using the mean resource potential values based on a 2008 report published by the U.S. Geological Survey (USGS)[70]. Out-of-state resource potential was based on a 2010 assessment performed for the Renewable Energy Transmission Initiative (RETI).[71] The resource potential characterization approach entails estimating the area, thickness, and average temperature of the exploitable reservoir in a geothermal area. The potential in megawatts (MW) is then calculated assuming a certain project life and recovery efficiency. Estimation of the amount of electricity that could be generated at various geothermal sites was based on empirically derived formulae relating the estimated amount of heat that can be converted from a site to electrical output.

#### *5.2.1.2 Techno-Economic Land Use Screens*

The site-suitability criteria included in the techno-economic land use screens are listed in the table below. As an update to previous cycles, flood zones are not included in the list of techno-economic criteria for the 2022-23 IRP. Geothermal resource potential was characterized based on published results from a 2010 study that addresses subsurface geologic criteria.[72] Equivalent techno-economic criteria such as slope, population density, and existing infrastructure were already factored into those results and are therefore not duplicated here.

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[70] Wiliams, C. et. al. "A Review of Methods Applied by the U.S. Geological Survey in the Assessment of Identified Geothermal Resources." USGS, 2008. https://pubs.usgs.gov/of/2008/1296/pdf/of2008-1296.pdf.

[71] Lovekin, J. et. al. "Geothermal Assessment as Part of California's Renewable Energy Transmission Initiative (RETI)." Proceedings World Geothermal Congress 2010. https://www.geothermal-energy.org/pdf/IGAstandard/WGC/2010/0318.pdf.

[72] Lovekin, J. et. al. "Geothermal Assessment as Part of California's Renewable Energy Transmission Initiative (RETI)." Proceedings World Geothermal Congress 2010. https://www.geothermal-energy.org/pdf/IGAstandard/WGC/2010/0318.pdf.

*Table 32. Techno-economic site suitability criteria and exclusion thresholds*

| | Solar | Wind | Geothermal |
|---|---|---|---|
| Steeply sloped areas | >10º | >10º | N/A |
| Population density | >100/km$^2$ | >100/km$^2$ | N/A |
| Capacity factor | <16% (DC) / 21.4% (AC) | <28% (CA, NV), 35% (ID, UT), 40% (WY, NM) | N/A |
| Interconnection Distance | >30 miles | >30 miles (CA, NV only) | N/A |
| Urban areas | <500 m | <1000 m | N/A |
| Water bodies | <250 m | <250 m | N/A |
| Railways | <30 m | <250 m | N/A |
| Major highways | <125 m | <125 m | N/A |
| Airports | <1000 m | <5000 m | N/A |
| Active mines | <1000 m | <1000 m | N/A |
| Military Lands | <1000 m | <3000 m | N/A |
| Existing Project Footprints | Included in screen | Included in screen | N/A |

The capacity factor exclusion thresholds for wind are 28% for in-state resources, including CAISO-interconnecting wind in Southern Nevada; 35% for Idaho and Utah; and 40% for Wyoming and New Mexico. These capacity factor thresholds are used only to inform the GIS resource potential and land use screens analysis; these values are not used in IRP modeling. The renewable energy profiles used in IRP modeling are discussed in Section 6.2.

#### *5.2.1.3 Environmental Land Use Screens*

The environmental land use screen used for in-state resources in the 2022-23 IRP cycle is the Core Land Use Screen developed in 2023 by the CEC for use in IRP modeling.[73] This layer consists of the following environmental criteria:

- Techno-economic land use screen (see above)
- Protected Area layer
- Cropland Index Model (Threshold: Mean, 7.7)
- Terrestrial Intactness Model (Threshold: Mean, 0.3)
- Biological Planning Priorities:
    - ACE Biodiversity (Rank 5)
    - ACE Connectivity (Ranks 4 & 5)
    - ACE Irreplaceability (Ranks 4 & 5)
    - Wetlands (from CA Nature Habitat and Land Cover)
    - USFWS Critical Habitat

[73] https://www.energy.ca.gov/data-reports/california-energy-planning-library/land-use-screens.

The data layers that comprise the Core Land Use Screen have been made publicly available via an online web application hosted by the CEC.[74]

For out-of-state solar resources (CAISO-interconnecting regions in Nevada and Arizona) and out-of-state wind resources (Wyoming, New Mexico, Utah, and Idaho), the environmental land use screen was created using the Risk Category 2, 3, and 4 data layers from the WECC Environmental Data Viewer, which continues to be the most comprehensive environmental land use review of the entire western U.S.[75]

#### *5.2.1.4 Resource Potential Totals*

After application of the techno-economic and environmental land use screens, the remaining areas indicate locations that meet the site suitability criteria for commercial-scale renewable energy development. These areas are then discretized into a grid of 4-km square cells. Each cell in the grid is defined to be a Candidate Project Area (CPA). For each CPA, the following location-specific attributes are calculated: area ($km^2$), nameplate capacity (MW), distance to nearest substation (km), mean elevation (m), and mean slope. Land use factors of 30 MW/$km^2$ for candidate solar[76] and 6.2 MW/$km^2$ for candidate wind[77] are assumed. This land use density factor for onshore wind was selected to align with the CEC density factor.

After the CPAs have been characterized, they are grouped to produce the available resource potential for each candidate resource in RESOLVE. For consistency with prior studies and industry standard modeling conventions, a land use discount factor of 80% is applied to the techno-economic solar resource potential to reflect socioeconomic, cultural, or other considerations that will further reduce developable land to one-fifth of the value estimated through analysis.[78] Specifically, the available solar resource potential after application of the environmental land use screens is capped at 20% of the estimated potential under the techno-economic screen.

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[74] https://www.energy.ca.gov/data-reports/california-energy-planning-library/land-use-screens/cec-2023-land-use-screens-electric.

[75] https://www.wecc.org/SystemAdequacyPlanning/Pages/Environmental-and-Cultural-Considerations.aspx.

[76] Ong, S. et. al." Land-Use Requirements for Solar Power Plants in the United States." NREL, 2013. https://www.nrel.gov/docs/fy13osti/56290.pdf.

[77] Equivalent to 40 acres/MW; Hossainzadeh, S. et. al. "Land-Use Screens for Electric System Planning: Using Geographic Information Systems to Model Opportunities and Constraints for Renewable Resource Technical Potential in California." CEC, 2023. https://www.energy.ca.gov/publications/2022/land-use-screens-electric-system-planning-using-geographic-information-systems.

78 Wu, G. et. al. "Low-Impact Land Use Pathways to Deep Decarbonization of Electricity." *Environmental Research Letters* 15, no. 7 (July 10, 2020). https://doi.org/10.1088/1748-9326/ab87d1.

The resource potentials under the techno-economic and environmental land use screens are summarized in the tables below. The techno-economic resource potential totals reflect 100% of the solar resource potential under the techno-economic land use screen (exclusive of the 80% land use discount factor). The environmental resource potential totals for solar are inclusive of the 80% discount factor, as described above. The available resource potential under the environmental land use screen represents the default assumption for RESOLVE.

*Table 33. Available in-state (CAISO-interconnecting) resource potential under the techno-economic and environmental land use screens, GW*

| Resource | | Techno-Economic | Environmental |
|---|---|---|---|
| Solar | Arizona_Solar | 443.18 | 74.69 |
| | Distributed_Solar (1) | 36.60 | 36.60 |
| | Greater_Imperial_Solar | 264.43 | 14.28 |
| | Greater_Kramer_Solar | 449.75 | 19.44 |
| | Greater_LA_Solar | 91.38 | 11.36 |
| | Northern_California_Solar | 1,279.98 | 115.19 |
| | Riverside_Solar | 191.42 | 8.69 |
| | Southern_NV_Eldorado_Solar | 511.06 | 60.60 |
| | Southern_PGAE_Solar | 1,146.26 | 119.59 |
| | Tehachapi_Solar | 240.31 | 29.06 |
| | **Total** | **4,654.39** | **489.50** |
| Wind | Baja_California_Wind (2) | 2.47 | 2.47 |
| | Central_Valley_North_Los_Banos_Wind | 7.69 | 2.81 |
| | Greater_Imperial_Wind | 2.14 | 0.13 |
| | Greater_Kramer_Wind | - | - |
| | Humboldt_Wind | - | - |
| | Kern_Greater_Carrizo_Wind | - | - |
| | Northern_California_Wind | 28.06 | 2.33 |
| | Riverside_Wind | - | - |
| | Solano_Wind | 7.22 | 0.50 |
| | Southern_NV_Eldorado_Wind | 55.27 | 5.01 |
| | Tehachapi_Wind | 14.20 | 1.73 |
| | **Total** | **117.06** | **14.99** |
| Geothermal | Greater_Imperial_Geothermal | 2.51 | 2.46 |
| | Inyokern_North_Kramer_Geothermal | 0.17 | 0.05 |
| | Northern_California_Geothermal | 0.85 | 0.85 |
| | **Total** | **3.53** | **3.36** |
| Biomass | **InState_Biomass (3)** | **1.16** | **1.16** |

*(1) Distributed_Solar resource potential is determined from prior CPUC analysis and has not been updated for the 2022-23 IRP cycle.*

*(2) Resource potential for Baja_California_Wind is equal to the sum of the Net MW to Grid for all projects in the CAISO Interconnection Queue sited in Baja California.[79]*

*(3) Biomass resource potential is determined from an earlier county-level analysis performed by CPUC and has not been updated for the 2022-23 IRP cycle.*

*Table 34. Available out-of-state resource potential under the techno-economic and environmental land use screens, GW**

| | Resource | Techno-Economic | Environmental |
|---|---|---|---|
| Wind | Idaho_Wind | 31.39 | 7.68 |
| | New_Mexico_Wind | 242.84 | 166.88 |
| | Utah_Wind | 52.26 | 18.85 |
| | Wyoming_Wind | 405.55 | 67.14 |
| | **Total** | **732.03** | **260.56** |
| Geothermal | Central_Nevada_Geothermal | 0.60 | 0.60 |
| | Northern_Nevada_Geothermal | 0.86 | 0.86 |
| | Pacific_Northwest_Geothermal | 0.52 | 0.52 |
| | Utah_Geothermal | 0.18 | 0.18 |
| | **Total** | **2.16** | **2.16** |

* *Out-of-state resources are subject to additional availability constraints pursuant to transmission deliverability to the CAISO system border. These availability constraints are discussed more in Section 5.5.4.*

Wind resource regions with no available resource potential under the environmental land use screen are not modeled in RESOLVE. The available resource potentials for candidate renewable resources are subject to additional availability constraints, which are explained in Section 5.2.2.

### 5.2.1.5 Offshore Wind Resource Potential

The offshore wind resource potential was calculated using the site areas and "High" 5 MW/km$^2$ area density factor from the June 2022 AB 525 NREL presentation.[80] The resource potential for the Diablo Canyon Dormant Call Area is set to zero due to the status of that study area, and this resource has been removed from RESOLVE modeling. The resulting offshore wind resource potential is summarized in the table below.

*Table 35. Offshore wind resource potential*

| Site | Area (sq. km) | Area Density Factor (MW/km$^2$) | Resource Potential (MW) |
|---|---|---|---|
| Diablo Canyon Dormant Call Area | 1,441 | 0 | - |
| Morro Bay WEA (Wind Energy Area) | 975 | 5 | 4,875 |
| Humboldt WEA | 536 | 5 | 2,680 |
| Cape Mendocino Study Area | 2,072 | 5 | 10,360 |

[79] Generator Interconnection Queue Report available through the CAISO Resource Interconnection Management System: https://rimspub.caiso.com/rimsui/logon.do. Accessed 4/7/23.

[80] CEC Docket 17-MISC-01. https://efiling.energy.ca.gov/GetDocument.aspx?tn=243707&DocumentContentId=77539

| | | | |
|---|---|---|---|
| Del Norte Study Area | 2,202 | 5 | 11,010 |
| **Total** | **7,226** | | **28,925** |

### 5.2.2 First Available Year and Annual Build Limits

The first available years for candidate renewable resources in the 2022-2023 IRP cycle have been updated to reflect feasible timelines for bringing resources online based on the CAISO interconnection queue and typical development lead times. The first available year in RESOLVE is applied on a resource-by-resource basis; accordingly, a range of years applies when summarizing by technology in Table 36.

*Table 36. First available year by candidate renewable resource technology*

| Resource Type | First Available Year |
|---|---|
| Solar PV | 2024 |
| Onshore Wind (in-state) | 2024-2035 |
| Onshore Wind (out-of-state) | 2026-2035 |
| Offshore Wind | 2032-2039 |
| Geothermal | 2026-2030 |
| Biomass | 2028 |

In addition to the first available years and annual deployment limits discussed in this section, candidate renewable resources are subject to CAISO transmission constraints, which may further restrict what can be selected in RESOLVE. Transmission representation is discussed in Section 5.5.

#### *5.2.2.1 Solar PV Annual Build Limits*

With large representation in the CAISO interconnection queue and strong commercial interest, solar PV is immediately available for selection in RESOLVE. However, based on LSE in-development and planned resource amounts from the 11/1/2022 filings, CAISO Interconnection Queue projected commercial operation dates, and historical annual project completion rates, an annual build limit is imposed on candidate solar resources in RESOLVE to ensure that the selected resource additions are feasible. These limits amount to 3 GW of annual capacity additions per year through 2026. After 2026, no restrictions are placed on the selection of additional solar resources.

*Table 37. Solar PV annual build limits through 2026, MW*

| Technology | 2024 | 2025 | 2026 | Total |
|---|---|---|---|---|
| Solar PV | 3,000 | 3,000 | 3,000 | 9,000 |

### *5.2.2.2 In-State Wind and Geothermal Availability*

The available resource potentials described in Section 5.2.1.4, Table 33 for CAISO-interconnecting wind and geothermal are subject to availability constraints through 2035. The schedules reported in the table below are the result of CPUC analysis of the CAISO interconnection queue, commercial interest, and anticipated construction lead times.

*Table 38. In-state (CAISO-interconnecting) wind and geothermal annual build limits, MW*

| | Resource | 2024 | 2025 | 2026 | 2028 | 2030 | 2035 |
|---|---|---|---|---|---|---|---|
| Wind | Baja_California_Wind | 0 | 0 | 350 | 350 | 600 | 2,471 |
| | Central_Valley_North_Los_Banos_Wind | 0 | 4 | 4 | 64 | Full potential | |
| | Greater_Imperial_Wind | 0 | 0 | 0 | 100 | Full potential | |
| | Northern_California_Wind | 0 | 0 | 0 | 200 | Full potential | |
| | Solano_Wind | 290 | 375 | 560 | 791 | Full potential | |
| | Southern_NV_Eldorado_Wind | 0 | 0 | 310 | 310 | Full potential | |
| | Tehachapi_Wind | 24 | 24 | 144 | 244 | Full potential | |
| Geothermal | Greater_Imperial_Geothermal | 0 | 0 | 499 | 1,045 | Full potential | |
| | Inyokern_North_Kramer_Geothermal | 0 | 0 | 32 | 50 | Full potential | |
| | Northern_California_Geothermal | 0 | 0 | 278 | 314 | Full potential | |

### *5.2.2.3 Out-of-State Wind and Geothermal Availability*

The available resource potentials described in Section 5.2.1.4, Table 34 for out-of-state wind and geothermal resources will require investments in new transmission to deliver energy and capacity to the CAISO system. Despite additional transmission costs (Section 5.5.4), the chief advantage of out-of-state resources is that these resources typically enjoy higher capacity factors than what can be sourced and interconnected directly to the existing transmission system.

Resource availability by year for out-of-state resources reflect CPUC estimates of the transmission project pipeline across the WECC. Transmission project data was submitted confidentially to Staff by stakeholders, and the analysis accounts for project lead time, likelihood of completion, and availability of line capacities for use by CAISO. The availabilities for out-of-state resources are summarized in Table 39. No out-of-state resources are available prior to 2026. After 2035, the full resource potentials from Section 5.2.1.4 are assumed to be available. The costs associated with specific transmission projects that inform these availability assumptions are discussed in Section 5.5.4.

*Table 39. Out-of-state wind and geothermal annual build limits, MW*

| Resource | | 2026 | 2028 | 2030 | 2032 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|
| Wind | Idaho_Wind | 0 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 |
| | New_Mexico_Wind | 2,500 | 2,500 | 4,000 | 4,000 | 4,000 | 5,500 |
| | Utah_Wind | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wyoming_Wind | 0 | 1,500 | 3,000 | 3,000 | 3,000 | 4,000 |
| | **Total** | **2,500** | **5,100** | **8,100** | **8,100** | **8,100** | **10,600** |
| Geothermal | Central_Nevada_Geothermal | 0 | 0 | 596 | 596 | 596 | 596 |
| | Northern_Nevada_Geothermal | 0 | 0 | 855 | 855 | 855 | 855 |
| | Pacific_Northwest_Geothermal | 0 | 520 | 520 | 520 | 520 | 520 |
| | Utah_Geothermal | 0 | 0 | 0 | 0 | 0 | 0 |
| | **Total** | **0** | **520** | **1,971** | **1,971** | **1,971** | **1,971** |

#### *5.2.2.4 Offshore Wind Availability*

The availability of offshore wind reflects an 8- to 10-year lead time and prioritization of the Morro Bay and Humboldt Wind Energy Areas because they are the only resource areas officially recognized by BOEM and for which there are now active leases.

*Table 40. Offshore wind first available years*

| Resource | First Available Year |
|---|---|
| Morro_Bay_Offshore_Wind | 2032 |
| Humboldt_Offshore_Wind | 2034 |
| Cape_Mendocino_Offshore_Wind | 2039 |
| Del_Norte_Offshore_Wind | 2039 |

### 5.2.3 Resource Cost

NREL's Annual Technology Baseline is used as the primary basis for renewable generation cost updates. The assumptions for RESOLVE renewable resources are shown in the tables below for in-state, out-of-state, and offshore wind resources, respectively. The input to RESOLVE is an assumed levelized fixed cost ($/kW-yr) for each resource for the year the resource comes online; this is translated into the levelized cost of electricity ($/MWh) for comparability. The capacity factors used for this conversion are discussed in Section 6.2. The costs reported below reflect modifications to solar, onshore wind, and offshore wind technology costs, which are discussed in Sections 5.2.3.1, 5.2.3.2, and 5.2.3.3. Incremental costs due to new transmission lines, including long-distance transmission lines for out-of-state resources, are excluded from the results in the following tables (see Section 5.5). The costs in these tables reflect monetization of the full "Bonus" tax credit incentives under the IRA.

*Table 41. In-state (CAISO-interconnecting) renewable resource cost assumptions by build year*

| | Resource | Capacity Factor | Capital Cost (2022 $/kW) | | | | Levelized Cost of Electricity (2022 $/MWh) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2025 | 2030 | 2035 | 2040 | 2025 | 2030 | 2035 | 2040 |
| Biomass | InState_Biomass | 85% | $5,478 | $5,223 | $5,049 | $4,870 | $280 | $279 | $278 | $277 |
| Geothermal | Greater_Imperial_Geothermal | 80% | $7,251 | $6,642 | $6,231 | $6,077 | $75 | $72 | $68 | $67 |
| | Inyokern_North_Kramer_Geothermal | 80% | $7,257 | $6,647 | $6,235 | $6,081 | $76 | $73 | $69 | $68 |
| | Northern_California_Geothermal | 80% | $7,257 | $6,647 | $6,235 | $6,081 | $76 | $73 | $69 | $68 |
| Solar | Arizona_Solar | 33% | $1,494 | $1,357 | $1,130 | $902 | $31 | $28 | $22 | $16 |
| | Distributed_Solar | 24% | $2,233 | $1,857 | $1,481 | $1,357 | $78 | $69 | $58 | $54 |
| | Greater_Imperial_Solar | 34% | $1,538 | $1,397 | $1,163 | $928 | $32 | $29 | $23 | $17 |
| | Greater_Kramer_Solar | 35% | $1,532 | $1,392 | $1,158 | $925 | $31 | $28 | $22 | $16 |
| | Greater_LA_Solar | 32% | $1,540 | $1,400 | $1,165 | $930 | $36 | $33 | $26 | $20 |
| | Northern_California_Solar | 28% | $1,540 | $1,400 | $1,165 | $930 | $43 | $39 | $32 | $25 |
| | Riverside_Solar | 34% | $1,536 | $1,395 | $1,161 | $927 | $32 | $29 | $23 | $17 |
| | Southern_NV_Eldorado_Solar | 33% | $1,484 | $1,348 | $1,122 | $896 | $29 | $26 | $20 | $15 |
| | Southern_PGAE_Solar | 32% | $1,538 | $1,397 | $1,163 | $929 | $34 | $31 | $25 | $18 |
| | Tehachapi_Solar | 35% | $1,540 | $1,400 | $1,165 | $930 | $31 | $28 | $22 | $16 |
| Wind | Baja_California_Wind | 30% | $1,638 | $1,348 | $1,223 | $1,162 | $47 | $40 | $36 | $34 |
| | Central_Valley_North_Los_Banos_Wind | 24% | $1,703 | $1,402 | $1,272 | $1,209 | $66 | $56 | $51 | $49 |
| | Greater_Imperial_Wind | 30% | $1,706 | $1,405 | $1,274 | $1,211 | $48 | $40 | $36 | $34 |
| | Northern_California_Wind | 22% | $1,706 | $1,405 | $1,274 | $1,211 | $75 | $64 | $58 | $56 |
| | Solano_Wind | 26% | $1,706 | $1,405 | $1,274 | $1,211 | $60 | $51 | $46 | $44 |
| | Southern_NV_Eldorado_Wind | 33% | $1,663 | $1,369 | $1,242 | $1,181 | $42 | $35 | $31 | $30 |
| | Tehachapi_Wind | 29% | $1,706 | $1,405 | $1,274 | $1,211 | $52 | $44 | $40 | $38 |

*Table 42. Out-of-state renewable resource cost assumptions by build year*

| | Resource | Capacity Factor | Capital Cost (2022 $/kW) | | | | Levelized Cost of Electricity (2022 $/MWh) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2025 | 2030 | 2035 | 2040 | 2025 | 2030 | 2035 | 2040 |
| Geothermal | Central_Nevada_Geothermal | 80% | $6,984 | $6,398 | $6,001 | $5,853 | $72 | $69 | $65 | $64 |
| | Northern_Nevada_Geothermal | 80% | $6,984 | $6,398 | $6,001 | $5,853 | $72 | $69 | $65 | $64 |
| | Pacific_Northwest_Geothermal | 80% | $7,209 | $6,604 | $6,195 | $6,041 | $75 | $72 | $68 | $67 |
| | Utah_Geothermal | 80% | $6,977 | $6,391 | $5,995 | $5,847 | $72 | $69 | $65 | $64 |
| Wind | Idaho_Wind | 34% | $1,658 | $1,365 | $1,238 | $1,177 | $40 | $34 | $30 | $29 |
| | New_Mexico_Wind | 46% | $1,651 | $1,360 | $1,233 | $1,172 | $24 | $19 | $17 | $16 |
| | Utah_Wind | 35% | $1,662 | $1,369 | $1,241 | $1,180 | $38 | $32 | $29 | $27 |
| | Wyoming_Wind | 49% | $1,662 | $1,368 | $1,241 | $1,180 | $22 | $17 | $15 | $14 |

*Table 43. Offshore wind resource cost assumptions by build year. Capital cost is exclusive of grid connection costs. Offshore wind is not available for selection until the 2030s (see Section 5.2.2.4).*

| | Resource | Capacity Factor | Capital Cost (2022 $/kW) | | | | Levelized Cost of Electricity (2022 $/MWh) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2025 | 2030 | 2035 | 2040 | 2025 | 2030 | 2035 | 2040 |
| Offshore Wind | Morro_Bay_Offshore_Wind | 46% | $5,084 | $4,072 | $3,756 | $3,561 | $102 | $86 | $79 | $74 |
| | Humboldt_Bay_Offshore_Wind | 58% | $5,084 | $4,072 | $3,756 | $3,561 | $81 | $68 | $63 | $59 |
| | Cape_Mendocino_Offshore_Wind | 59% | $5,084 | $4,072 | $3,756 | $3,561 | $79 | $66 | $61 | $57 |
| | Del_Norte_Offshore_Wind | 57% | $5,084 | $4,072 | $3,756 | $3,561 | $82 | $70 | $64 | $60 |

#### 5.2.3.1 Solar Cost Assumptions

NREL 2023 ATB is used to determine both capital costs and operating costs of solar PV resources for each forecast year. Both utility-scale and distributed solar PV cost projections use ATB data.

Three capital cost trajectories are developed based on the Technology Innovation Scenarios in NREL 2023 ATB.[81] The "Low" case corresponds to the ATB "Advanced" scenario and follows a more ambitious trajectory enabled by increased R&D funding and widespread technology innovations that are not market-ready today. The "Mid" case corresponds to the ATB "Moderate" scenario, which represents an expected level of technology innovation and assumes continuation of current levels of R&D funding. The "High" case corresponds to the ATB "Conservative" scenario and assumes few changes in current technology and reduced R&D funding.

As discussed in Section 4.4, modifications to the ATB cost trajectory for utility-scale solar were made to reflect current market conditions and substantial impacts to the supply chain. Specifically, the overnight capital cost trajectories from NREL 2023 ATB were delayed through 2027, as shown in Figure 6 below.

[81] NREL ATB's Technology Innovation Scenarios can be found on the NREL 2023 ATB website: https://atb.nrel.gov/electricity/2023/definitions.

*Figure 6. Utility-scale solar capex trajectories before and after modification*

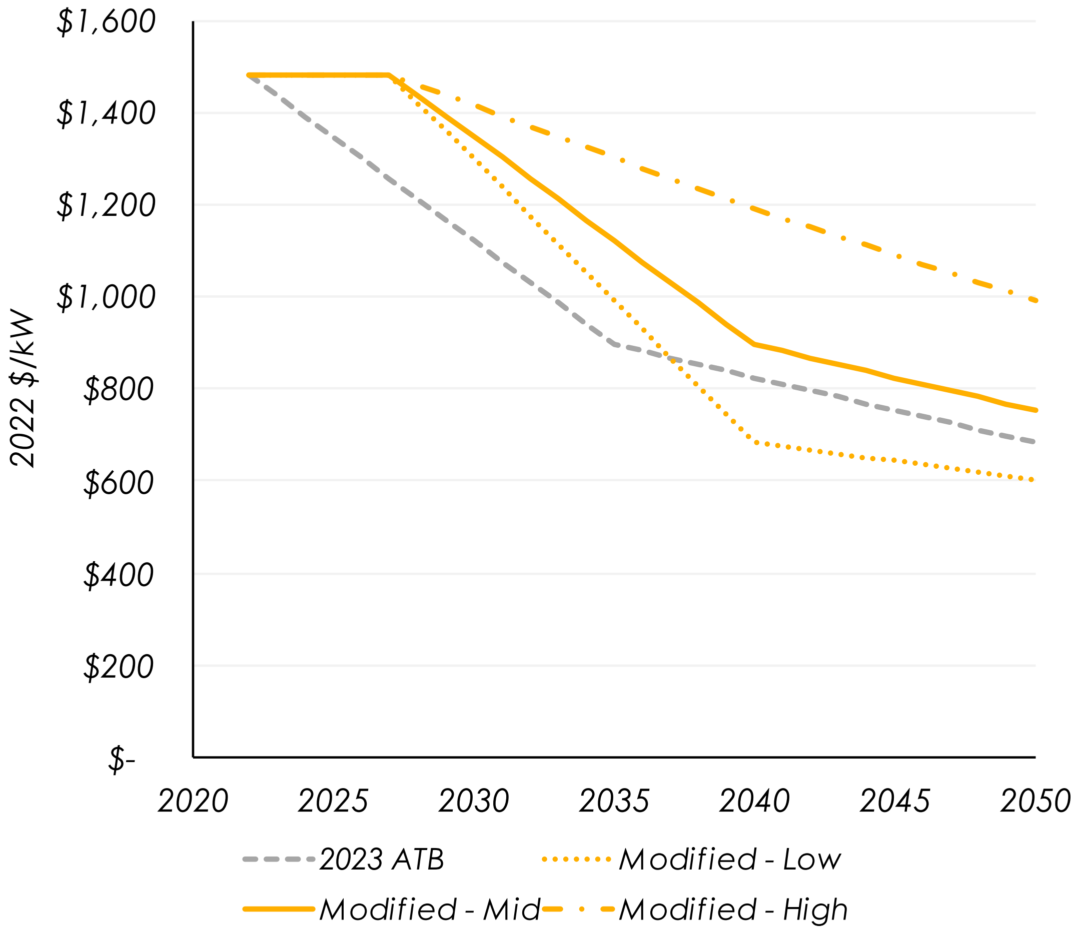


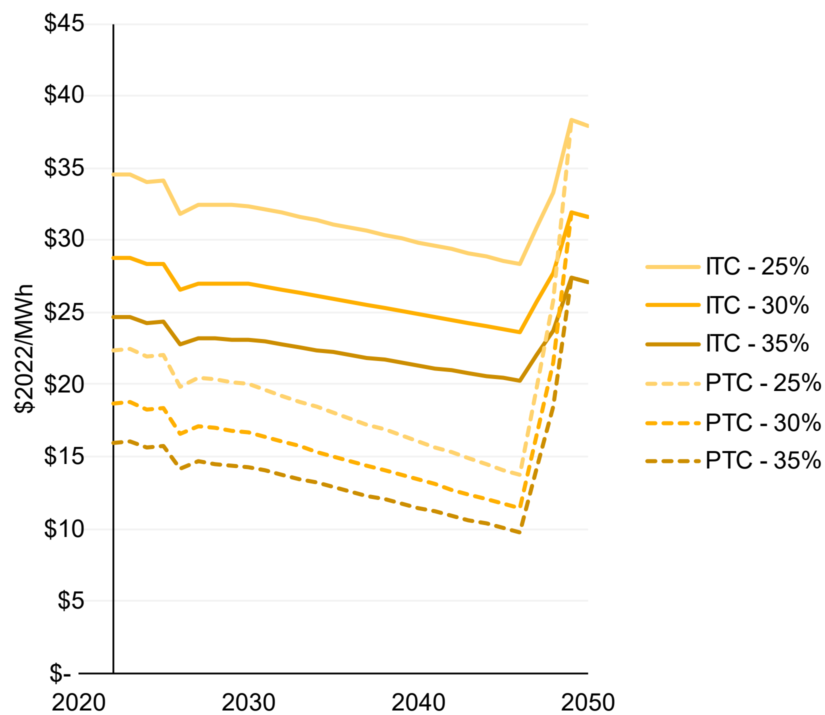

*Table 44. Modified cost trajectories for utility-scale solar PV (% of 2022 capital cost)*

| RESOLVE Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| Low | 100% | 100% | 96% | 88% | 67% | 46% | 43% |
| Mid | 100% | 100% | 97% | 91% | 76% | 60% | 56% |
| High | 100% | 100% | 98% | 95% | 88% | 80% | 74% |

ATB cost data is location-independent (developed to be free of geographical factors) and regional adjustments are made to reflect California and out-of-state conditions, if material. Cost calculations assume a single-axis tracking system with a 1.3 inverter loading ratio for utility-scale solar based on NREL 2023 ATB, and a fixed-tilt system with 1.15 inverter loading ratio for distributed solar based on Lawrence Berkeley National Laboratory's 2019 *Tracking the Sun* study.[82,83]

For the 2022-2023 IRP cycle, due to the Inflation Reduction Act (IRA), solar PV can elect to receive a Production Tax Credit (PTC) in lieu of the Investment Tax Credit (ITC). Early analysis indicates that the PTC will outperform the ITC on a levelized cost of electricity (LCOE) basis for utility-scale projects operating within the range of capacity factors expected for single-axis tracking projects installed in California (Figure 7). Consequently, new candidate solar generators are assumed to receive the PTC in the upcoming IRP cycle.

*Figure 7. Illustrative levelized cost of energy for utility-scale solar receiving the IRA "Bonus" Investment Tax Credit (ITC) or Production Tax Credit (PTC) at various capacity factors.*




[82] https://atb.nrel.gov/electricity/2023/utility-scale_pv.

[83] "Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States." Lawrence Berkeley National Laboratory, 2019. https://emp.lbl.gov/sites/default/files/tracking_the_sun_2019_report.pdf.

#### 5.2.3.2 Onshore Wind Cost Assumptions

NREL 2023 ATB also provides estimates of onshore wind costs. ATB provides capital expenditure (CAPEX) and fixed O&M values for wind, as well as three Technology Innovation Scenarios, i.e., Advanced, Moderate, and Conservative, which are used to the develop the Low, Mid, and High cost trajectories for RESOLVE modeling. NREL 2023 ATB classifies wind resources into ten classes based on annual mean wind speed. The CAPEX and fixed O&M values are the same across the ten wind speed classes within each Technology Innovation Scenario.

As discussed in Section 4.4, modifications to the ATB cost trajectory for onshore wind were made to reflect current market conditions and substantial impacts to the supply chain. Specifically, the overnight capital cost trajectories from NREL 2023 ATB were delayed through 2027, as shown in the chart below.

*Figure 8. Onshore wind capex trajectories before and after modification*

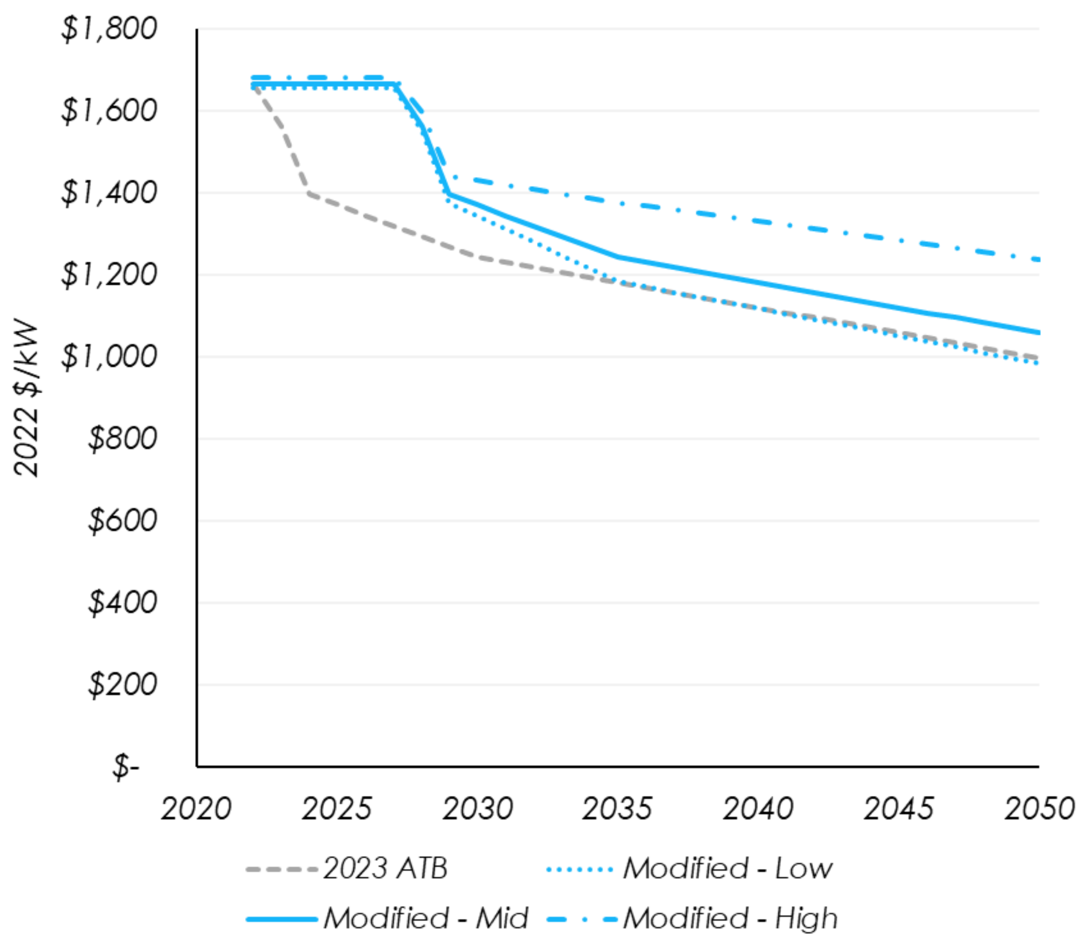


*Table 45. Modified cost trajectories for onshore wind (% of 2022 capital cost)*

| RESOLVE Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| Low | 100% | 100% | 94% | 81% | 71% | 67% | 63% |
| Mid | 100% | 100% | 94% | 82% | 75% | 71% | 67% |
| High | 100% | 100% | 95% | 85% | 82% | 79% | 76% |

#### *5.2.3.3 Offshore Wind Cost Assumptions*

As discussed in Section 4.2, offshore wind costs are derived from two data sources. NREL 2023 ATB is used for overnight capital cost and fixed O&M assumptions, while the site-specific 2020 NREL report on floating offshore wind costs (OCS Study BOEM 2020-048)[84] is used for grid connection costs. Low, Mid, and High cost scenarios are also included in the NREL OCS Study to reflect the uncertainty of future offshore wind deployment and associated cost reductions.

As discussed in Section 4.4, modifications to the ATB cost trajectory for offshore wind were made to reflect current market conditions and substantial impacts to the supply chain. Specifically, the overnight capital cost trajectories from NREL 2023 ATB were delayed through 2027, as shown in the chart below.

[84] https://www.nrel.gov/docs/fy21osti/77384.pdf

*Figure 9. Offshore wind capex trajectories before and after modification*

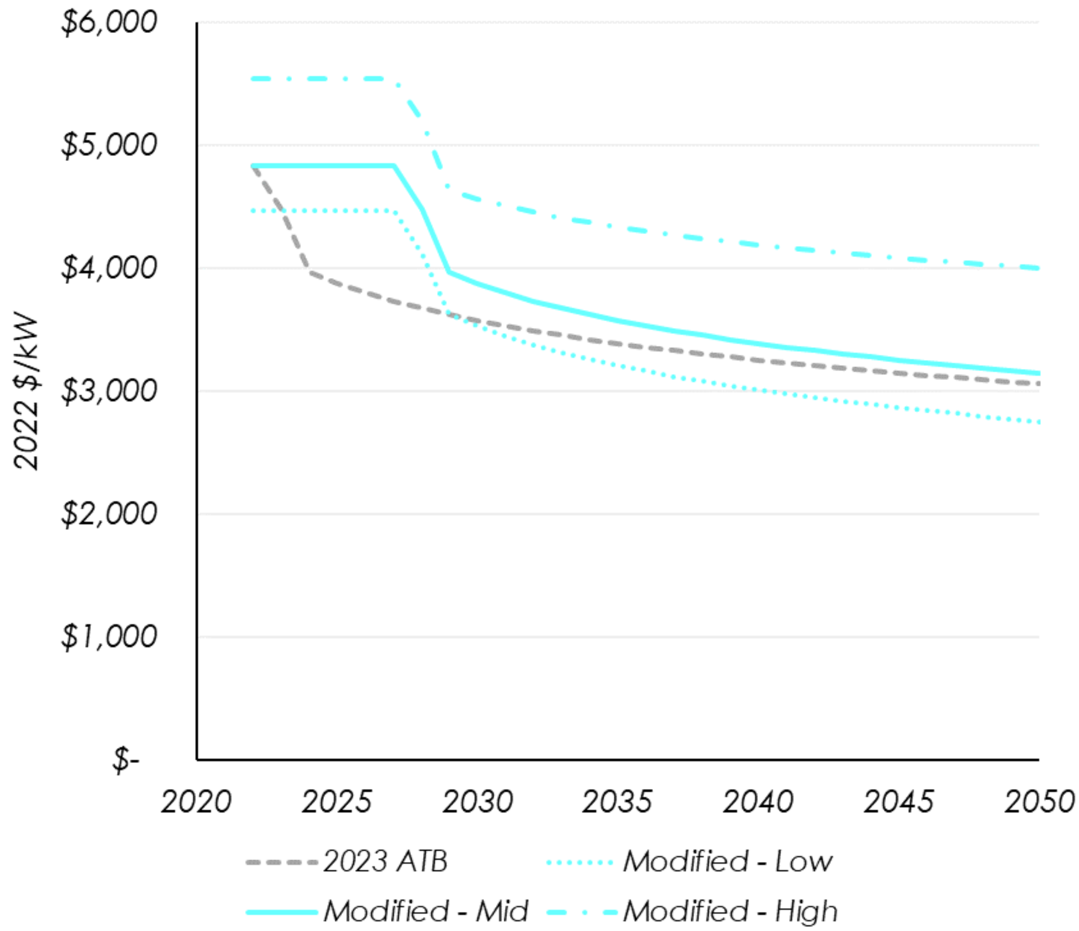



*Table 46. Cost trajectories for offshore wind (% of 2022 capital cost)*

| RESOLVE Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| Low | 100% | 100% | 92% | 79% | 72% | 67% | 64% |
| Mid | 100% | 100% | 93% | 80% | 74% | 70% | 67% |
| High | 100% | 100% | 94% | 82% | 78% | 76% | 74% |

## 5.3 Energy Storage

Energy storage cost and performance characteristics can vary significantly by technical configuration and use case. To flexibly model energy storage systems of differing sizes and durations, the cost of storage is broken into two components (to the extent that this data is available): capacity (or power, $/kW) and energy (or duration, $/kWh). The capacity cost refers to all costs that scale with the rated installed power (kW) while the energy cost refers to all costs that scale with the energy (kWh) or storage duration (hr) of the storage resource. This breakout is intended to capture the different drivers of storage system costs. For example, a 1 kW battery system would require the same size inverter whether it is a four- or six-hour battery but would require additional cells in the longer duration case.

For pumped storage, capacity costs are the largest fraction of total system cost and include the costs of the turbines, penstocks, interconnection, etc., while energy costs are relatively small and mainly cover the costs of preparing the reservoir. For Li-ion batteries, capacity costs include the cost of the inverter and other power electronics for the interconnection, while the energy costs include the Li-ion battery cells. For flow batteries, capacity costs include the cost of the inverter and other power electronics, as well as the ion exchange membrane and fluids pumps, while the energy costs consist of the tanks and the electrolyte. As a result, the capacity component of flow battery costs is higher than that of Li-ion, while the energy component is lower.

New to the 2022-23 IRP cycle, energy storage resources are modeled as having fixed durations. This update was made to reflect the practical deployment of energy storage systems, as well as facilitate ELCC modeling for a wider array of energy storage technologies (Sections 7.1.9 and 7.1.10). For Li-ion batteries, both 4- and 8-hour duration systems will be modeled. For pumped storage, 12 hours of duration is assumed.

### 5.3.1 Pumped Storage

The capital costs of candidate pumped storage resources for the 2022-2023 IRP cycle are derived from NREL 2023 ATB, Technology Class 8. Pumped storage costs in NREL 2023 ATB are represented as a single cost in $/kW, for an assumed storage duration of 10 hours.[85] In RESOLVE, candidate pumped storage resources are modeled at a 12-hour duration. The ATB costs are assumed to be valid at 12 hours of duration due to the geographical specificity of the pumped hydro storage resource potential. No learning curve is applied to the NREL ATB costs, and consequently the overnight capital cost and fixed O&M trajectories are flat.

*Table 47. Pumped storage cost components (2022 $)*

| Cost Component | Capital Cost – Total, 12-Hour Storage ($/kW) | Fixed O&M Cost ($/kW-yr) |
|---|---|---|
| Pumped Hydro Storage | $3,647 | $20 |

[85] https://atb.nrel.gov/electricity/2023/pumped_storage_hydropower.

These capital costs are fed into a pro forma model (Section 4.1) to estimate levelized fixed costs, using the following assumptions:

- Financing lifetime of 50 years
- Fixed O&M of $20/kW-yr with an annual escalation of 2%
- No variable O&M costs
- After-tax WACC of 8.1%.

The resulting all-in levelized fixed costs are shown below.

*Table 48. Pumped storage all-in levelized fixed costs (2022 $)*

| Cost Component | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|
| Levelized Fixed Cost ($/kW) | $190 | $194 | $198 | $198 | $198 | $198 | $198 | $198 |

The pumped storage resource potential assumptions are shown in the table below. These results were determined by internal CPUC analysis of the estimated online dates of identified potential projects in California and in the CAISO interconnection queue and permitting applications to FERC.

*Table 49. Available potential by year (MW) for candidate pumped storage resources.*

| | 2026 | 2028 | 2030 | 2032 | 2033 | 2035 |
|---|---|---|---|---|---|---|
| Pumped Storage | - | 2,173 | 2,673 | 3,173 | 3,173 | 3,173 |

### 5.3.2 Battery Storage

Battery storage costs are attributed to either the system's rated capacity ($/kW) or energy storage ($/kWh). The types of costs included in each category are summarized below:

- Capacity (kW): Inverter, switches and breakers, other balance of system and Engineering, procurement, and construction (EPC) costs
- Energy (kWh): Battery cell modules, racking frame/cabinet, battery management system

The total cost of an energy storage system is calculated by summing its capacity cost with the product of its duration and energy cost:

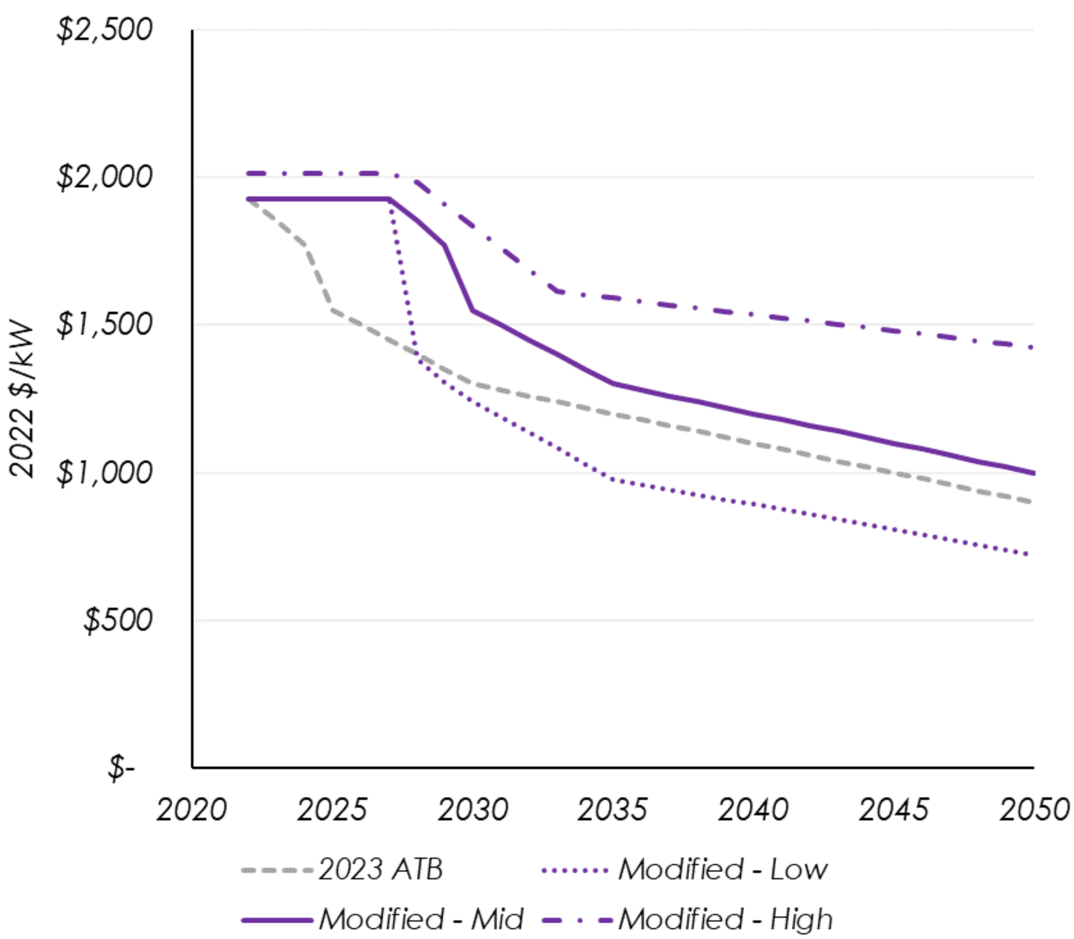
$$Total\ Cost\ \left(\frac{\$}{kW}\right) = Capacity\ Cost\ \left(\frac{\$}{kW}\right) + \left(Duration\ (hr) * Energy\ Cost\ \left(\frac{\$}{kWh}\right)\right)$$

RESOLVE includes both utility-scale and BTM battery storage as candidate resources. Both Li-ion and flow battery technologies are included as candidate utility-scale battery storage resources, while candidate BTM battery storage is assumed to be Li-ion technology. New to the 2022-2023 IRP cycle, both utility-scale and BTM Li-ion battery storage relies on storage cost assumptions from NREL ATB. Utility-scale flow battery storage uses the PNNL Energy Storage Grand Challenge (ESGC) Cost and Performance Database for its cost assumptions.

Under the IRA, standalone battery storage can receive the ITC. As a result, the cost benefits of paired battery storage relative to standalone battery storage are diminished. For this reason, paired and hybrid battery storage technologies are not modeled in RESOLVE.

As discussed in Section 4.4, modifications to the ATB cost trajectory for utility-scale Li-ion batteries were made to reflect current market conditions and substantial impacts to the supply chain. Specifically, the overnight capital cost trajectories from NREL 2023 ATB were delayed through 2027, as shown in the chart below.

*Figure 10. Li-ion battery capex trajectories before and after modification*




Given the uncertainty regarding future battery costs, the 2022-2023 IRP cycle inputs include Low-, Mid- and High-cost options to reflect a range of potential cost trajectories. In addition to breaking out capital costs between capacity and energy, different O&M costs are attributed to each of these categories. For example, augmentation costs are assumed to cover battery cell performance, thus are attributed to the energy cost category.

*Table 50. Capital cost assumptions for candidate battery resources (2022 $)*

| Resource | Cost Component | Case | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|---|
| **Li-Ion Battery (Utility-Scale)** | Capital Cost – Capacity ($/kW) | Low | $363 | $233 | $184 | $167 |
| | | Mid | $363 | $311 | $317 | $306 |
| | | High | $379 | $360 | $333 | $322 |
| | Capital Cost – Energy ($/kWh) | Low | $391 | $252 | $199 | $181 |
| | | Mid | $391 | $310 | $246 | $223 |
| | | High | $408 | $369 | $314 | $303 |
| | Fixed O&M (% Capacity Cost) | All | 2.50% | 2.50% | 2.50% | 2.50% |
| **Li-Ion Battery (BTM)** | Capital Cost – Capacity ($/kW) | Low | $450 | $369 | $334 | $300 |
| | | Mid | $639 | $581 | $545 | $508 |
| | | High | $719 | $584 | $576 | $568 |
| | Capital Cost – Energy ($/kWh) | Low | $416 | $341 | $309 | $277 |
| | | Mid | $489 | $395 | $370 | $346 |
| | | High | $664 | $540 | $532 | $525 |
| | Fixed O&M (% Capacity Cost) | All | 2.50% | 2.50% | 2.50% | 2.50% |
| **Flow Battery (Utility-Scale)** | Capital Cost – Capacity ($/kW) | Low | $76 | $69 | $69 | $69 |
| | | Mid | $132 | $122 | $122 | $122 |
| | | High | $ | $ | $ | $ |
| | Capital Cost – Energy ($/kWh) | Low | $255 | $219 | $219 | $219 |
| | | Mid | $367 | $329 | $329 | $329 |
| | | High | $ | $ | $ | $ |
| | Fixed O&M ($/kW-yr) (8-hr) | Mid | $20 | $18 | $18 | $18 |

Battery capital costs are fed into a pro forma model (Section 4.1) to estimate levelized fixed costs, using the following assumptions: financing lifetime of 20 years for wholesale batteries, 10 years for BTM batteries; ITC eligibility; and after-tax WACC of 6.9%. The resulting all-in levelized fixed costs of the mid case are shown in Table 51.

*Table 51. Candidate battery levelized fixed costs – Mid (2022 $)*

| Resource | Cost Component | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| **Li-Ion Battery (Utility-Scale)** | Levelized Fixed Cost – Capacity ($/kW-yr) | $45 | $42 | $42 | $41 |
| | Levelized Fixed Cost – Energy ($/kWh-yr) | $31 | $25 | $20 | $18 |
| **Li-Ion Battery (BTM)** | Levelized Fixed Cost – Capacity ($/kW-yr) | $76 | $70 | $66 | $61 |
| | Levelized Fixed Cost – Energy ($/kWh-yr) | $58 | $48 | $45 | $42 |
| **Flow Battery (Utility-Scale)** | Levelized Fixed Cost – Capacity ($/kW-yr) | $39 | $39 | $39 | $39 |
| | Levelized Fixed Cost – Energy ($/kWh-yr) | $28 | $26 | $26 | $26 |

RESOLVE does not limit the available potential for candidate battery storage resources.

### 5.3.3 Compressed Air Energy Storage

The capital costs of adiabatic compressed air energy storage (A-CAES) resources for the 2022-2023 IRP cycle are derived from the PNNL ESGC Cost and Performance Database for a 1,000-MW, 24-hr system configuration.[86] PNNL provides cost estimates for 2021 and 2030, but no learning curve is assumed; costs are held flat. In RESOLVE, candidate A-CAES resources are modeled at a 24-hour duration.

*Table 52. Compressed air energy storage cost components (2022 $)*

| Cost Component | Capital Cost ($/kW) | Capital Cost ($/kWh) | Fixed O&M Cost ($/kW-yr) |
|---|---|---|---|
| A-CAES | $1,146 | $43 | $11 |

These capital costs are fed into a pro forma model (Section 4.1) to estimate levelized fixed costs, using the following assumptions:

[86] https://www.pnnl.gov/compressed-air-energy-storage-caes.

- Financing lifetime of 35 years
- Fixed O&M of $11/kW-yr with an annual escalation of 2%
- No variable O&M costs
- After-tax WACC of 9.3%.

The resulting all-in levelized fixed costs are shown below.

*Table 53. Adiabatic compressed air energy system all-in levelized fixed costs (2022 $)*

| Cost Component | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|
| Capacity ($/kW-yr) | $103 | $105 | $106 | $106 | $106 | $106 | $106 | $106 |
| Energy ($/kWh-yr) | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 |

The A-CAES resource potential assumptions are shown in the table below. These results were determined by internal CPUC analysis of the estimated online dates of identified potential projects in California and in the CAISO interconnection queue and permitting applications to FERC.

*Table 54. Available potential by year (MW) for candidate adiabatic compressed air energy systems*

| | 2026 | 2028 | 2030 | 2032 | 2033 | 2035 |
|---|---|---|---|---|---|---|
| A-CAES | - | 900 | 900 | 900 | 900 | 900 |

## 5.4 Minimum Build Constraints

Generators tagged as "Planned/New" or "Planned/Review" in the 11/1/2022 LSE filings[87] are interpreted as minimum build constraints for candidate resources and technologies in the RESOLVE scenarios that force in these plans. The LSEs filed plans for both 25 MMT and 30 MMT carbon reduction target scenarios. As a result, two sets of constraints exist depending on the carbon reduction target scenario being modeled in RESOLVE. The LSE filings identify both specific resource plans (e.g., Arizona_Solar) and generic plans (e.g., Generic Solar PV); consequently, both regional- and technology-level minimum build constraints are used in RESOLVE. The technology minimum build amounts are inclusive of all regional minimum builds.

[87] Aggregated 2022 LSE Plan Baseline and Development Resources. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/aggregated-lse-plans-and-baseline-resources-2023-psp.xlsx

LSE plans for Li-ion batteries are binned by duration. Systems with duration less than 6 hours are counted towards the CAISO_Li_Battery_4hr_Dispatch minimum build constraint, while those with durations greater than or equal to 6 hours are counted towards the CAISO_Li_Battery_8hr_Dispatch minimum build constraint.

Some LSE plans call for new resource additions of technologies that are not modeled as candidate resource options in RESOLVE. Planned biogas additions are assumed to count towards the biomass minimum build constraint. Planned hydro additions are assumed to count towards the pumped hydro minimum build constraint. One planned resource is labeled as CCGT but is known to be a small, 8-hr Li-ion battery co-located with an existing gas plant; this resource is assumed to count towards the 8-hr Li-ion battery minimum build constraint. Finally, SMUD and LADWP's filings were excluded since RESOLVE does not model capacity expansion in non-CAISO zones.

In instances where the available resource potential (Section 5.2.1) and/or first available years and annual build limits (Section 5.2.2) contradict the LSE planned resource additions, those other constraints are preserved, and the minimum build constraints are adjusted. Such conditions were found for wind, geothermal, and offshore wind minimum build constraints. Additionally, due to mismatching data vintages, the CAISO transmission constraints (Section 5.5) were found to conflict with the geothermal minimum build constraint. The LSE plans for geothermal in 2026 were relaxed to ensure that no resources were being forced into the model that could not be placed on the CAISO transmission system.

For offshore wind, only a technology-wide minimum build constraint is represented in RESOLVE. The site-specificity of the LSE plans is being suppressed because the resource potentials and first available years (Section 5.2) of the offshore wind resources do not align well with the LSE plans. The minimum build constraints in each year are capped at the aggregated available offshore wind resource potential to avoid model infeasibility.

Some LSE plans call for energy-only resources. However, due to stipulations that only in-state wind and solar be made eligible for Energy Only Deliverability Status (EODS) status (Section 5.5), most of those planned resource additions are modeled as Full Capacity Deliverability Status (FCDS) instead. Two minimum build constraints for energy-only solar resource additions and one for energy-only wind are modeled in RESOLVE by carving out resource potential for these build assets from Northern California and Southern NV Eldorado.

The LSE minimum build constraints through 2035 are summarized in the tables below.

*Table 55. Technology Minimum Build Constraints, 25 MMT*

| Technology | 2024 | 2025 | 2026 | 2028 | 2030 | 2035 |
|---|---|---|---|---|---|---|
| A-CAES | - | - | - | 200 | 200 | 200 |
| Biomass | - | - | - | 171 | 171 | 171 |
| Geothermal | - | - | 783 | 1,143 | 1,543 | 1,639 |
| Li-ion Battery (4-hr) | 3,989 | 6,284 | 7,996 | 9,028 | 11,581 | 15,707 |
| Li-ion Battery (8-hr) | 8 | 14 | 526 | 1,058 | 1,339 | 3,142 |
| Offshore Wind | - | - | - | - | - | 4,531 |
| Pumped Hydro | - | - | - | 477 | 477 | 477 |
| Shed DR | - | - | - | - | - | - |
| Solar | 1,266 | 4,097 | 5,539 | 8,528 | 14,781 | 18,988 |
| Wind | 325 | 1,045 | 2,495 | 4,488 | 6,913 | 7,647 |

*Table 56. Technology Minimum Build Constraints, 30 MMT*

| Technology | 2024 | 2025 | 2026 | 2028 | 2030 | 2035 |
|---|---|---|---|---|---|---|
| A-CAES | - | - | - | 200 | 200 | 200 |
| Biomass | - | - | - | 171 | 171 | 171 |
| Geothermal | - | - | 783 | 1,140 | 1,523 | 1,619 |
| Li-ion Battery (4-hr) | 3,989 | 6,284 | 7,996 | 9,028 | 10,983 | 16,136 |
| Li-ion Battery (8-hr) | 8 | 14 | 526 | 1,058 | 1,312 | 1,952 |
| Offshore Wind | - | - | - | - | - | 4,648 |
| Pumped Hydro | - | - | - | 477 | 477 | 477 |
| Shed DR | - | - | - | - | - | - |
| Solar | 1,260 | 4,091 | 5,534 | 8,349 | 12,614 | 17,466 |
| Wind | 325 | 1,045 | 2,495 | 4,132 | 6,789 | 7,640 |

*Table 57. Resource Minimum Build Constraints, 25 MMT*

| Resource | 2024 | 2025 | 2026 | 2028 | 2030 | 2035 |
|---|---|---|---|---|---|---|
| Arizona_Solar | - | - | - | 169 | 169 | 169 |
| Baja_California_Wind | - | - | - | 111 | 111 | 111 |
| Central_Nevada_Geothermal | - | - | - | - | 40 | 40 |
| Central_Valley_North_Los_Banos_Wind | - | - | - | 32 | 32 | 32 |
| Greater_Imperial_Geothermal | - | - | - | - | 111 | 111 |
| Greater_Imperial_Solar | - | - | - | - | 39 | 39 |
| Greater_Kramer_Li_Battery_8hr | - | - | - | - | 100 | 100 |
| Greater_Kramer_Solar | - | - | - | 769 | 819 | 819 |
| Idaho_Wind | - | - | - | 100 | 300 | 300 |
| New_Mexico_Wind | - | - | 800 | 1,486 | 1,968 | 1,968 |
| Northern_California_Geothermal | - | - | - | 3 | 48 | 88 |
| Northern_California_Li_Battery_4hr | 3 | 3 | 8 | 8 | 9 | 14 |
| Northern_California_Solar | 7 | 13 | 18 | 18 | 21 | 26 |
| Northern_California_Wind | - | - | - | 200 | 549 | 549 |
| Pacific_Northwest_Geothermal | - | - | - | 13 | 13 | 13 |
| Riverside_Solar | - | - | - | 659 | 659 | 659 |
| Solano_Wind | - | - | - | 104 | 104 | 104 |
| Southern_NV_Eldorado_Li_Battery_4h | - | - | 94 | 94 | 94 | 94 |
| Southern_NV_Eldorado_Solar | - | - | 189 | 189 | 189 | 189 |
| Southern_NV_Eldorado_Wind | - | - | 60 | 60 | 142 | 142 |
| Southern_PGAE_Li_Battery_4hr | - | - | - | 125 | 125 | 125 |
| Southern_PGAE_Solar | - | 27 | 72 | 197 | 247 | 247 |
| Tehachapi_Li_Battery_4hr | - | - | - | - | - | 50 |
| Tehachapi_Solar | - | - | - | 554 | 554 | 654 |
| Tehachapi_Wind | - | - | - | 51 | 156 | 156 |
| Wyoming_Wind | - | - | - | 501 | 601 | 731 |

*Table 58. Resource Minimum Build Constraints, 30 MMT*

| Resource | 2024 | 2025 | 2026 | 2028 | 2030 | 2035 |
|---|---|---|---|---|---|---|
| Arizona_Solar | - | - | - | 134 | 134 | 134 |
| Baja_California_Wind | - | - | - | 126 | 126 | 126 |
| Central_Nevada_Geothermal | - | - | - | - | 40 | 40 |
| Central_Valley_North_Los_Banos_Wind | - | - | - | 36 | 36 | 36 |
| Greater_Imperial_Geothermal | - | - | - | - | 94 | 94 |
| Greater_Imperial_Solar | - | - | - | - | 39 | 39 |
| Greater_Kramer_Li_Battery_8hr | - | - | - | - | 100 | 100 |
| Greater_Kramer_Solar | - | - | - | 468 | 518 | 518 |
| Idaho_Wind | - | - | - | 100 | 300 | 300 |
| New_Mexico_Wind | - | - | 800 | 1,513 | 1,923 | 1,995 |
| Northern_California_Geothermal | - | - | - | 3 | 48 | 88 |
| Northern_California_Li_Battery_4hr | 3 | 3 | 8 | 8 | 9 | 14 |
| Northern_California_Solar | 7 | 13 | 18 | 18 | 21 | 26 |
| Northern_California_Wind | - | - | - | 200 | 572 | 572 |
| Pacific_Northwest_Geothermal | - | - | - | 10 | 10 | 10 |
| Riverside_Solar | - | - | - | 749 | 749 | 749 |
| Solano_Wind | - | - | - | 118 | 118 | 118 |
| Southern_NV_Eldorado_Li_Battery_4hr | - | - | 94 | 94 | 94 | 94 |
| Southern_NV_Eldorado_Solar | - | - | 189 | 189 | 189 | 189 |
| Southern_NV_Eldorado_Wind | - | - | 60 | 60 | 118 | 118 |
| Southern_PGAE_Li_Battery_4hr | - | - | - | 125 | 125 | 125 |
| Southern_PGAE_Solar | - | 27 | 72 | 197 | 247 | 247 |
| Tehachapi_Li_Battery_4hr | - | - | - | - | - | 50 |
| Tehachapi_Solar | - | - | - | 626 | 626 | 726 |
| Tehachapi_Wind | - | - | - | 58 | 163 | 163 |
| Wyoming_Wind | - | - | - | 70 | 661 | 791 |

*Table 59. Energy Only Minimum Build Constraints, 25 MMT*

| Build Asset | 2024 | 2025 | 2026 | 2028 | 2030 | 2035 |
|---|---|---|---|---|---|---|
| Northern_California_Wind_5_EO | - | - | - | - | 299 | 299 |
| Southern_NV_Eldorado_Solar_2_EO | - | - | - | - | 329 | 329 |
| Northern_California_Solar_5_EO | - | - | - | - | 101 | 101 |

*Table 60. Energy Only Minimum Build Constraints, 30 MMT*

| Build Asset | 2024 | 2025 | 2026 | 2028 | 2030 | 2035 |
|---|---|---|---|---|---|---|
| Northern_California_Wind_5_EO | - | - | - | - | 299 | 299 |
| Southern_NV_Eldorado_Solar_2_EO | - | - | - | - | 478 | 478 |
| Northern_California_Solar_5_EO | - | - | - | - | 101 | 101 |

## 5.5 CAISO Transmission Representation

With each IRP cycle, CAISO provides transmission capability and cost estimates for use in IRP modeling.[88] The 2023 transmission capability information provided by CAISO for the 2022-23 IRP includes transmission constraint boundary diagrams,[89] a substation list for PG&E area constraints,[90] and a whitepaper with a list of electrical zones, transmission capability estimates of the existing transmission system, and the cost and capacity of potential upgrades.[91] This section focuses on the interpretation of this data set and the modeling of candidate resources on CAISO transmission constraints.

Each transmission area constraint studied by CAISO has the following components:

- Assignment to CAISO study area (e.g., PG&E Kern)
- Collection of substations (as identified in the constraint boundary diagrams) that belong to the constraint.
- The existing FCDS and EODS transmission capability estimates (in MW) on the constraint
- A proposed transmission upgrade project, with estimated construction lead time, capital cost, and incremental FCDS and EODS transmission capability (MW) delivered by the upgrade.
- Designation of the EODS constraint as a solar- or wind-type area

FCDS ("on-peak") and EODS ("off-peak") are the two types of deliverability conditions that must be satisfied on the transmission constraint. The FCDS capability estimates are used to produce two concurrent constraints in RESOLVE: the Highest System Need (HSN) constraint and Secondary System Need (SSN) constraint. Both constraints utilize the FCDS capability estimates

[88] See "Transmission capability information provided to the CPUC": http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.
[89] http://www.caiso.com/Documents/Attachment-B1-Deliverability-Constraint-Boundaries.pdf.
[90] http://www.caiso.com/Documents/Attachment-B2-PGE-Constraint-Boundary-Substation-List.xlsx.
[91] http://www.caiso.com/Documents/White-Paper-2023-Transmission-Capability-Estimates-for-use-in-the-CPUCs-Resrouce-Planning-Process.pdf.

to determine the existing and incremental constraint bounds, but new resource builds may have different contributions towards to the HSN and SSN constraints. The EODS capability estimates are used to produce the Offpeak constraint. Thus, in general, for each transmission constraint area reported by CAISO, three custom constraints must be represented in RESOLVE: HSN, SSN, and Offpeak.

Candidate resources in RESOLVE can be selected as fully deliverable (FCDS), contributing to all three transmission constraints; or energy only (EO)**,** contributing only to the Offpeak constraint. FCDS resources are included in RESOLVE's resource adequacy constraint and are counted towards system resource adequacy, as described in Section 7.1. An EO resource is excluded from RESOLVE's resource adequacy constraint, thereby not providing any resource adequacy value. The FCDS or EO status of a resource does not impact how it is represented in RESOLVE's operational module – the total installed capacity of the resource is used when simulating hourly system operations, regardless of FCDS or EO designation. Candidate geothermal, out-of-state wind, offshore wind, biomass, and energy storage resources are all required to be FCDS resources and must contribute to all three transmission constraint types. This stipulation is implemented via custom constraints in RESOLVE. Candidate distributed solar, gas-fired thermal resources, and emerging technologies are assumed to be fully deliverable on the existing transmission system and do not incur additional transmission costs. These resources are not modeled on transmission constraints.

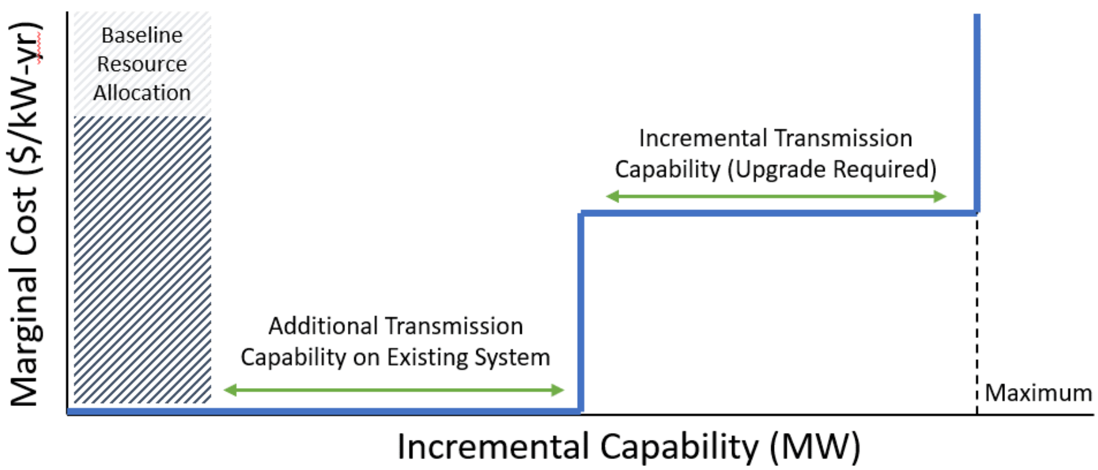
The existing transmission capabilities (FCDS and EODS) of each transmission constraint describe the amount of new resource capacity that can be installed on the existing system (i.e., without requiring upgrades). Resources within each transmission constraint compete with one another for existing, zero-marginal-cost transmission capacity. RESOLVE will typically prioritize FCDS for resources with a higher resource adequacy contribution. Once existing transmission capability (either FCDS or EODS) is exhausted on a transmission constraint, the model must invest in an upgrade to install additional resources. Generally, this will occur if the value of new transmission capacity exceeds the cost of the new transmission investment.

For most of the transmission constraints, CAISO has identified one or more upgrades that can be built to provide incremental capability. These transmission upgrades are modeled in RESOLVE as build assets, with a levelized build cost, resource potential (incremental transmission capability provided by the upgrade), and first available year (calculated using the construction lead time from 2024). Typically, when a transmission upgrade is built in the model, this upgrade will relax all three custom constraints (HSN, SSN, and Offpeak) simultaneously. New to the 2023 CAISO transmission data, some transmission upgrades have been identified that relax several constraint areas simultaneously (e.g., the new Collinsville 500 kV substation). RESOLVE has been updated to allow for a single build asset to simultaneously expand the transmission capability of multiple transmission constraints.

The transmission upgrade costs (in real $2022) published by CAISO are converted into levelized, $/kW-yr values by dividing the upgrade cost by the incremental FCDS transmission capability (or EODS capability, if the constraint does not affect FCDS deliverability), and levelizing using a capital recovery factor of 9.27%. This methodology is consistent with previous IRP cycles.

The existing transmission capabilities published in the 2023 CAISO Transmission Capability Estimates whitepaper were calculated from CAISO analysis of the electrical grid as of January 1, 2022. As such, all generators from the resource baseline (Section 3) with commercial operation dates after 1/1/2022 must have their transmission utilizations accounted for in the transmission constraints. This is accomplished by collecting the list of generators with online dates after 1/1/2022, assigning those generators to substations, identifying which constraint(s) are associated with each substation, and subtracting the generators' FCDS and EO capacities from CAISO's transmission capability estimates. Figure 11 provides a generalized view of the marginal cost and utilization of CAISO transmission constraints in RESOLVE.

*Figure 11. Conceptual diagram of transmission costs and constraint utilization for transmission constraints in RESOLVE*




In the whitepaper, CAISO identifies multiple layers of transmission constraints. These constraints are sometimes overlapping and sometimes nested, and they represent multiple concurrent limitations to delivering energy from resource areas to load centers. While only one limit may be binding at a time, all limits must be modeled simultaneously to ensure that no limits are exceeded. In RESOLVE, these constraints are modeled by partitioning each candidate resource into its constituent transmission clusters and modeling each cluster's assignment to transmission constraints separately (see Section 5.5.2). By modeling the candidate resources in this way, each resource can count towards the FCDS and EODS limits in all the transmission constraints to which it is assigned.

### 5.5.1 Transmission Resource Output Factors

Included in the 2023 CAISO Transmission Capability Estimates whitepaper are a set of resource output factors for each technology type and utility. These factors relate the installed capacity of new resource additions to their utilization of the transmission constraints. The transmission capacity utilized by a resource is equal to its installed capacity (MW) times the appropriate resource output factor. Unique factors are provided for the HSN, SSN, and Offpeak constraints. The Offpeak factors are further subdivided into wind- and solar-type area constraints. The latest resource output factors from CAISO are provided in the tables below.

*Table 61. FCDS (HSN and SSN) Resource Output Factors*

| Resource Type | HSN | | | SSN | | |
|---|---|---|---|---|---|---|
| | SDG&E | SCE | PG&E | SDG&E | SCE | PG&E |
| Solar | 3% | 10.6% | 10% | 40.2% | 42.7% | 55.6% |
| In-State Wind | 33.7% | 55.7% | 66.5% | 11.2% | 20.8% | 16.3% |
| Out-of-State Wind | 67% | | | 35% | | |
| Morro Bay OSW | 83%[92] | | | 45%[93] | | |
| Humboldt OSW | 83%[94] | | | 45%[95] | | |
| Energy Storage | 100% | | | 50% | | |
| Firm Resources | 100% | | | | | |

*Table 62. EODS Resource Output Factors by Constraint Area Type*

| Resource Type | Wind Area | | | Solar Area | | |
|---|---|---|---|---|---|---|
| | SDG&E | SCE | PG&E | SDG&E | SCE | PG&E |
| Solar | 68% | | | 79% | 77% | 79% |
| In-State Wind | 69% | 64% | 63% | 44% | | |

[92] In its August stakeholder call for the 20 Year Transmission Outlook, CAISO presented its latest updates to the offshore wind transmission output factors. These latest updates were not implemented in the modeling done before the release of this document but will be implemented in the modeling after the Ruling. The presentation can be found here. http://www.caiso.com/InitiativeDocuments/Presentation-20-Year-Transmission-Outlook-Aug-16-2023.pdf
[93] Ibid.
[94] Ibid.
[95] Ibid.

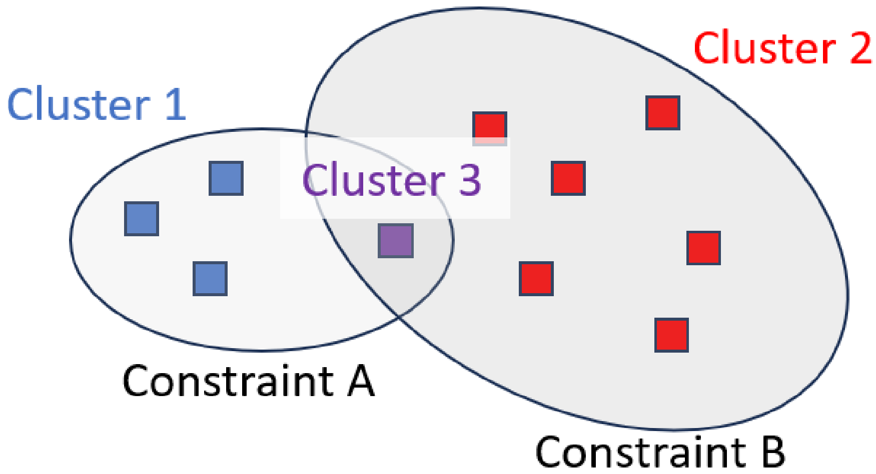
| | |
|---|---|
| Out-of-State Wind | 67% |
| Offshore Wind | 100% |
| Energy Storage | -100% (1) |
| Firm Resources | 100% |

(1) *Energy storage resources expand the transmission capability of EODS constraints.*

### 5.5.2 Clustering Methodology

For implementation into RESOLVE, the resource potentials from Section 5.2.1 are assigned to transmission constraints. To represent the CAISO transmission system more accurately in RESOLVE, and new to the 2022-23 IRP cycle, the candidate resource regions in Figure 5 (Section 5.2.1) are subdivided into **transmission clusters** via a substation-level analysis of the CAISO transmission system. Transmission clusters are geospatially localized collections of substations within CAISO that have identical memberships in the CAISO transmission constraints (see Figure 12). All substations within a transmission cluster have identical impacts on the transmission constraints defined by CAISO. Grouping the substations in this way provides a logical basis for representing the CAISO system and ensures that the complexity of nested and overlapping transmission constraints is accurately represented in RESOLVE.

*Figure 12. Schematic of a transmission system with ten substations (squares) and two constraints (ovals). These ten substations can be aggregated to form three transmission clusters (color-coded). Cluster 1 is comprised of all the substations that are only affected by Constraint A; etc.*




Granular representation of the CAISO transmission system is enabled by determining resource potential at the substation level. Using the transmission clusters as the basis for transmission representation in RESOLVE, the candidate resource potentials discussed in Sections 5.2 and 5.3 are subdivided into unique **build assets** by assigning the resource potential to individual substations. At a high level, build assets are *localized* candidate resources in RESOLVE. A build asset is the portion of a candidate resource that interconnects to a specific transmission cluster.

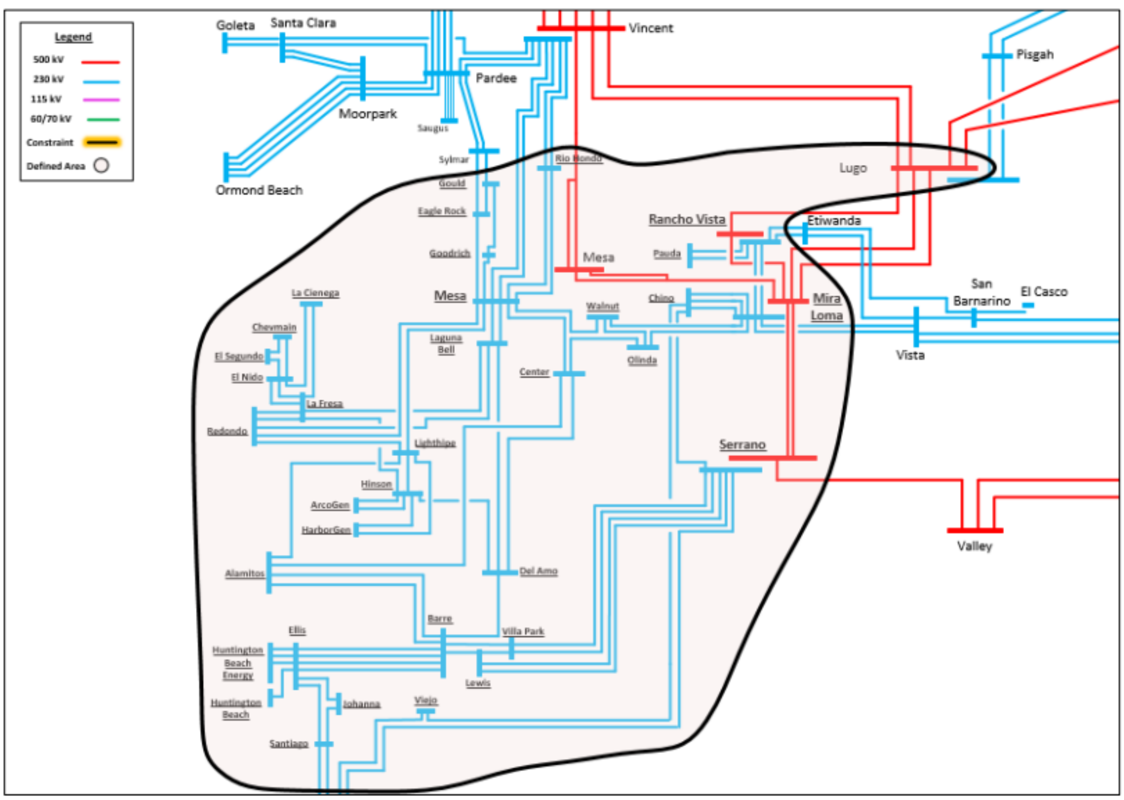
The assignment algorithm can be broken down into several key processes:

1. Assignment of substations to CAISO transmission constraints
2. Aggregation of substations into transmission clusters
3. Assignment of resource potential to substations

By mapping substations to transmission clusters, and resource potentials to substations, a unique build asset is created for every combination of technology and transmission cluster. The build assets are then used for RESOLVE modeling.

An example of a transmission constraint diagram from the CAISO transmission capability data is provided in Figure 13 below. Each transmission constraint consists of one or several substations among which transmission capability is limited.

*Figure 13. CAISO constraint boundary diagram outlining the SCE Metro Area Default Constraint*




Information from the CAISO deliverability constraint boundary diagrams and PG&E constraint boundary substation list is tabulated into a matrix relating substations to their memberships in the CAISO transmission constraints. In total, 106 constraints were included by CAISO in the

2023 whitepaper, and 450 substations with tie-in voltages of 115 kV or higher were included in those constraints. Information from the PG&E substation list was assumed to supersede the boundary diagrams. In consultation with CAISO, some modifications to CAISO's data were made to reflect additional info and to simplify some constraints within the model:

Once the substation-constraint membership matrix is created, it is used to identify the transmission clusters. A transmission cluster is a collection of substations that have identical memberships in transmission constraints. The 450 substations in the matrix were aggregated into 181 unique transmission clusters, with each substation assigned to a single cluster.

To create the build assets for RESOLVE, the available resource potentials (Sections 5.2 and 5.3) must be assigned to individual substations. Candidate gas-fired thermal resources (Section 5.1) and emerging technologies (Section 5.7) were excluded from the transmission analysis since the resource potentials of those technologies do not have a geospatial dependency.

The assignment of resource potentials to substations was done over the individual candidate project areas using a nearest-neighbor algorithm via geospatial analysis. Candidate solar, in-state (CAISO-interconnecting) wind and geothermal, pumped hydro, and compressed air energy storage resources were all assigned to substations in this way. Additionally, special assignments were made for the following technologies and resources:

- A portion of Greater Imperial Geothermal was redirected from the Imperial Valley substation to the Mirage substation, reflecting ongoing transmission projects around the Salton Sea.
- Out-of-state wind and geothermal resources are modeled as interconnecting to the CAISO system at the following substations (see Figure 14):

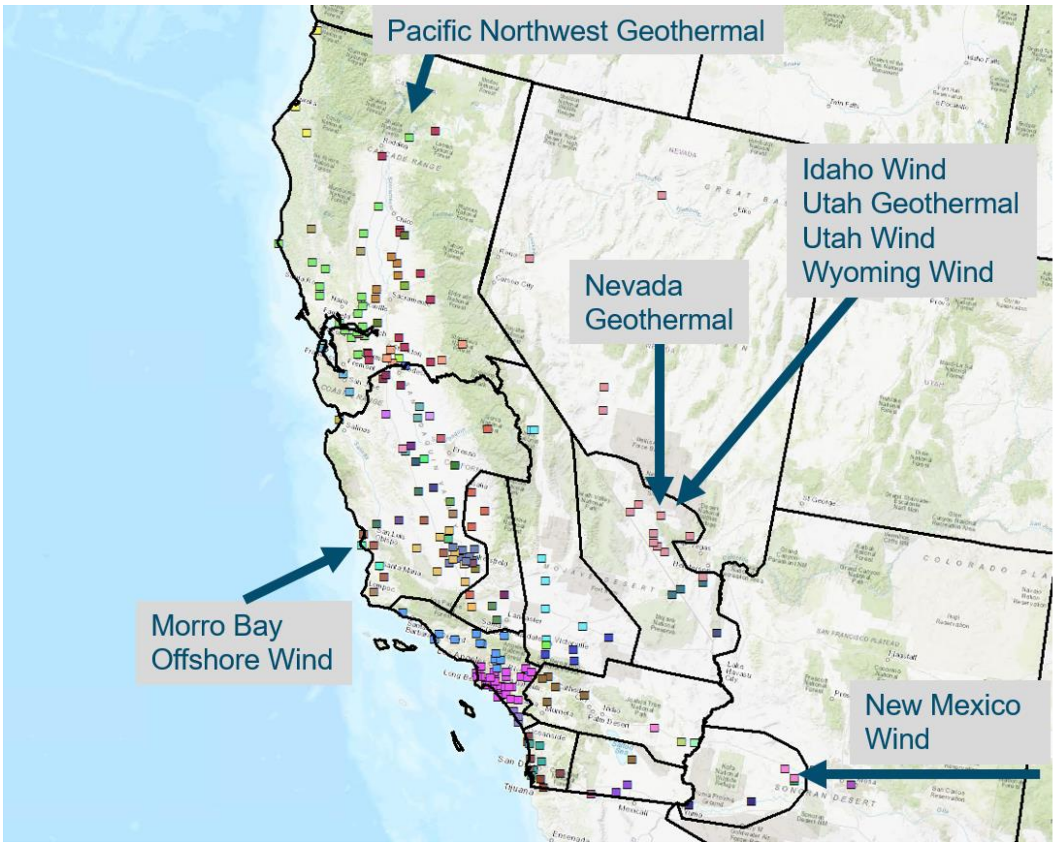
*Table 63. Substation assignments for resources in other states*

| State / Region | Substation |
|---|---|
| Central/Northern Nevada | Eldorado |
| Wyoming | Eldorado |
| Utah | Eldorado |
| Idaho | Eldorado |
| New Mexico | Palo Verde |
| Pacific Northwest | Round Mountain |
| Baja California | East County |

- Morro Bay Offshore Wind is assumed to interconnect to the Diablo Canyon substation.

- Other offshore wind resources are assumed to interconnect directly to load pockets in the Bay Area and are excluded from the CAISO transmission constraints.
- Three generalized biomass resources (Northern California, Central Valley North Los Banos, and Greater Imperial) were created and assigned to corresponding transmission clusters.

*Figure 14. Assumed tie-in locations for candidate resources requiring new transmission. Substations color-coded by transmission cluster. Specific upgrades needed for out-of-state and offshore wind resources discussed in Sections 5.5.4 and 5.5.5.*




Additionally, for every solar build asset, analogous build assets were created to represent 4-hour Li-ion battery, 8-hour Li-ion battery, and flow battery build assets. In this way, RESOLVE can always choose to pair a solar build with battery storage, if it is economical to do so. Battery storage creates slack in the Offpeak constraints (batteries are assumed to charge off peak) and is thus important to include at the same level of granularity as candidate renewable resources. Each battery storage build asset is assumed to have unlimited resource potential.

RESOLVE chooses to individually build assets using parameters that are specified for each build asset, including the available resource potential (Section 5.2.1), first available year and annual build limits (5.2.2), levelized build cost (5.2.3, 5.3), minimum build constraints (5.4), and transmission constraints. To reduce computational complexity, all build assets within the same resource region share the same production profile and hourly dispatch variables. Within

RESOLVE, the build assets are related to **dispatch resources** via custom constraints. The build assets carry all the resource potential and cost information, while the dispatch resources only contain operations data. For solar, onshore wind, offshore wind, and geothermal resources, the dispatch resources correspond to the RESOLVE regions introduced in Section 5.2.1 (Figure 5). Biomass build assets are mapped to the InState_Biomass candidate resource. All candidate storage build assets (4-hr Li-ion battery, 8-hr Li-ion battery, flow battery, pumped hydro, A-CAES) are assigned to singular dispatch resources representing each technology. This reduces the number of candidate storage resources that RESOLVE must optimize when simulating dispatch to five.

Complete results of the clustering analysis, including the substation-to-transmission cluster mappings, assignment of clusters to resource regions, and complete constraint memberships for all candidate resources, are provided in supporting documentation. The aggregated resources are incorporated into the CPUC IRP Resource Cost and Build workbook, and shapefiles are provided as supporting information.

### 5.5.3 Transmission Constraint Data

The amount of new capacity that can be accommodated on each transmission constraint is specified in the 2023 CAISO Transmission Capability Estimates whitepaper.[96] This table includes a listing of transmission constraint names, estimated system capability amounts in MW (existing and incremental), cost of upgrades necessary to accommodate incremental resources, and time to complete the upgrades for each constraint. Transmission upgrades that have already been approved by CAISO are represented as having zero upgrade cost in RESOLVE.

While CAISO has included many possible transmission upgrades in their whitepaper, the long-term transmission needs of a highly decarbonized CAISO energy system are not fully known. For the 2022-2023 IRP cycle, seven "Generic Transmission Upgrades" are modeled in RESOLVE. Generic transmission upgrades are included starting in the late 2030s to allow RESOLVE to choose resources in excess of the transmission capability and upgrades defined by CAISO. The generic upgrades are meant to represent reinforcements of the main transmission corridors in CAISO. The cost of each generic upgrade was determined by identifying the major archetypal transmission upgrades in the corresponding CAISO study area from the transmission capability estimates whitepaper, and averaging the costs of those upgrades. The Generic Transmission

[96] https://www.caiso.com/Documents/White-Paper-2023-Transmission-Capability-Estimates-for-use-in-the-CPUCs-Resrouce-Planning-Process.pdf.

Upgrades are first available in 2037 and 500 MW per year of transmission upgrade potential is added on each of the seven generic upgrades in every year starting in 2037.

Detailed transmission constraint data are provided in the accompanying RESOLVE User Interface workbook.

### 5.5.4 Out-of-State Transmission Cost

New out-of-state resources delivered to the CAISO system are attributed an additional transmission cost to deliver the resource to the CAISO system boundary, representing either the cost to wheel power across adjacent utilities' electric systems (for resources delivered on existing transmission or already developed transmission lines) or the cost of developing a new transmission line (for resources delivered on new transmission). Wheeling costs on the existing system are derived from utilities' Open Access Transmission Tariffs; the costs of new transmission lines are based on assumptions from publicly available transmission development costs or from information developed for the CEC's Renewable Energy Transmission Initiative 2.0 (RETI 2.0).[97] These costs only apply to resources that are modeled as out-of-state and outside of the CAISO system.

*Table 64. Transmission costs for out-of-state resources (before 2035), 2022 $/kW-yr*

| Resource Name | Tx Upgrade Costs | Wheeling Charge | Total Delivery Cost to CAISO Border | Remarks |
|---|---|---|---|---|
| Idaho_Wind | $60.61 | - | $60.61 | SWIP-North[98] |
| Utah_Wind | $58.70 | - | $58.70 | TransWest (Southern Half)[92] |
| Wyoming_Wind | $118.80 | - | $118.80 | TransWest[92] |
| New_Mexico_Wind | $71.20 | $30.78 | $101.98 | SunZia[99] + SRP Wheeling[100] |
| Pacific_Northwest_Geothermal | - | $33.19 | $33.19 | BPA Wheeling[101] |
| Central_Nevada_Geothermal | $61.36 | - | $48.08 | Greenlink[102] |
| Northern_Nevada_Geothermal | $61.36 | - | $48.08 | Greenlink[96] |

[97] https://www.energy.ca.gov/reti/
[98] CAISO 2021-22 TPP
[99] https://nmfwri.org/wp-content/uploads/2022/02/Mountainair-Collaborative_SunZia-Update-1-27-2022.pdf.
[100] http://www.oasis.oati.com/woa/docs/SRP/SRPdocs/SRP_OATT_08-01-2022_Final.pdf.
[101] https://www.bpa.gov/-/media/Aep/rates-tariff/current-transmission-rates/2022-transmission-rates-summary.pdf.
[102] https://lands.nv.gov/uploads/meeting_minutes/E2021-098.pdf.

| | | | | |
|---|---|---|---|---|
| Utah_Geothermal | $58.70 | - | $58.70 | TransWest (Southern Half)[92] |

*Table 65. Transmission costs for out-of-state resources (after 2035), 2022 $/kW-yr*

| Resource Name | Tx Upgrade Costs | Wheeling Charge | Total Delivery Cost to CAISO Border | Remarks |
|---|---|---|---|---|
| Idaho_Wind | $103.32 | $30.67 | $133.99 | SWIP-North[92] + New One Nevada (ON) Line[103] + UT Wheeling (PacifiCorp)[104] |
| Wyoming_Wind | $119.41 | $30.67 | $150.08 | Cross-Tie[97] + New One Nevada (ON) Line[97] + UT Wheeling (PacifiCorp)[98] |

Resources that require new transmission to reach the CAISO system are assumed to be delivered to a specific CAISO substation (Section 5.5.2). Within the CAISO system each out-of-state resource must compete for CAISO transmission capacity with other candidate renewable resources located inside the CAISO system. The total cost to deliver out-of-state resources on new transmission to CAISO load centers is the cost shown in Table 64 (before 2035) and Table 65 (after 2035, if different), plus any additional cost to develop transmission in CAISO transmission constraint zones (Section 5.5.3) if the capacity of the existing CAISO transmission system is not sufficient.

### 5.5.5 Offshore Wind Transmission Cost

Offshore wind resources will require transmission upgrades to deliver FCDS capacity to the CAISO system. Assumptions for offshore wind transmission upgrades are adopted from the CAISO 2021-2022 Transmission Plan.[105] The size of the offshore wind transmission upgrades are assumed to be equivalent to the resource potential MW totals (Section 5.2.1.5).

The Morro Bay upgrade includes upgrades to the Morro Bay 500 kV substation; Morro Bay Offshore Wind is assumed to interconnect to the CAISO system at Diablo Canyon and is subject to additional CAISO transmission constraints. The transmission upgrade costs for the other offshore wind resources include the cost of underwater cabling to deliver the resources directly

[103] CAISO 20-Year Outlook.
[104] https://pscdocs.utah.gov/misc/22docs/2299901/323217RMPLmtdRvsnsOATTAttH1FERCER2215103-30-2022.pdf.
[105] http://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

to load centers in the San Francisco Bay Area; as such, these resources are not modeled on additional CAISO transmission constraints.

*Table 66. Transmission upgrade data for offshore wind resources*

| Resource Name | Tx Upgrade Costs (2022 $/kW) | Construction Lead Time (months) | First Available Year | Remarks |
|---|---|---|---|---|
| Morro_Bay_Offshore_Wind | $42.12 | 72 | 2032[(1)] | Morro Bay 500 kV Substation |
| Humboldt_Bay_Offshore_Wind | $1,602 | 120 | 2034 | Underwater cabling to Bay Area |
| Cape_Mendocino_Offshore_Wind | $2,000 | 180 | 2039 | Underwater cabling to Bay Area |
| Del_Norte_Offshore_Wind | $2,000 | 180 | 2039 | Underwater cabling to Bay Area |

*[(1)] Availability is limited by the resource potential (Section 5.2.1.5).*

## 5.6 Demand Response

### 5.6.1 Shed Demand Response

Shed (or "conventional") demand response reduces demand only during peak demand events. Assumptions on the cost, performance, and potential of candidate new shed demand response resources are based on Lawrence Berkeley National Laboratory's (LBNL) Phase 4 California Demand Response Potential Study for the CPUC.[106] The resource potential supply curve is based on data outputs from LBNL's DRPATH model, with the scenario assumptions outlined below in Table 67. DRPATH potential estimates are not incremental to existing demand response programs. Consequently, LSE demand response programs, including demand response procured through DRAM, are removed from the DRPATH supply curve because these programs are represented as baseline resources (see Section 3.5). On the assumption that lower cost DR has been the focus of LSE DR programs, DR potential is removed from the supply curve in order of least to most expensive. LBNL's supply curve includes pumping loads so the existing interruptible pumping load has also been removed from the lowest cost price tranches of the supply curve. LBNL models DR potential in 2025, 2030, 2040, and 2050. DR potential is linearly interpolated between years as needed. An alternative option, included as an option for sensitivity analysis, explores resource portfolio selection when all shed DR potential is available

[106] Lawrence Berkeley National Laboratory, *Overview of Phase 4 of the California Demand Response Potential Study* (2022). Available at: https://emp.lbl.gov/publications/overview-phase-4-california-demand

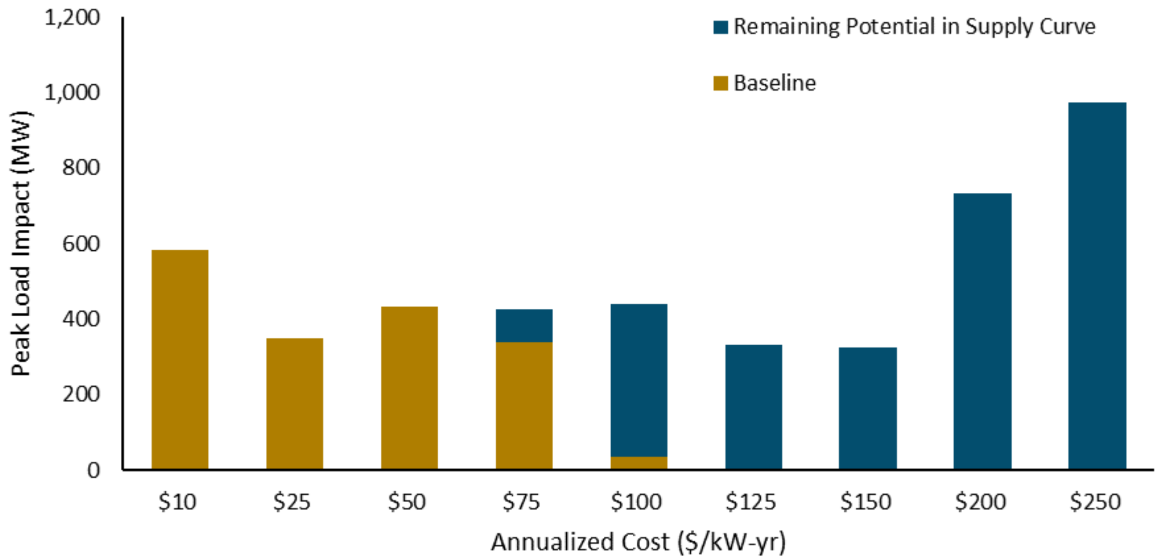
in all modeled years. Finally, the shed DR potential in the supply curve includes costs as high as $1,000 per kW-year; Figure 15 shows the supply curve through the $250 per kW-year tier.

In RESOLVE, DR candidate resources are modeled with a 10-year lifetime as an average estimate on life of service per LBNL inputs. The supply curve costs are modeled as fixed O&M costs representing the annualized cost of equipment and DR program participation costs needed to keep the resources available for load shedding.

*Table 67. Scenario assumptions for LBNL's DRPATH model used to generate shed DR supply curve data for IRP modeling.*

| Category | Assumption |
|---|---|
| IEPR CED Year | 2021 |
| DR Availability Scenario | Medium |
| Weather | 1 in 2 weather year |
| Energy Efficiency Scenario | Mid AAEE (Scenario 3) |
| Fuel Substitution Scenario | Mid AAFS (Scenario 3) |
| Rate Scenario | Rate Mix 1—TOU and CPP (as defined by LBNL report) |
| Cost Framework | Gross |

*Figure 15. Conventional demand response supply curve in 2035*



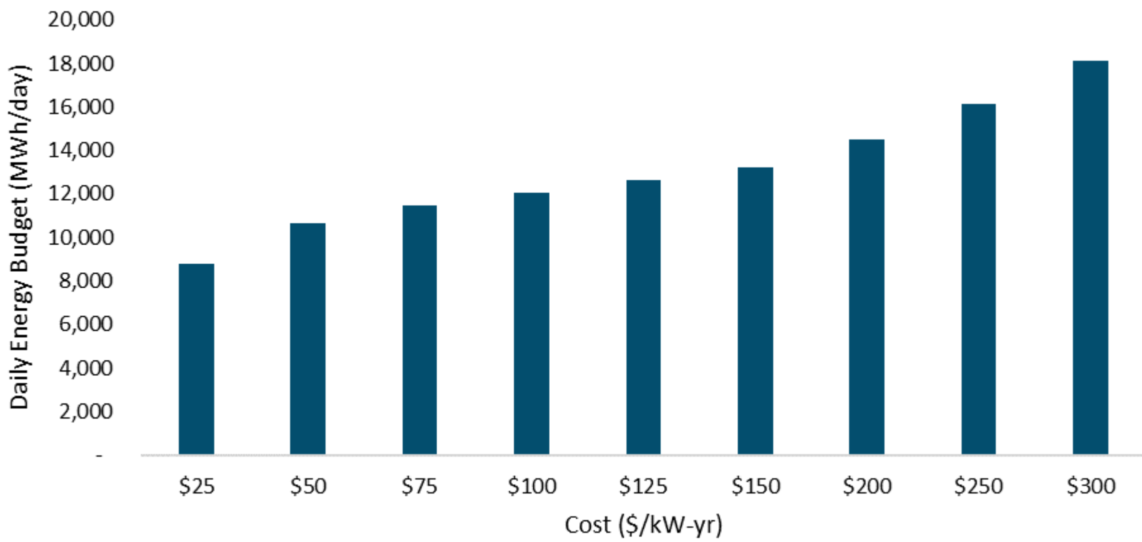

### 5.6.2 Shift Demand Response

"Shift" demand response (also called "flexible load") in RESOLVE is an energy-neutral resource that can move demand within a day, subject to hourly and daily constraints on the amount of energy that can be shifted. End-use energy consumption in RESOLVE can be shifted, for example, from on-peak hours to off-peak hours; the maximum amount of energy shifted in one day is the daily energy budget. The quantity of shift demand response is reported in units of (MWh/day)-yr, which is the average available *daily* energy budget for a given year. It is currently assumed that the full daily energy budget is available on every day of the year. RESOLVE includes a constraint that sets a maximum quantity of energy that can be shifted in one hour. It is also assumed that there is no efficiency loss penalty incurred by shifting loads to other times of the day.

Assumptions on the cost, performance, and potential of candidate advanced demand response resources are based on Lawrence Berkeley National Laboratory's report for the Phase 4 California Demand Response Potential Study.[107] The resource potential supply curve is based on data outputs from LBNL's DRPATH model, with the same set of scenario assumptions used to create the Shed DR supply curve (see Table 67).

[107] Lawrence Berkeley National Laboratory, *Overview of Phase 4 of the California Demand Response Potential Study* (2022). Available at: https://emp.lbl.gov/publications/overview-phase-4-california-demand

*Figure 16. Shift demand response: total annual costs vs potential daily energy budget in 2035.*




The 2022-2023 IRP cycle does not include a scenario in which shift DR is available for selection as a candidate resource.

## 5.7 Emerging Low- and Zero-Carbon Technologies

### 5.7.1 Introduction

This section provides information on low- and zero-carbon technologies that could potentially support California's efforts to decarbonize its electricity grid but have not yet reached full commercialization. The data shown in the cost and efficiency figures shown in this section were first published in a CPUC Report in 2022,[108] which then served as the basis for material discussed in a CPUC Inputs and Assumptions Modeling Advisory Group (MAG) meeting.[109]

The section details low- or zero-carbon firm capacity generation and storage technologies, and negative carbon emissions technologies (NETs). Firm capacity technologies are those that can be dispatched during peak grid demand periods without binding restrictions on the duration for which power can be provided. These technologies may facilitate cost-effective achievement of electric decarbonization by providing firm capacity during extended periods of low wind and solar output, depending on the assumptions used. NETs are technologies that can help remove $CO_2$ from the atmosphere.

[108] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

[109] CPUC IRP Inputs and Assumptions Document Meeting, 9/22/2022.

However, these technologies are nascent or potentially geographically limited (in the case of gravity storage, compressed-air energy storage, and potentially carbon capture), and it is uncertain if they can reach maturity and hit the longevity, cost, and efficiency targets projected by industry. Thus, for the foreseeable future these resources are likely only to be considered in sensitivity-type analysis in IRP, and not for core portfolios sis that are considered for adoption in the IRP proceeding.

## 5.7.2 Storage and Generation Technology Overview

### *5.5.2.1 Introduction*

This section details the following technologies, and provides a high-level of each technology, its characteristics, advantages and disadvantages:

+ Long-duration energy storage (LDES).
+ Carbon-free hydrogen that can be generated with renewable electricity.
+ Stationary Fuel Cells and Hydrogen Combustion Turbines.
+ Combined cycle and combustion turbine plants respectively retrofitted with post-combustion carbon capture and sequestration (CCS) and oxyfuel-based CCS.
+ Enhanced geothermal systems (EGS).
+ Small modular light water nuclear reactors (SMRs).

### *5.5.2.2 Long-duration energy storage*

This section discusses emerging long-duration energy storage technologies. IRP also models pumped hydro storage, which is a conventional long-duration energy storage technology (Section 5.3.1).

LDES can take various forms. This document details generic LDES, but various forms, such as electrochemical, thermal-, pressure-, and gravity-based storage exist. Electrochemical LDES couples reduction and oxidation chemical reactions to store energy. This technology class operates similarly to a Li-Ion battery, but employ different materials with lower costs and lower round-trip efficiency than an Li-Ion battery. Thermal energy storage stores electricity in the form of latent and/or sensible heat, and then that is converted back into electricity upon discharging via typical thermal power cycles or via semiconductor technologies. Gravity-based storage moves objects such as water or heavy objects upwards relative to the earth’s gravity to store energy, then discharges by letting those objects return downwards while turning electricity generators.

The primary advantage of long-duration storage relative to other energy storage technologies is that this technology class exhibits lower energy storage ($/kWh) capital costs than Li-Ion batteries, as well as higher round trip efficiencies than electrofuel synthesis-based energy storage. Furthermore, electrochemical or thermal-based systems would be able to be located at convenient grid interconnection points rather than requiring geological formations suitable for underground storage, as is necessary for A-CAES and electrofuels. The primary disadvantage of long-duration storage is that they often exhibit lower round-trip efficiency than Li-Ion batteries, and may not achieve the cost and efficiency targets projected by industry due to limited applications for these LDES technologies, compared to other technologies that may benefit from cross-sectoral applications or industrial scaling.

#### *5.5.2.4 Electrofuels and Energy Reconversion Technologies*

Electrofuels are a class of fuels generated using electricity, water, and in some cases $CO_2$ to generate fuel. This document provides data for hydrogen, which is a subclass of electrofuels. This document details costs for low-temperature electrolysis technologies (e.g., alkaline electrolyzers), which use electricity and water as inputs to produce gaseous hydrogen and oxygen. Hydrogen can be pressurized and stored underground in geologic formations or in tanks, and can be reconverted to electricity using combustion in a purpose-built combustion turbine, or converted to electricity using a stationary fuel cell (for hydrogen).

The primary advantage of electrofuels is that they can be stored at low energy cost ($/kWh) enabling very long-duration storage. The disadvantages of electrofuels are their low round-trip efficiency, the need for specific geologic formations to enable low-cost storage, and the need to build new gas storage and gas pipeline infrastructure for hydrogen.

RESOLVE will co-optimize a least-cost electrofuel production and consumption system which utilizes zero-carbon electricity to power alkaline electrolyzers, underground or tank-based fuel storage for storing produced hydrogen, combined-cycle or combustion turbines for converting the produced hydrogen back to electricity, and optionally a fixed-size pipeline for transporting hydrogen from one region to another.

#### *5.5.2.5 Hydrogen Combustion Turbines*

Hydrogen combustion turbines combine oxygen from air and hydrogen to produce electricity. Stationary hydrogen fuel cells do so without using combustion, whereas hydrogen combustion turbines combust hydrogen in the same manner as natural gas power plants. The advantages of combustion turbines are there are small cost differences between natural gas and hydrogen turbines, and there may be opportunities to retrofit some existing natural gas power plants to run on hydrogen. The disadvantages are that hydrogen combustion turbines produce $NO_x$ and other criteria pollutants, and they have not yet been deployed commercially burning pure hydrogen.

#### *5.5.2.6 Combined Cycle Power Plants with Carbon Capture and Allam Cycle Power Plants*

These two technologies involve natural gas combustion with carbon capture and sequestration (CCS). Combined Cycle Power Plants with post-combustion capture use a CCS system as an addition to a conventional CCGT. Allam cycle power plants separate oxygen from air, and burn natural gas in a mixture of oxygen, water vapor and recycled $CO_2$. $CO_2$ can then be captured from the exhaust in an already pressurized, concentrated state. The advantages of CCGTs with post-combustion capture is the technology is more mature than Allam cycle plants, and the technology may be retrofit to certain types of existing natural gas plants. The costs in this document represent the cost of new CCGTs with CCS. The disadvantage is such plants are less efficient than Allam cycle plants, do not enable 100% CCS, and do emit $NO_x$ and other criteria pollutants. Allam cycle plants offer higher efficiency, should exhibit emit little or no criteria pollutants, and enable 100% carbon capture. The disadvantages are that this is a lower maturity, higher cost technology, and requires oxygen separation units. Both rely on constructing an extensive network of CCS pipelines and wells, and neither technology would mitigate upstream emissions and other impacts from extracting and transporting natural gas.

RESOLVE will include options for 90% CCS retrofits of existing CCGT units, new candidate 95% CCS units, and 100% Allam cycle units for selection. The capacity of 90% CCS retrofits selected in the model will correspond with a reduction in the capacity of CAISO CCGTs from the resource baseline.

#### *5.5.2.7 Enhanced Geothermal Systems*

Enhanced geothermal systems (EGS) are analogous to conventional geothermal (Section 5.2.1), but rely on accessing heat from deeper underground than conventional systems using advanced well drilling and subsurface permeability enhancement technology. The advantages of such systems are that the technical power generation potential and locations in which one could install geothermal power plants increase through the use of novel well drilling techniques. The primary disadvantages are that these systems are technologically immature, have highly uncertain future costs, and have potentially higher costs than other zero-carbon generation resources. The data presented in this document are based on near-field EGS.

#### *5.5.2.8 Small Modular Nuclear Reactors*

Small modular nuclear reactors are a class of nuclear power plants that use smaller scale reactors that can in theory have standardized design, be produced at higher volumes than conventional light-water reactors in factories and be deployed in arrays. This is analogous to combustion turbines that can be aggregated into combined cycle natural gas power plants. While there are many potential nuclear power cycles that could be deployed in this fashion, this document focuses on conventional light-water reactors. The primary advantage of such technologies is there may be significant cost and construction lead time reductions enabled by standardization and higher production rates. The disadvantages are that the technology has an uncertain pathway to cost reductions, would produce nuclear waste, and that new nuclear plants cannot be built in California under current law. To consider new SMR capacity additions in IRP, they would have to build units out of state and be paired with firm transmission into CAISO.

### 5.7.3 Cost and Efficiency Data

#### *Cost and Efficiency Plots*

The figures below present illustrative cost projections for the technologies listed above. Figure 17 shows illustrative capital cost and levelized fixed cost data ranges for storage and generation technologies. The assumptions for how these data were derived are shown in Table 68. Additionally, the levelized fixed cost data shown in Figure 18 and Figure 19 have levelized IRA ITCs, but do not include any PTC value. PTCs are volumetric tax credits, and thus will only be relevant once RESOLVE determines their capacity factors.

Under current IRS guidelines, an energy project can select to receive either an ITC or a PTC for all eligible project components—not both. Tax credits can stack, but a single financial entity can only receive one type of tax credit. Under the IRA, carbon capture and sequestration (CCS), direct-air-capture (DAC) methane, and hydrogen are unique technologies that have special PTC carve-outs for carbon sequestration and hydrogen production. Depending on the actual financing structure used in the future, it may be possible for certain components of these technologies, such as the DAC or hydrogen electrolyzer, to be sourced or financed separately and receive the PTC while the combustion turbine receives an ITC. Thus, PTCs may reduce the levelized cost of CCS and hydrogen below these reported values.

*Table 68: Data sources and assumptions for emerging technology costs*

| Technology | Low-Cost Trajectory Assumptions | High-Cost Trajectory Assumptions | Cost Estimate Certainty |
|---|---|---|---|
| Generic Energy Storage (24-hr) | PNNL Cost and Performance Database[110]; HydroStor[111]<br><br>24-hour Storage | Same data sources as low-cost, assume 0% learning rate | Low |
| Generic Energy Storage (100-hr) | McKinsey / Long Duration Energy Storage Council[112]<br><br>100-hour Storage | Same sources as low-cost, assume 0% learning rate | Low |
| Hydrogen | CEC 2021[113]; NREL H2A[114]; utility IRP filings,[115] Lord et al[116], Ahluwalia et al[117], ANL[118], Hunter et al[119]<br><br>Electrolyzer<br>240-hr Salt cavern storage<br>ITC-eligible Aero-CT (new build) | Same data sources as low-cost, assume 0% learning rate for PEM systems. | Medium |
| Allam Cycle CCS | NREL 2023 ATB[120], Allam et al.[121], 8 Rivers Capital[122] | Same data sources as low-cost. | Low-Medium |
| EGS, Nuclear SMR, CCGT + 95% CCS, 90% CCS Retrofits | NREL 2023 ATB | NREL 2023 ATB | Low (EGS), Medium (Nuclear SMR, CCGT + CCS) |

[110] Pacific Northwest National Laboratory. 2020. Compressed Air Energy Storage (CAES). https://www.pnnl.gov/compressed-air-energy-storage-caes

[111] Hydrostor. 2022. "FAQ – Hydrostor." https://www.hydrostor.ca/faq/ Accessed 07/26/2022.

[112] Alberto Bettoli, Martin Linder, Tomas Nauclér, Jesse Noffsinger, Suvojoy Sengupta, Humayun Tai, and Godart van Gendt. McKinsey Electric Power & Natural Gas Sustainability Practices. "Net-zero power: Long-duration energy storage for a renewable grid." 2021. https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid

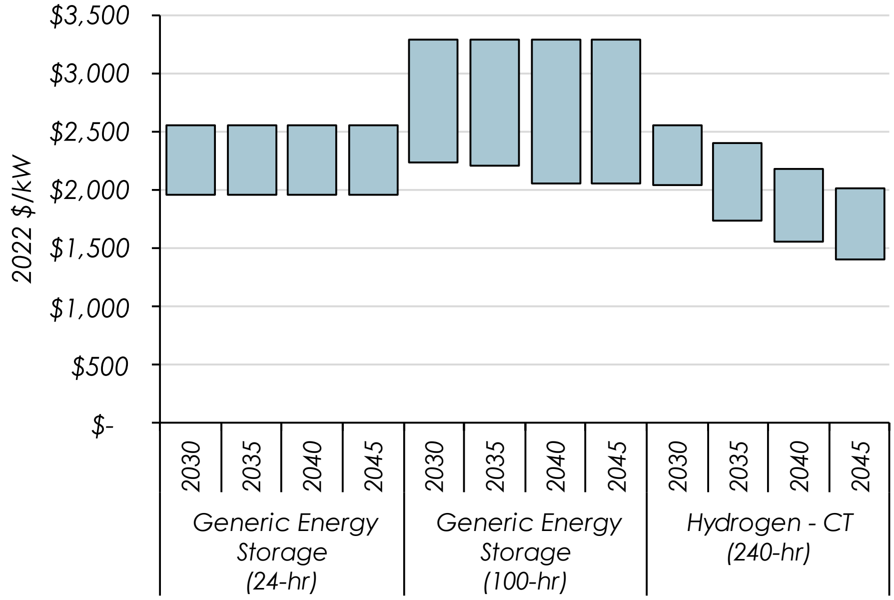
[113] California Energy Commission. The Challenge of Retail Gas in California's Low-Carbon Future. 2021. https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf.

[114] National Renewable Energy Laboratory. H2A: Hydrogen Analysis Production Model Archives: Future Central Hydrogen Production from Natural Gas with $CO_2$ Sequestration version 3.101. https://www.nrel.gov/hydrogen/assets/docs/future-central-natural-gas-with-co2-sequestration-v3-101.xlsm.

[115] Public Service of New Mexico. 2020. 2020 Integrated Resource Plan. https://www.pnmforwardtogether.com/irp.

[116] Lord, A., Kobos, P., Borns, D. "Geologic Storage of hydrogen: Scaling up to meet city transportation demands." *International Journal of Hydrogen Energy*. 39 (2014): 15570-15582. https://doi.org/10.1016/j.ijhydene.2014.07.121.

Figure 17. Capital costs of emerging zero-carbon firm capacity storage technologies




Finally, this document assumes that the high bounds of capital cost data for 24-hr generic energy storage and 100-hour generic energy storage do not decline. This assumption is made because there is high uncertainty in these technologies' costs, rather than a certainty that there will be no cost reductions.

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117 Ahluwalia et al. 2019. System Level Analysis of Hydrogen Storage Options. https://www.hydrogen.energy.gov/pdfs/review19/st001_ahluwalia_2019_o.pdf

118 Argonne National Laboratory. Hydrogen Delivery Scenario Analysis Model. https://hdsam.es.anl.gov/index.php.

119 Hunter, C., Penev, M., Reznicek, E., Eichman, J., Rustagi, N., Baldwin, S. Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids. *Joule*. 2021. https://doi.org/10.1016/j.joule.2021.06.018

120 National Renewable Energy Laboratory. 2023 Electricity ATB Technologies. https://atb.nrel.gov/electricity/2023/technologies

121 Allam et al. Energy Procedia. 2017. Demonstration of the Allam Cycle: An update on the development status of a high efficiency supercritical carbon dioxide power process employing full carbon capture. https://doi.org/10.1016/j.egypro.2017.03.1731.

122 "8 Rivers Capital, ADM Announce Intention to Make Illinois Home to Game-Changing Zero Emissions Project.". 2021. https://www.prnewswire.com/news-releases/8-rivers-capital-adm-announce-intention-to-make-illinois-home-to-game-changing-zero-emissions-project-301269296.html.

*Figure 18. Capital Costs of emerging low- and zero-carbon firm capacity generation technologies*

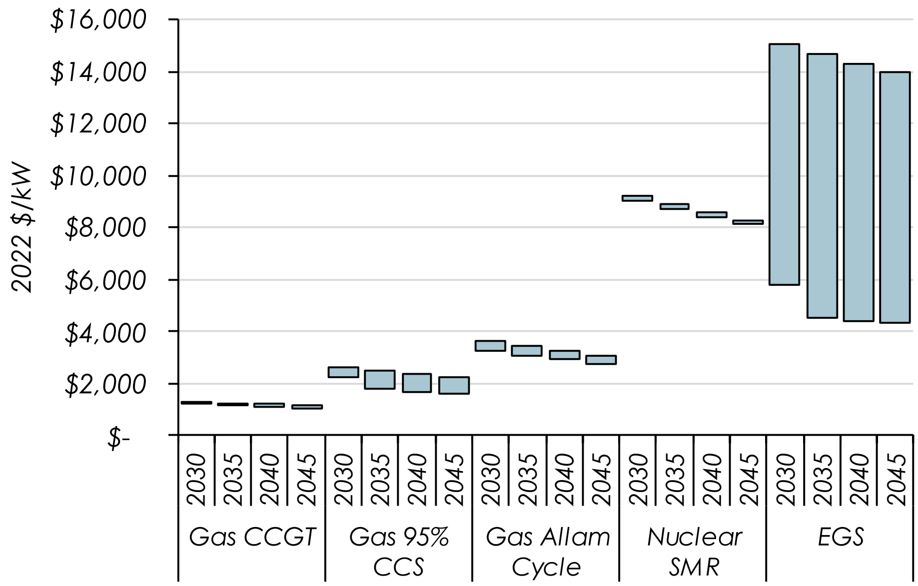



*Figure 19. Levelized fixed costs of emerging zero-carbon firm capacity energy storage technologies*

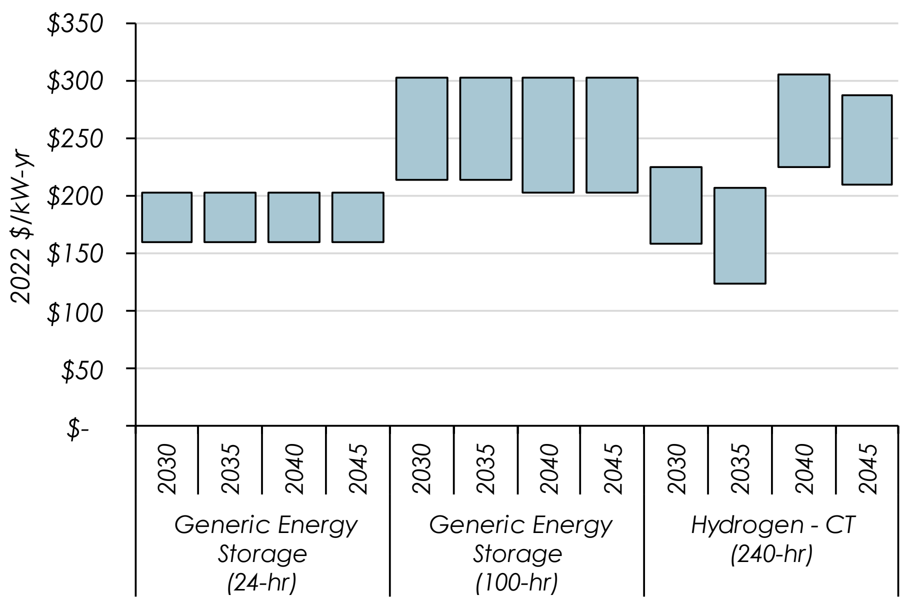
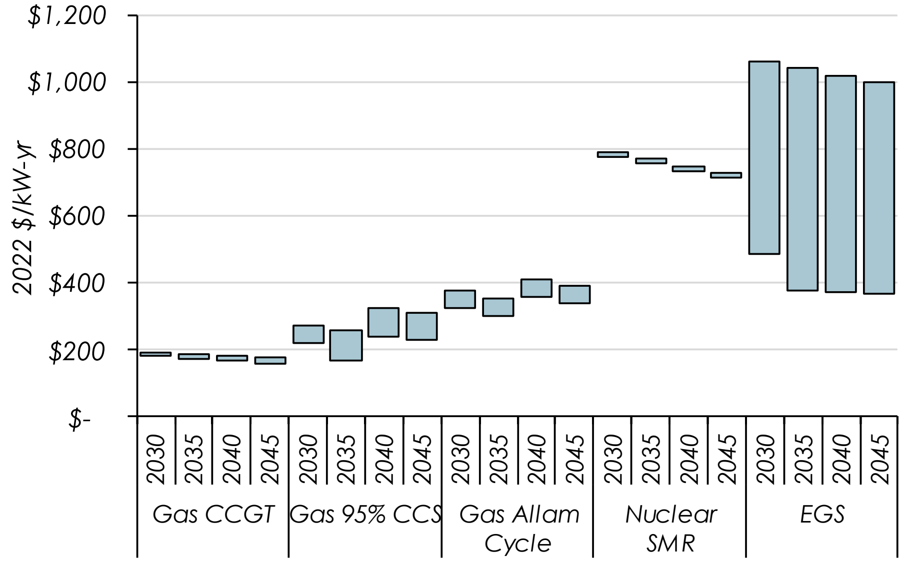


*Figure 20. Levelized fixed costs of emerging low- and zero-carbon firm capacity generation technologies*




Generally, analysis shows there are large uncertainty bounds for many technologies, especially EGS. While the levelized fixed cost of energy storage technologies can provide useful information on what technology is least cost per kW, longer duration technologies will exhibit higher capacity values in deeply renewable grids and thus direct comparison between the technologies' levelized fixed cost can be misleading. Finally, this document shows that natural gas-based technologies could have low levelized fixed costs relative to other generation technologies, however the plots omit the fuel cost to run these plants.

### 5.7.4 Negative Emissions Technologies

E3 has provided data below for direct air capture (DAC), which is a class of NET that consumes electricity remove $CO_2$ from atmospheric air. The technology works by using fans to force atmospheric air over $CO_2$ absorbing chemicals (either liquid solvents or solid sorbents). These chemicals are then heated and, in some cases, depressurized to release concentrated $CO_2$ and regenerate the chemicals so they can absorb more $CO_2$. Concentrated $CO_2$ can then be sequestered via CCS.

Given the limited data available and variations in potential chemical processes, this document assumes that DAC will be powered by off-grid renewables and will be modeled as a $/tCO2 removed per year. DAC would be eligible for enhanced 45Q tax credits under the IRA. Given limited data on DAC data, assumptions are presented as a range between conservative and optimistic, with no assumed learning associated with cost declines between 2030 and 2045.

*Table 69. Technoeconomic Data for Emerging Negative Emissions Technologies*

| Data | Value Range |
| --- | --- |
| **Efficiency (kJ/kg $CO_2$ captured)** | 800 - 1,790 |
| 2030 Capex Cost **(2022 \$/t$CO_2$ removed per year)** | 89 - 256 |
| 2045 Capex Cost **(2022 \$/t$CO_2$ removed per year)** | 89 - 256 |

*Source: NAS[123]*

## 5.8 Vehicle Grid Integration (VGI)

According to D.20-12-029[124], Vehicle-Grid Integration (VGI) refers to "any method of altering the time, charging level, or location at which grid-connected electric vehicles charge or discharge, in a manner that optimizes plug-in electric vehicle interaction with the electrical grid and provides net benefits to ratepayers." For the purpose of this IRP cycle, VGI is categorized as two main types:

1. VGI included in the IEPR forecast in response to Time-Of-Use (TOU) rates.
2. VGI beyond the IEPR forecast in response to dynamic grid signals and capable of discharging back to the grid (V2G).

The former represents strategies that can be implemented with TOU rates to shift load (V1G), whereas the latter can be actively managed by third-party aggregators or incentivized by dynamic price signals to shift load (V1G) beyond TOU rates or discharge back to the grid (V2G).

V1G in response to TOU rates has already been included in IRP because the IEPR load shapes for light, medium and heavy-duty vehicles used in IRP assume some level of TOU rate responsiveness.

In the 2022-2023 IRP cycle, VGI in response to dynamic grid signals is available to estimate the savings from further management of EV charging load beyond TOU rates. For this IRP cycle, VGI added in response to dynamic grid signals will focus on only light duty vehicles (LDV), as LDV are projected to consist of the majority (82%) of transportation load in 2035 (see Table 2). Scope

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123 National Academies of Sciences, Engineering, and Medicine. 2010. Negative Emissions Technologies and Reliable Sequestration. https://www.nap.edu/catalog/25259/negative-emissions-technologies-and-reliable-sequestration-a-research-agenda

124 Decision 20-12-029. DECISION CONCERNING IMPLEMENTATION OF SENATE BILL 676 AND VEHICLE- GRID INTEGRATION STRATEGIES:

https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M355/K794/355794454.PDF for medium and heavy-duty vehicles will potentially be included in future cycles. VGI is only modeled at residential and workplace locations as vehicles parked at these locations have long enough charging times and relatively predictable charging behaviors for load shifting. Charging at public locations, especially fast charging, usually takes less time, leaving minimal potential to shift load. Newly-added VGI resources are modeled as statewide aggregated resources with four types:

*Table 70. Definition of VGI Resource Types*

| Resource Types | Definition |
|---|---|
| V1G Residential<br>V1G Workplace | Shifting EV charging load beyond TOU rates |
| V2G Residential<br>V2G Workplace | Shifting EV charging load beyond TOU rates +<br>Capable of discharging back to the grid |

The study is designed to model VGI in response to dynamic grid signals in a framework similar to a supply-side resource with assumptions in costs in $/kW-yr and potential (MW). This modeling approach is chosen because RESOLVE is a capacity expansion model that cannot directly model retail rates as compensations to resources. This modeling approach does not indicate any CPUC endorsed program design for VGI. The objective of this study is to quantify the value of various V1G and V2G actions in the context of system planning and the impact of VGI on resource portfolio.

To model VGI in response to dynamic grid signals, information on when the vehicles are plugged in is needed to estimate how much load can be shifted beyond TOU rates. Charging behaviors will first be simulated in E3's EV Load Shape Tool (EVLST) to mimic the latest IEPR load shapes and generate corresponding flexibility parameters with the assumption of around 80% responsiveness to TOU rates. EVLST simulates and optimizes charging behaviors from drivers' perspective to meet driving needs and minimize energy bills. These flexibility parameters will then be used as inputs into RESOLVE to optimize the dispatch of VGI resources in RESOLVE to meet grid needs. The flexibility parameters include windows when charging behaviors can be shifted, the amount of energy that can be shifted in a day, and hourly potential to further increase or decrease EV charging load compared to the TOU baseline.

### 5.8.1 Resource Potential

VGI resource potential for LDV is developed by estimating the percentage of vehicles with access to residential or workplace Level 2 (L2) chargers and are willing to enroll in VGI programs that involve active management in response to grid signals. The V1G potential is estimated based on the percentage of drivers have access to L2 chargers at residential and workplace and using enrollment curves provided by LBNL from the draft report of the California Demand Response (DR) Potential Study, Phase 4. It is assumed that around 40% of total drivers have access to L2 chargers at home and around 30% of total drivers have access to L2 chargers at the workplace.[125]

Two scenarios, a Mid Enrollment and High Enrollment scenario in residential enrollment curves, will be developed to estimate the low and high bookends of the VGI potential (both V1G and V2G) in the residential sector. Since the enrollment curves were developed based on general DR programs that do not fully reflect VGI-specific enrollment, the original residential enrollment curve provided by LBNL was adjusted for both scenarios with a starting point of the VGI enrollment in the residential sector at around 21%, based on the participation of EV-TOU rates in California in 2021.[126] The reasoning is that VGI programs are less interruptive to customers than DR programs since they are mostly designed not to interrupt drivers' driving needs and change driving behaviors, thus resulting in higher enrollment potential. By the end of 2021, around 21% of EV customers are enrolled in EV-TOU rates without any incentive.[127] These customers are assumed to be willing to participate in VGI programs, if available, with minimal incentive.

The difference of the Mid Enrollment and High Enrollment scenario comes from how much incremental potential could be induced by higher incentives ($/kW-yr).

- **Mid Enrollment scenario**: shifts the original LBNL enrollment curve vertically by increasing the enrollment potential by 21% at all incentive levels. It results in a relatively low incremental increase in VGI potential at low-cost range. This is consistent with an

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[125] Access to charging is estimated based on a combination of sources including US census data and NREL EVI-Pro2 Input Presentation (https://www.nrel.gov/docs/fy21osti/77651.pdf).

[126] Joint IOU Electric Vehicle Load Research and Charging Infrastructure Cost Report 10th Report Filed on March 31, 2022: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/10th-joint-iou-ev-load-report-mar-2022.pdf.

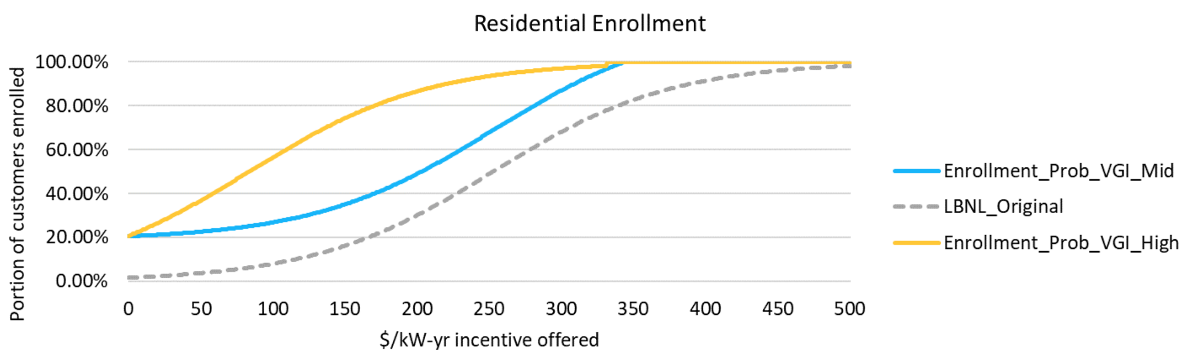
[127] Joint IOU Electric Vehicle Load Research and Charging Infrastructure Cost Report 10th Report Filed on March 31, 2022. Total number of customers on EV rates are calculated by adding the single meter and separately metered accounts in single family and multi-dwelling units in Chart PG&E-1, Chart PG&E-2, Chart SCE-1, Chart SCE-2a, Chart SDG&E-1, Table SDG&E-2A and Table SDG&E-3. The total number of accounts on EV rates is estimated to be around 151,385 and the total number of EVs in the IOU territories is about 735,348 as of December 2021, which is about 21%.

observation from LBNL that the fraction of the residential program participants within the low-cost range does not increase that much with higher incentives offered.

- **High Enrollment scenario**: shifts the original LBNL enrollment curve horizontally by assuming that VGI enrollment has reached the potential around 21% at $0/kW-yr and could be scaled relatively faster with higher incentives. This is consistent with an observation provided by a stakeholder that their driver propensity is around 98% at a cost range of $200-$400/kW-yr.

The two scenarios mentioned above will only change the assumptions for resource potential but do not change the incentive cost levels and other assumptions. The commercial sector will directly use the original LBNL enrollment curve given its reasonableness and smaller impact on statewide potential compared to the residential sector.

*Figure 21. VGI residential enrollment curve for the Mid Enrollment and the High Enrollment scenario*




V1G potential modeled for IRP comes from a cost range of $0-50/kW-yr of enrollment curves. Although enrollment curves developed based on existing DR programs may provide some prediction of V1G enrollment at different incentive levels, they are limited in their ability to reflect the enrollment of relatively nascent technologies like V2G and how future VGI policies may look like. Currently, V2G availability is still relatively low at the early stage of the market, and we anticipate that V2G customers expect higher compensation for exporting power than V1G customers expect from managing charging. To account for V2G's higher costs and low penetration at this stage, two major assumptions are made to estimate V2G enrollment:

- A flat cost adder of $50/kW-yr is added to the level of incentives assumed for V1G to reflect the higher payment expected by V2G customers to provide not only load shifting but also discharging services.[128]

- The V2G enrollment potential corresponding to the higher incentive costs is derived from the same function as V1G potential, but it is multiplied by a percentage (%) to reflect V2G potential as a portion of V1G potential at the same incentive level.

The current assumption is that V2G potential starts at 0% of V1G potential in 2025 and grows to 50% of V1G potential in 2050. The starting year of 2025 is set based on a lack of available programs and price signals to allow vehicle discharging in the near term and an estimated timeline when V2G could scale in California. Scaling V2G requires technology readiness, price signals, and policy framework (e.g., FERC Order 2222) in place. CAISO submitted its FERC Order 2222 compliance filling in 2022 and it is expected to take several years to fully implement the policy.[129] The 50% in 2050, an assumption looking decades into the future, is entirely for planning purposes; considering that not all OEMs are willing to enable vehicles to be V2G capable and warranty battery for grid use by 2050 and not all drivers will want to use their vehicles as a grid asset. However, sensitivity analysis with higher V2G penetration levels could be explored to inform a broader range of potential VGI outcomes.

The VGI potential is calculated as the following:

> VGI Potential by each incentive tranche (%) = % Access to L2 charger * % Enrollment by incentive tranche * % V2G as a percentage of V1G potential.

The percentage of V1G potential by each incentive tranche (Table 71) is derived from the enrollment curves and assumed to be constant throughout all years for a given incentive level. The percentage of V2G potential is modeled as growing each year as V2G as a percentage of V1G potential increases.

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[128] The cost adder of $50 is added to match the level of incentives paid to Demand Response (DR) Programs as V2G is very similar to DR: https://cpowerenergy.com/wp-content/uploads/2020/02/CA_Snapshot_january-2020-No-LCR.pdf.

[129] CAISO FERC Order 2222 Compliance Filing: http://www.caiso.com/Documents/Aug15-2022-ComplianceFiling-FERC-Order-No-2222-ER21-2455.pdf

*Table 71. VGI potential (%) considering both access to L2 chargers and program enrollment probability for the Mid Enrollment scenario.*

| VGI Potential (%) | Incentive Tranches ($/kW-yr) | Incremental Enrollment at Incentive Levels (%) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 2024 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
| V1G_Res_T1 | $0 | 8.6% | 8.6% | 8.6% | 8.6% | 8.6% | 8.6% | 8.6% |
| V1G_Res_T2 | $10 | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |
| V1G_Res_T3 | $30 | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% |
| V1G_Res_T4 | $50 | 0.9% | 0.9% | 0.9% | 0.9% | 0.9% | 0.9% | 0.9% |
| V1G_Com_T1 | $0 | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% |
| V1G_Com_T2 | $10 | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |
| V1G_Com_T3 | $30 | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% |
| V1G_Com_T4 | $50 | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% |
| V2G_Res_T1 | $50 | 0.0% | 0.2% | 0.6% | 0.9% | 1.9% | 2.8% | 3.8% |
| V2G_Res_T2 | $60 | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 0.1% |
| V2G_Res_T3 | $80 | 0.0% | 0.0% | 0.1% | 0.1% | 0.2% | 0.3% | 0.4% |
| V2G_Res_T4 | $100 | 0.0% | 0.0% | 0.1% | 0.2% | 0.4% | 0.5% | 0.7% |
| V2G_Com_T1 | $50 | 0.0% | 0.2% | 0.5% | 0.9% | 1.8% | 2.7% | 3.7% |
| V2G_Com_T2 | $60 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| V2G_Com_T3 | $80 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% |
| V2G_Com_T4 | $100 | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 0.2% |

*Table 72. VGI potential (%) considering both access to L2 chargers and program enrollment probability for the High Enrollment scenario (differences in **bold**)*

| VGI Potential (%) | Incentive Tranches ($/kW-yr) | Incremental Enrollment at Incentive Levels (%) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 2024 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
| V1G_Res_T1 | $0 | 8.6% | 8.6% | 8.6% | 8.6% | 8.6% | 8.6% | 8.6% |
| V1G_Res_T2 | $10 | **1.2%** | **1.2%** | **1.2%** | **1.2%** | **1.2%** | **1.2%** | **1.2%** |
| V1G_Res_T3 | $30 | **3.9%** | **3.9%** | **3.9%** | **3.9%** | **3.9%** | **3.9%** | **3.9%** |
| V1G_Res_T4 | $50 | **6.8%** | **6.8%** | **6.8%** | **6.8%** | **6.8%** | **6.8%** | **6.8%** |
| V1G_Com_T1 | $0 | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% |
| V1G_Com_T2 | $10 | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |
| V1G_Com_T3 | $30 | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% |
| V1G_Com_T4 | $50 | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% |
| V2G_Res_T1 | $50 | **0.0%** | **0.3%** | **0.9%** | **1.5%** | **3.1%** | **4.6%** | **6.2%** |
| V2G_Res_T2 | $60 | **0.0%** | **0.0%** | **0.1%** | **0.2%** | **0.3%** | **0.5%** | **0.6%** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| V2G_Res_T3 | $80 | **0.0%** | **0.1%** | **0.3%** | **0.5%** | **1.0%** | **1.5%** | **2.0%** |
| V2G_Res_T4 | $100 | **0.0%** | **0.2%** | **0.5%** | **0.8%** | **1.6%** | **2.5%** | **3.3%** |
| V2G_Com_T1 | $50 | 0.0% | 0.2% | 0.5% | 0.9% | 1.8% | 2.7% | 3.7% |
| V2G_Com_T2 | $60 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| V2G_Com_T3 | $80 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% |
| V2G_Com_T4 | $100 | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 0.2% |

The VGI potential (MW) in this study is estimated by the total VGI capable charger capacity, representing smart charger for V1G and bi-directional charger for V2G. To translate VGI potential into MW of capacity, the VGI potential (%) is multiplied by the electric LDV forecast from the 2022 IEPR[130], EV to charger ratio, and EV charger capacity as the following:

> VGI potential (MW)[131] = VGI potential (%) * (LDV EV forecast / EV to Charger ratio) * EV charger capacity (kW) / 1000

The default EV charger capacity is calculated as a weighted average for Battery Electric Vehicles (BEV) and Plug-in Hybrid Electric Vehicles (PHEV) at around 7kW based on the CEC AB 2127 report.[132] The EV to charger ratio is assumed to be 1 at residential locations and around 25 at the workplace based on the CEC AB 2127 report. The final capacity value will be scaled by the adoption of electric vehicles.[133]

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[130] Values have been updated to the 2022 IEPR provided by CEC. Total electric LDV forecasts include electric vehicle adoption under the AATE Scenario 3.

[131] The nameplate capacity here is defined as the capacity of the charger, which is slightly different from the definition in the 2022 September Inputs and Assumptions Workshop. Stakeholders had complained about the original nameplate capacity definition being confusing. In the 2022 September Inputs and Assumptions Workshop, the nameplate capacity was defined as the capacity to charge or discharge in either direction and was 2x the charger capacity for V2G.

[132] CEC AB2127 report - EV Charging Infrastructure Assessments: https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle-charging-infrastructure-assessment-ab-2127. This study currently assumes both BEV and PHEV can participate in VGI due to the ease of benchmarking the EVLST load shapes with IEPR load shapes that include both BEV and PHEV charging load. The analysis can be simplified to limit the potential to only BEV.

[133] The EV to charger ratio, EV charger capacity and many assumptions are assumed to be static based on assumptions for 2030 for this first round of VGI study given the time limitation to generate flexible parameters across years and the fact that IEPR load shape is based on historical charging session data that does not reflect technology improvement. Future improvements need to be made to make these assumptions time variant. Data for 2030 is chosen because it is the middle of this IRP's core 10-year planning horizon, and it is also the year with the most data availability across multiple sources.

*Table 73. VGI potential (MW) for the Mid Enrollment scenario, calculated using EV adoption forecast of 2022 IEPR AATE Scenario 3*[134]

| VGI Potential (MW) | 2024 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| V1G_Res_T1 | 1,191 | 1,897 | 2,914 | 4,294 | 9,212 | 14,187 | 18,767 |
| V1G_Res_T2 | 17 | 27 | 42 | 61 | 132 | 203 | 268 |
| V1G_Res_T3 | 60 | 95 | 147 | 216 | 464 | 714 | 944 |
| V1G_Res_T4 | 118 | 188 | 289 | 425 | 913 | 1,405 | 1,859 |
| V1G_Com_T1 | 45 | 72 | 111 | 164 | 352 | 542 | 717 |
| V1G_Com_T2 | 0 | 1 | 1 | 2 | 3 | 5 | 7 |
| V1G_Com_T3 | 1 | 2 | 3 | 5 | 10 | 15 | 20 |
| V1G_Com_T4 | 2 | 3 | 5 | 8 | 16 | 25 | 34 |
| V2G_Res_T1 | 0 | 42 | 192 | 472 | 2,025 | 4,678 | 8,251 |
| V2G_Res_T2 | 0 | 1 | 5 | 13 | 56 | 129 | 228 |
| V2G_Res_T3 | 0 | 4 | 19 | 46 | 195 | 451 | 796 |
| V2G_Res_T4 | 0 | 8 | 36 | 89 | 380 | 878 | 1,549 |
| V2G_Com_T1 | 0 | 2 | 7 | 17 | 74 | 170 | 300 |
| V2G_Com_T2 | 0 | 0 | 0 | 0 | 1 | 2 | 3 |
| V2G_Com_T3 | 0 | 0 | 0 | 0 | 2 | 5 | 8 |
| V2G_Com_T4 | 0 | 0 | 0 | 1 | 3 | 8 | 14 |

*Table 74. VGI potential (MW) for the High Enrollment scenario, calculated using EV adoption forecast of 2022 IEPR AATE Scenario 3. Difference from the Mid Enrollment scenario is highlighted in* ***bold****.*

| VGI Potential (MW) | 2024 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| V1G_Res_T1 | 1,191 | 1,897 | 2,914 | 4,294 | 9,212 | 14,187 | 18,767 |
| V1G_Res_T2 | **173** | **276** | **423** | **624** | **1,338** | **2,061** | **2,726** |
| V1G_Res_T3 | **534** | **851** | **1,307** | **1,925** | **4,131** | **6,361** | **8,415** |
| V1G_Res_T4 | **945** | **1,504** | **2,311** | **3,405** | **7,305** | **11,250** | **14,882** |
| V1G_Com_T1 | 45 | 72 | 111 | 164 | 352 | 542 | 717 |
| V1G_Com_T2 | 0 | 1 | 1 | 2 | 3 | 5 | 7 |
| V1G_Com_T3 | 1 | 2 | 3 | 5 | 10 | 15 | 20 |
| V1G_Com_T4 | 2 | 3 | 5 | 8 | 16 | 25 | 34 |
| V2G_Res_T1 | **0** | **68** | **313** | **770** | **3,303** | **7,631** | **13,460** |

[134] Values have been updated to the 2022 IEPR provided by CEC. Total electric LDV forecasts include electric vehicle adoption under both the Baseline and AATE Scenario 3.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| V2G_Res_T2 | **0** | **7** | **32** | **79** | **340** | **785** | **1,385** |
| V2G_Res_T3 | **0** | **22** | **99** | **244** | **1,046** | **2,416** | **4,262** |
| V2G_Res_T4 | **0** | **36** | **167** | **410** | **1,759** | **4,062** | **7,165** |
| V2G_Com_T1 | 0 | 2 | 7 | 17 | 74 | 170 | 300 |
| V2G_Com_T2 | 0 | 0 | 0 | 0 | 1 | 2 | 3 |
| V2G_Com_T3 | 0 | 0 | 0 | 0 | 2 | 5 | 8 |
| V2G_Com_T4 | 0 | 0 | 0 | 1 | 3 | 8 | 14 |

### 5.8.2 VGI Resource Costs

VGI cost assumptions in IRP reflect the costs potentially paid by utilities or third-party aggregators to enable active management of EV load in response to dynamic grid signals. These costs do not include incremental technology costs to enable VGI capability and are not intended to represent CPUC-endorsed incentives. The costs include fixed O&M costs to reflect the cost of incentivizing active management and administering/marketing the program, and variable O&M costs to reflect the cycling degradation cost only for V2G resources.

*Table 75. Fixed O&M costs assumptions ($/kW charger-yr)*

| Category | Fixed O&M Costs ($/kW charger-yr)[135] |
|---|---|
| Administration Costs | Residential: $2.8/kW/yr<br>Medium commercial: $2.8/kW/yr |
| Marketing Costs | Residential: $0.1/kW/yr<br>Medium commercial: $0.6/kW/yr |
| Incentive Costs | $0/kW-yr ~ $100/kW-yr, varying by incentive tranches and by VGI type |

*Table 76. Fixed O&M costs ($/kW charger-yr) including administration, marketing, and incentive costs.*

| Fixed O&M ($/kW charger-yr) | 2024 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| V1G_Res_T1 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| V1G_Res_T2 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| V1G_Res_T3 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| V1G_Res_T4 | 53 | 53 | 53 | 53 | 53 | 53 | 53 |

[135] Cost information is obtained and estimated from LBNL's DR Potential Study, Phase 4. Fixed O&M costs are assumed to be constant in real terms throughout the study horizon to be consistent with LBNL assumptions.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| V1G_Com_T1 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| V1G_Com_T2 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| V1G_Com_T3 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| V1G_Com_T4 | 53 | 53 | 53 | 53 | 53 | 53 | 53 |
| V2G_Res_T1 | 53 | 53 | 53 | 53 | 53 | 53 | 53 |
| V2G_Res_T2 | 63 | 63 | 63 | 63 | 63 | 63 | 63 |
| V2G_Res_T3 | 83 | 83 | 83 | 83 | 83 | 83 | 83 |
| V2G_Res_T4 | 103 | 103 | 103 | 103 | 103 | 103 | 103 |
| V2G_Com_T1 | 53 | 53 | 53 | 53 | 53 | 53 | 53 |
| V2G_Com_T2 | 63 | 63 | 63 | 63 | 63 | 63 | 63 |
| V2G_Com_T3 | 83 | 83 | 83 | 83 | 83 | 83 | 83 |
| V2G_Com_T4 | 103 | 103 | 103 | 103 | 103 | 103 | 103 |

*Table 77. The calculation of variable O&M costs ($/kWh) for V2G resources*[136]

| | 2022 | 2030 | 2040 | 2050 |
|---|---|---|---|---|
| EV Pack and Cell Price ($2022/kWh) | $151 | $98 | $86 | $74 |
| Cycles | 3,500 | 3,500 | 3,500 | 3,500 |
| Cost per cycle ($2022/kWh) | $0.04 | $0.03 | $0.02 | $0.02 |

[136] EV pack and cell price in 2022 are obtained from the BNEF report and it's extrapolated based on the trend of BTM storage cost trajectory from CPUC IRP Pro Forma. BNEF report: https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/. The degradation cost is estimated using stationary storage cycle limit of 3500 cycles, assuming the impact of using EV as a stationary storage resource will have less degradation impact on EVs compared to driving the vehicles. A typical EV warranty cycle limit nowadays is around 100,000 miles, around 500 cycles.

# 6. Generators Operating Assumptions

## 6.1 Overview

While RESOLVE is a simplified dispatch model and requires a simpler set of data and constraints, a more expansive set of data assumptions are required for the SERVM model. This section summarizes the sources of data for each of these models.

### 6.1.1 SERVM Operations

SERVM is a full PCM model which seeks to completely characterize the electric system with generators represented in an hourly dispatch model. Generation assumptions are sourced from various sources to update the baseline.

Staff made several major changes and updates to CPUC's SERVM dataset since the RA LOLE and ELCC study performed in early 2022, described in the following sub-sections.

#### *6.1.1.1 Baseline Reconciliation and 2032 Anchor Dataset*

Staff updated the baseline list of generators during spring 2023 and finalized it in May 2023. This baseline replaces the prior list dated September 2022. Staff added new generators that have come online or were in development as of November 2022. Existing resources in CAISO were sourced from the CAISO Master Generating Capability List as of January 2023. Units in development were sourced from November 2022 LSE IRP filings. Confirmation of some data regarding in-development resources for CAISO and outside CAISO regions were sourced from the CPUC RPS database and current EIA data, as well as the 2032 WECC ADS.

The baseline update also involved making additions and updates to individual units from the old baseline list, including updates to operating parameters and maximum capacity. Staff also updated regions, unit types, and unit categories to correct errors and oversights. Staff consolidated planned capacity with newly online capacity if a planned project came online, as well as separated hybrid units into Limited Energy Storage Resource (LESR) and Solar PV (SUN) portions by creating two units and appending "LESR" or "SUN" to the SERVM Unit IDs.

In SERVM, staff also aggregated the PG&E Bay and PG&E Valley regions into one PGE region by combining both the hourly demand and demand modifiers and consolidating the region name for affected units into the name PGE region. In RESOLVE, the entire P&GE region is combined with SCE and SDGE into one large CAISO area, as it always has been.

#### *6.1.1.2 Calibration of imports, simplification of external regions*

Staff reconciled the dataset of demand and generating resources for SERVM and the 2032 WECC ADS in order to reasonably model grid conditions in external regions and produce a realistic pattern of import exchanges between CAISO and external areas. To reduce complexity and in recognition of modeling run times and data processing, staff chose to model only external regions closest to California. Those regions closest to California, listed in Table 78 were maintained in the model while regions further from California were left out. In addition, regions in the Northwest and Southwest were grouped as a co-region in order to simplify their dispatch patterns. The default amounts of generation and electric demand drawn from the 2032 WECC ADS did not result in all regions with about 0.1 LOLE level of reliability.  To reduce leaning of one region upon another and to model more realistic transfer patterns between regions, some calibration of electric demand and/or shifting of capacity between regions was needed to tune all regions towards a 0.1 LOLE target. Staff worked to equalize the reliability level across regions and model realistic transfer amounts between regions.

### 6.1.2 RESOLVE Operations

RESOLVE's objective function includes the annual cost to operate the electric system across RESOLVE's footprint; this cost is quantified using a linear production cost model. Components of RESOLVE's operational model include:

- **Aggregated generation classes:** Rather than modeling each generator independently, generators in each zone are grouped together into categories with other plants whose operational characteristics are similar (e.g., nuclear, coal, gas CCGT, gas peaker). Grouping like plants together reduces the computational complexity of the problem without significantly impacting the underlying economics of power system operations.
- **Linearized unit commitment:** RESOLVE includes a linear version of a traditional production simulation model. In RESOLVE's implementation, the commitment variable for each class of generators is a continuous variable rather than an integer variable. Constraints on operations (e.g., Pmin, Pmax, ramp rate limits, minimum up & down time, start profile) limit the flexibility of each class' operations.
- **Co-optimization of energy & ancillary services:** RESOLVE dispatches generation to meet demand across the Western Interconnection while simultaneously reserving headroom and footroom on resources within CAISO to meet the contingency and flexibility reserve needs of the CAISO balancing authority.
- **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes six zones: four zones capturing California balancing authorities and two zones that

represent regional aggregations of out-of-state balancing authorities.[137] The constituent balancing authorities included in each RESOLVE zone are shown in Table 78.

*Table 78. Constituent balancing authorities in each RESOLVE and SERVM zone*

| RESOLVE Zone | Balancing Authorities |
|---|---|
| BANC | Balancing Authority of Northern California (BANC)<br>Turlock Irrigation District (TID) |
| CAISO | California Independent System Operator (CAISO) |
| LADWP | Los Angeles Department of Water and Power (LADWP) |
| IID | Imperial Irrigation District (IID) |
| NW | Avista Corporation (AVA)<br>Bonneville Power Administration (BPAT)<br>Chelan County Public Utility District (CHPD)<br>Douglas County Public Utility District (DOPD)<br>Grant County Public Utility District (GCPD)<br>Pacificorp West (PACW)<br>Portland General Electric Company (PortlandGE) |
| SW | Arizona Public Service Company (APS)<br>Nevada Power Company (NEVP)<br>Salt River Project (SRP)<br>WAPA – Lower Colorado (WALC) |
| Excluded (not modeled) | Alberta Electric System Operator (AESO)<br>British Columbia Hydro Authority (BCHA)<br>Comision Federal de Electricidad (CFE)<br>Public Service Company of New Mexico (PNM)<br>Public Service Company of Colorado (PSCO)<br>WAPA – Colorado-Missouri (WACM) |

[137] A seventh resource-only zone was added in the 2019 IRP to simulate dedicated imports from Pacific Northwest hydro. This zone does not have any load and does not represent a BAA.

## 6.2 Load Profiles and Renewable Generation Shapes

Hourly load, wind, and solar generation profiles ("shapes") are key data input to both SERVM and RESOLVE's hourly production simulation model. The following sections describe the sources and assumptions for how these profiles are derived and coordinated between the two models.

During the course of 2022, Staff performed the detailed updates to add more recent weather years (2018-2020) into the overall ensemble of weather data for use in the SERVM model. This effort was extremely helpful given the heat observed in 2020 and the ability to add that new extreme event into the overall ensemble of conditions tested in SERVM. It is likely more extreme heat years will appear in the future weather years (including 2022) however at this time Staff are currently only able to simulate through 2020 due to lack of necessary demand data for more recent years.

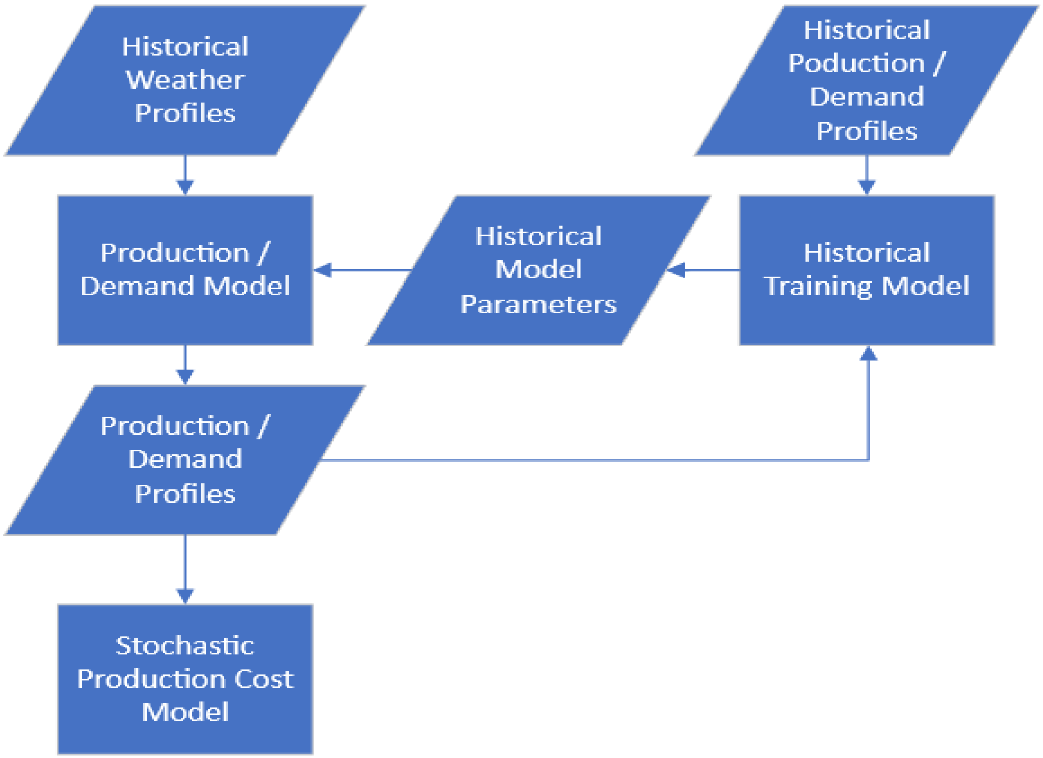
### 6.2.1 Load Profiles

In the past, RESOLVE has sourced load profiles from existing WECC profiles from the years 2007-2009 while the SERVM model has developed electric demand profiles directly using a weather normalization model and existing temperature and humidity data. During the 2022-2023 IRP cycle, Staff have replaced these demand and generation profiles with the current dataset in SERVM. These 23 weather years (1998-2020) are the initial dataset from which the representative days are drawn to be used in RESOLVE.

These 23 weather year load profiles are developed in a two-step process. Staff gathered electric sales data from the CAISO EMS data and for non-CAISO regions from FERC hourly electric sales data, added back the impacts of simulated BTM PV and actual Demand Response events, and reconstituted consumption demand for the immediately previous three years (2018-2020). This consumption demand for the previous three years was then used to train a Monash[138] regression model which would then use historical temperatures and other weather variables to predict electric demand. That way, the previous three years can form the relationship that is then used to build out 23 years of historical simulated consumption demand.

[138] Monash electric demand model is described in a paper here: MEFMR1.pdf (robjhyndman.com)

*Figure 22. Creation of Demand Profiles from Historical Weather*




The resulting normalized demand profiles are then input into SERVM and scaled to the IEPR peak and energy forecast. Currently, 2021 IEPR and 2022 IEPR forecasts are available for modeling in SERVM. RESOLVE's hourly demand profiles are developed from SERVM's 23 weather year profiles for CAISO.

Electric demand profiles for non-CAISO zones are also developed using the same Monash model approach, though hourly electric demand for the final three years of the dataset (i.e., 1998 to 2020) are sourced from FERC Form 714 instead of CAISO EMS data and are similarly reconstituted to consumption demand using simulated BTMPV generation data for each region. These hourly profiles are assumed to reflect the baseline consumption profiles for those years. The normalized profiles are scaled to the peak and energy forecasts of the desired IEPR for California non-CAISO regions, and to the 2032 WECC ADS case for regions outside California.

#### *6.2.1.1 Energy Efficiency Profiles*

Energy efficiency is modeled as a demand-modifier (not a candidate resource). Two different hourly load profiles are drawn from CEC 2022 IEPR data for Planning and Local Reliability forecasts. In RESOLVE and SERVM, for energy efficiency as well as other demand modifiers the profiles (all of them except for BTM PV) are drawn directly from hourly profiles provided by the CEC's IEPR and processed into normalized profiles paired with a maximum capacity that together recreate the IEPR demand modifier profile for each forecast year. The RESOLVE model uses each future year's profile directly. The energy efficiency profiles from 2021 IEPR Mid and 2021 ATE are preserved in the RESOLVE model.

#### *6.2.1.2 Electric Vehicle Load Profiles*

Medium-duty and heavy-duty EV load profiles included in the CEC's 2022 IEPR Demand Forecast are used as the default EV charging profiles in the next cycle of updates for both Planning and Local Reliability forecasts. The 2021 IEPR Mid and ATE hourly profiles are preserved in the RESOLVE model.

The default assumption is to model these profiles statically with no flexible EV charging allowed except for scenarios where VGI is allowed. However, driver behavior response to TOU rates and other incentives, to the extent captured in the IEPR EV load profiles, is reflected in these static profiles.

#### *6.2.1.3 Building Electrification Load Profiles*

Both building electrification load profiles for AAFS come from the CEC's 2022 IEPR Demand Forecasts, one for Planning and the other for Local Reliability forecast. The building electrification load profiles from 2021 IEPR Mid and 2021 ATE are preserved in the RESOLVE model.

#### *6.2.1.4 Time-of-Use Rates Adjustment Profiles*

Time-of-use (TOU) rate profile impacts are based on the CEC's 2022 IEPR demand forecast data. The TOU profiles for 2035 are used for 2036-2050.

#### *6.2.1.5 Hydrogen Load Flexibility Assumptions*

No exogenous hydrogen load flexibility is modeled; instead, hydrogen production load from electrolyzers is modeled endogenously such that the overall system costs for hydrogen production and the electric system are minimized. Essentially the modeling assumes that no hydrogen is produced, carbon-free or otherwise, outside of the system being modeled. All hydrogen used for electricity generation must also be created endogenously by the RESOLVE model through the addition of hydrogen-producing infrastructure to its optimized portfolio.

### 6.2.2 Solar Profiles

Solar profiles are created using NREL's PVWATTSv5 calculator.[139] The software creates PV production profiles based on weather data from the National Solar Radiation Database

[139] See: https://pvwatts.nrel.gov/downloads/pvwattsv5.pdf

(NSRDB),[140] and is used to produce both utility-scale and behind-the-meter solar profiles. 1998-2020 NSRDB weather data is used to create the profiles used in SERVM, and these profiles are sampled to create the representative days in RESOLVE.

To create solar profiles using the PVWATTSv5 calculator, parameters are needed that represent north-south single-axis tracking configuration and an inverter loading ratio of 1.3. SERVM simulates solar production profiles for single and double axis tracking configurations as well as a fixed axis configuration. SERVM also simulates production from BTMPV resources with a BTMPV profile. For each of these classes of solar resources, SERVM creates a separate normalized production profile representing hourly weather from 23 weather years and for more than two dozen specific locations in California and across WECC. RESOLVE aggregate profiles are obtained by averaging production profiles across the representative locations. Installed capacity for individual baseline solar installations is used to create a single weighted-average baseline CAISO solar profile. Inverter loading ratio for BTMPV resources is sourced from the CEC IEPR information, currently equaling 1.13.

Before the solar profiles can be used in RESOLVE, they are scaled such that the weighted capacity factor of the modeled days matches a long-run average capacity factor. This step is taken to ensure that the day sampling process does not result in over- or under-production for individual solar resources relative to the long-run average. The reshaping is done by linearly scaling the shape up or down until the target capacity factor is met. When scaling up, the maximum capacity factor is capped at 100% to ensure that a profile's hourly production does not exceed its rated installed capacity. The scaling process mimics increasing/decreasing the inverter loading ratio. Solar resource profile capacity factors are scaled using the average simulated capacity factor from the nearest representative weather station from the historical 23-year weather conditions. Solar capacity factors are shown in Table 79. [141]

[140] See: https://nsrdb.nrel.gov/current-version

[141] Note the naming convention for baseline renewable resources is [BAA]_[Solar/Wind]_for_[REC recipient: CAISO or Other]. For example generation from the "CAISO_Solar_for_Other" resource is included in CAISO's load resource balance equation and RECs from this resource are not included in CAISO's RPS constraint. Generation from the "IID_Solar_for_CAISO" resource is balanced by IID and RECs from this resource are included in CAISO's RPS constraint.

*Table 79. Solar Capacity Factors in RESOLVE*

| Category | Resource | Capacity Factor |
|---|---|---|
| **Baseline Resources** | BANC_Solar | *32%* |
| | CAISO_Solar | *31%* |
| | IID_Solar | *31%* |
| | LDWP_Solar | *32%* |
| | NW_Solar | *28%* |
| | SW_Solar | *33%* |
| **Candidate Resources** | Arizona_Solar | *33%* |
| | Distributed_Solar | *24%* |
| | Greater_Imperial_Solar | *34%* |
| | Greater_Kramer_Solar | *35%* |
| | Greater_LA_Solar | *32%* |
| | Northern_California_Solar | *28%* |
| | Riverside_Solar | *34%* |
| | Southern_NV_Eldorado_Solar | *33%* |
| | Southern_PGAE_Solar | *32%* |
| | Tehachapi_Solar | *35%* |

### 6.2.3 Wind Profiles

The CPUC wind model produces 23 years of normalized hourly production profiles (1998 – 2020) for all locations at which wind resources exist within our model. For each wind resource in the model, hourly wind production curves (MWh) can be produced by simply scaling the respective normalized hourly production profile closest to the resource by the installed capacity (in MW) of the resource. Individual efforts were undertaken for each of the Offshore Wind (Offshore) profiles, CAISO onshore profiles (Onshore), and onshore Out of State profiles (OOS).

Hourly normalized production profiles are developed from wind speeds obtained from the WRF-ERA5 model provided as part of the CEC Cal-Adapt modeling efforts. Each wind resource in the model (Offshore, Onshore CAISO and OOS) is mapped to the closest grid point in the WRF dataset. A single response curve relating wind speed to normalized wind production is determined from a least squared analysis. For Onshore CAISO resources, hourly CAISO settlement data is used to create normalized production by dividing by the maximum production (in MWh) for each resource and year. The initial seed response curve used in the least squared analysis is based on a generic System Advisor Model (SAM) WIND toolkit turbine response curve. The wind response curve obtained from the least squares analysis has system losses embedded directly in it as it is trained directly on CAISO hourly settlement data which includes system losses. Because the wind model is trained on California only settlement data, we expect the normalized production curves to be most accurate within the state. For that reason, wind profiles for out of state (OOS) wind was developed separately using EIA data instead of CAISO settlement data.

Offshore normalized production curves are also developed using the WRF-ERA5 wind dataset. Because no offshore production data is available for training the model, we instead use a wind response curve provided directly from NREL. The NREL response curve does not include system losses, so instead we add an additional system loss component based on research prepared for the Bureau of Ocean Energy Management (BOEM).[142] The profiles used here represent a new version of data available, replacing older MERRA data with newer WRF-ERA5 data.

RESOLVE sources wind shapes from the hourly profiles developed for the SERVM model. Profiles are selected from the SERVM model to correspond to aggregated wind resources in the RESOLVE model. The profiles are then scaled using a filter such that the weighted capacity factor of the modeled days matches a long-run average capacity factor. The filter mimics small differences in turbine power curves, slightly increasing or decreasing wind production in a manner that preserves hourly ramps. Wind capacity factors are shown in Table 80.

[142] table 10, found here: https://www.boem.gov/sites/default/files/documents/regions/pacific-ocs-region/environmental-science/BOEM-2020-045.pdf

*Table 80. Wind Capacity Factor in RESOLVE*

| Category | Resource | Capacity Factor |
|---|---|---|
| **Baseline Resources** | CAISO_Wind | *32%* |
| | LDWP_Wind | *35%* |
| | NW_Wind | *31%* |
| | SW_Wind | *31%* |
| **Candidate Resources** | Baja_California_Wind | *30%* |
| | Central_Valley_North_Los_Banos_Wind | *24%* |
| | Greater_Imperial_Wind | *30%* |
| | Greater_Kramer_Wind | *29%* |
| | Humboldt_Wind | *22%* |
| | Idaho_Wind | *34%* |
| | Kern_Greater_Carrizo_Wind | *29%* |
| | New_Mexico_Wind | *46%* |
| | Northern_California_Wind | *22%* |
| | Riverside_Wind | *29%* |
| | Solano_Wind | *26%* |
| | Southern_NV_Eldorado_Wind | *33%* |
| | Tehachapi_Wind | *29%* |
| | Utah_Wind | *35%* |
| | Wyoming_Wind | *49%* |
| **Candidate Offshore Wind Resources** | Cape_Mendocino_Offshore_Wind | *59%* |
| | Del_Norte_Offshore_Wind | *57%* |
| | Humboldt_Bay_Offshore_Wind | *58%* |
| | Morro_Bay_Offshore_Wind | *46%* |

## 6.3 Representative sampling hourly load & generation profiles

RESOLVE differs from production cost models in that production cost models simulate a fixed set of resources, whereas the capacity of new and existing resources can be adjusted by RESOLVE in response to short-run (within year) and long-run (years to decades) economics and constraints. Simulating investment decisions concurrently with operations necessitates simplification of production cost modeling to maintain a reasonable runtime. In past IRP cycles, RESOLVE has used a set of 37 representative days.

In the 2022-2023 IRP cycle, RESOLVE will move to a new clustering approach to select a subset of days from the raw 23-year load, hydro, and renewable profiles in the updated IRP dataset (covering 1998-2020 weather years). The clustering approach uses features of the load & generation profiles to identify:

a. "Exemplars" or "medoids" that best represent the shape of the overall 23-year dataset. For the sake of explanation, exemplars can be thought of as "days", though RESOLVE has the ability to select exemplars of other lengths (e.g., weeks)
    i. In order to do this, RESOLVE employed affinity propagation as the clustering method in this project, although it does have the capability of employing other methods.
    ii. Affinity propagation algorithm clusters by conducting an iterative process that updates the "responsibility" and "affinity" between any two data points. For a particular data point A, if it has high affinity to many other data points, then it would be more responsible/suitable to become an exemplar. Other data points would then reevaluate their affinity towards data point A, based on its updated responsibility. This process iterates until there's only one exemplar remaining for each data point. A detailed process can be found here[143].
b. A mapping of each exemplar back to the original 23-year profile, providing
    i. A weighting of the importance of the exemplar in representation of the expected operational costs for the portfolio
    ii. Allowing RESOLVE to reconstruct a "pseudo-8760" dispatch based on the chronological mapping of which exemplar best represents the original date in the profile

The specific sample days used in the model are shown in Table 81 below.

*Table 81 . Representative sample days for 2022-2023 CPUC IRP RESOLVE modeling*

| S/No | Historical Date | Representative Month |
|---|---|---|
| 1 | 1/23/2020 | January |
| 2 | 1/24/2007 | January |
| 3 | 1/28/2013 | January |
| 4 | 2/4/2013 | February |

[143] https://www.science.org/doi/10.1126/science.1136800

| | | |
|---|---|---|
| 5 | 2/15/2004 | February |
| 6 | 3/1/2003 | March |
| 7 | 3/19/2005 | March |
| 8 | 3/29/2018 | March |
| 9 | 4/9/2004 | April |
| 10 | 4/16/2009 | April |
| 11 | 4/17/2002 | April |
| 12 | 4/20/2016 | April |
| 13 | 5/1/2012 | May |
| 14 | 5/10/2007 | May |
| 15 | 5/24/2018 | May |
| 16 | 5/29/2012 | May |
| 17 | 6/15/2003 | June |
| 18 | 6/23/2000 | June |
| 19 | 6/30/2012 | June |
| 20 | 7/17/2008 | July |
| 21 | 7/18/2004 | July |
| 22 | 7/26/2009 | July |
| 23 | 8/3/2010 | August |
| 24 | 8/8/2020 | August |
| 25 | 8/27/2012 | August |
| 26 | 9/3/2012 | September |
| 27 | 9/16/2007 | September |
| 28 | 9/26/2000 | September |
| 29 | 10/7/2012 | October |
| 30 | 10/20/2013 | October |
| 31 | 11/1/2020 | November |
| 32 | 11/15/2018 | November |
| 33 | 11/16/2019 | November |
| 34 | 12/7/2003 | December |
| 35 | 12/9/2002 | December |
| 36 | 12/15/2007 | December |

## 6.4 Operating Characteristics

### 6.4.1 Natural Gas, Coal, and Nuclear

The thermal fleet is represented by a limited number of resources within each zone. Within each zone, each resource is characterized individually with operating parameters calculated from unit-level data. Constraints on gas and coal plant operation are based on a linearized version of the unit commitment problem. The principal operating characteristics (Pmax, Pmin, heat rate, start cost, start fuel consumption, etc.) for each unit are taken from the latest vintage version of the CAISO MasterFile and the WECC 2032 Anchor Data Set Phase 2 2 V2.3.2.[144] Variable Operations and Maintenance Costs (VO&M) are sourced from the CAISO Master File.[145] Some plant types are modeled using operational information from other sources:

- The **CAISO_Aero_CT** and **CAISO_Advanced_CCGT** operating characteristics are based on manufacturer specifications of the latest available models of these classes.
- The **CAISO_CHP** plant type is modeled as a must-run resource with an unchanged net heat rate of 7,600 Btu/kWh preserved from the 2019-2021 IRP cycle; which based the assumption on CARB's Scoping Plan assumptions for cogeneration. A monthly generation schedule for CAISO_CHP is developed using historical settlement data.

While SERVM simulates each unit individually based on actual unit data, RESOLVE aggregates unit types together into classes of thermal generating units (CCGT, Steam Turbine, Peaker, etc.). and uses weighted average statistics drawn from the unit level data used in SERVM. In RESOLVE, constraints on gas and coal plant operation are based on a linearized version of the unit commitment problem. Monthly derates for each plant reflect assumptions regarding the timing of annual maintenance requirements. Nuclear maintenance and refueling is assumed to be split between the spring (April & May) and the fall (September & October) so that the plants can be available to meet summer and winter peaks (as noted earlier, the modeling assumptions use the current retirement dates for Diablo Canyon Nuclear Power Plan Units 1 and 2). Annual maintenance of the coal fleets in the WECC is assumed to occur during the spring months, when wholesale market economics tend to suppress coal capacity factors due to low loads, high hydro availability, and high solar availability.

[144] https://www.wecc.org/Reliability/2032%20ADS%20PCM%20V2.3.2%20Public%20Data.zip

[145] See http://oasis.caiso.com/mrioasis/logon.do

### 6.4.2 Hydro

Power production from the hydro fleet in each zone is constrained on each day by three constraints:

**Daily energy budget:** the total amount of energy, in MWh, to be dispatched throughout the day. These energy budgets are derived from historical monthly average flows from the historical 1998-2020 weather record.

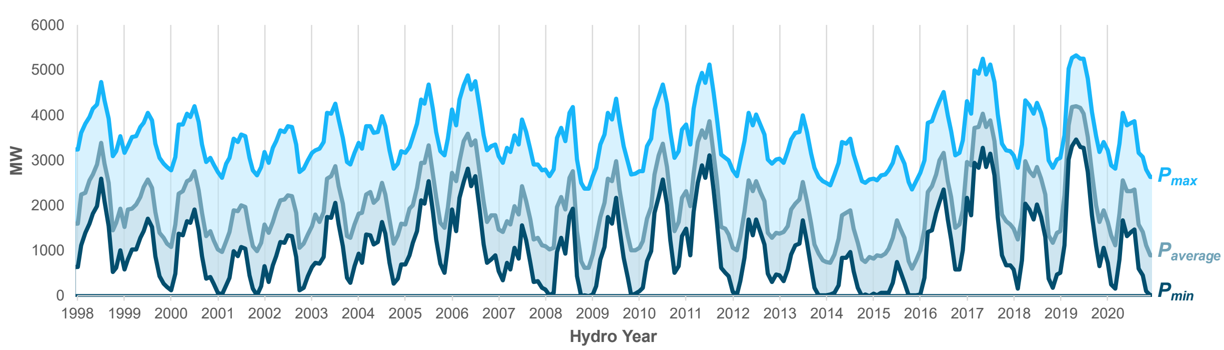
**Daily maximum and maximum output:** upper and lower limits, in MW, for power production intended to capture limits on the flexibility of the regional hydro system due to hydrological, biological, and other factors.

**Ramping capability:** within CAISO, the ramping capability of the fleet is further constrained by hourly and multi-hour ramp limitations (up to four hours), which are derived from historical CAISO hydro operations.

Input parameters match the data in the Unified IRP dataset, consistent with the inputs in the SERVM model.

In the CAISO, these constraints are drawn from the actual historical record: the daily budget and minimum/maximum output are based on actual CAISO operations on the day of the year from the appropriate hydrological year (low = 2008, mid = 2009, high = 2011) that matches the canonical day used for load, wind, and solar conditions. As an example, one of the RESOLVE representative days (#3 in the 2019-2021 IRP) uses February 12, 2007 for load, wind, and solar conditions and uses 2011 hydro conditions; therefore, the daily hydro budget and operational range is based on actual CAISO daily operations on February 12, 2011).

*Figure 23. CAISO hydro operating bounds*




*In the chart above, $P_{max}$ represents the maximum power output in each month for 1998-2020 hydro years, $P_{average}$ represents the average daily power output in each month (i.e., 24 hours/day x $P_{average}$ = daily energy budget), and $P_{min}$ represents the minimum power output defined by streamflow and other operational requirements.*

Outside CAISO, assumed daily energy budgets are derived from monthly historical hydro generation as reported in EIA Form 906/923 (e.g., in the example discussed above for day #3 from the 2019-2021 IRP, the daily energy budgets for other regions are based on average conditions in February 2011). Minimum and maximum output for regions outside CAISO are based on functional relationships between daily energy budgets and the observed operable range of the hydro fleet derived from historical data gathered from WECC.

The Pacific Northwest Hydro fleet is divided into two resources: **NW_Hydro**, which serves load primarily in the NW and is located in the NW zone, and **NW_Hydro_for_CAISO**, which is modeled as a dedicated import into CAISO. Both hydro resources use the historical maximum and average capacity factor of the NW hydro fleet on the appropriate month and year for each sampled day. To maintain historical streamflow levels for the aggregate fleet of NW hydro generators, fleet-wide minimum output levels are enforced on the NW_Hydro resource. A minimum output constraint is not enforced for NW_Hydro_for_CAISO.

For this 2022-2023 IRP cycle, staff no longer assume that hydroelectric performance (and hydro abundance in general) are tied to other weather dynamics, such as overall temperature, wind, and solar performance. This will allow Staff to further assess variability of hydroelectric availability across the full distribution of other weather variables. The new effect is a large increase in combinations tested in the model, where instead of 23 weather years correlated together times 5 Load Forecast Error (LFE) values resulting in 115 distinct combinations of weather and demand, now we have 23 weather years times 23 hydro availability scenarios times 5 LFE points, or 2,645 distinct combinations to test.  This represents a greater testing of variability, making the overall result more robust and durable. Hourly hydroelectric dispatch in SERVM is still driven by weather information drawn from 1998-2020 rainfall and hydroelectric historical production, and sample hydro profiles are posted to the CPUC website.

### 6.4.3 Energy Storage

In RESOLVE's internal production simulation, storage devices can perform energy arbitrage and can commit available headroom and footroom to operational reserve requirements. For storage devices, headroom and footroom are defined as the difference between the current operating level and maximum discharge or charge capacity (respectively). For example, a 100 MW battery charging at 50 MW has a headroom of 150 MW (100 – (-50)) and a footroom of 50 MW.

Reflecting operational constraints and lack of direct market signals, BTM storage devices in the 2022-2023 IRP cycle can perform energy arbitrage but do not contribute to operational reserve requirements.

For all storage devices, RESOLVE does not by default include minimum generation or minimum "discharging" constraints, allowing them to charge or discharge over a continuous range. For pumped storage, this is a simplification because pumps and generators typically have a somewhat limited operating range. The round-trip efficiency and parasitic (self-discharge) losses for each storage technology (Li-ion, Flow, and Pumped Storage) is based on the most recent information in the Lazard's Levelized Cost of Storage report.

In SERVM, battery storage is modeled with a 90% of nameplate discharge range, except during scarcity hours when full discharge is allowed. This constraint was chosen to reflect real world behavior of operators seeking to avoid increased maintenance from operating batteries at their extremes regularly. Pumped hydro storage units in SERVM do not have this constraint.

SERVM uses a maintenance rate of 0.0218 and the model schedules maintenance during seasonal non-peak periods for both battery storage and pumped hydro storage. Battery storage has a 5% Expected Forced Outage Rate in SERVM. This was chosen based on historical battery outage data obtained from CAISO that showed weighted average outage rates of about 5-7%.

*Table 82. Assumptions for new energy storage resources*

| Technology | Round-Trip Efficiency | Minimum Duration (hours) |
|---|---|---|
| Li-Ion Battery (Utility Scale) | 85% | 1 |
| Li-Ion Battery (BTM) | 85% | 1 |
| Flow Battery | 70% | 1 |
| Pumped Storage | 75% | 10 |
| Adiabatic CAES | 60% | 24 |

## 6.5 Operational Reserve Requirements

As described in Table 83 below, both IRP models model reserve products that ensure reliable operation during normal conditions (regulation and load following) and contingency events (frequency response and spinning reserve). Reserves are modeled for each hour in both RESOLVE and SERVM models. Information on these requirements came from discussions with CAISO staff and are summarized below.

Reserves can be provided by available headroom or footroom from various resources, subject to operating limits (Table 83). For generators, headroom and footroom represent the difference between the current operating level and the maximum and minimum generation output, respectively. For storage resources, the operational range from the current operating level to maximum output (headroom) and maximum charging (footroom) is available, subject to constraints on energy availability. Reserves are modeled as mutually exclusive, meaning that headroom or footroom committed to one reserve product cannot be used towards other requirements.

While SERVM is able to simulate requirements across all regions in the model, in RESOLVE reserves are only modeled for the CAISO zone due to computational limitations. Given that the CAISO generation fleet does not include coal- or oil-fired generators, Table 83 uses the term "gas-fired" to describe the contribution of dispatchable thermal resources reserve requirements. Geothermal and biomass resources are not modeled as providing reserves.

*Table 83. Reserve types modeled in RESOLVE and SERVM*

| Product | Description | Modeling Requirement | Operating Limits |
|---|---|---|---|
| **Regulation Up/Down** | Frequency regulation operates on the 4-second to 5-minute timescale. This reserve product ensures that the system's frequency, which can deviate due to real-time swings in the load/generation balance, stays within a defined band during normal operations. In practice, this is controlled by generators on Automated Generator Control (AGC), which are sent a signal based on the frequency deviations of the system. | In RESOLVE the requirement varies hourly and is formulated using a root mean square of the following values for each hour: 1% of the hourly CAISO load; a 95% confidence interval (CI) of forecast error of the 5-minute wind profile within a given season-hour; and a 95% CI of the forecast error of the 5-minute solar profile within a given season-hour. The calculation is performed separately for regulation up and regulation down.<br>In SERVM this is modeled as 3% of hourly demand. Lack of sufficient capacity to provide regulation reserve leads directly to LOLE. | Gas-fired generators can provide available headroom/footroom, limited by their 10-minute ramp rate. Storage resources and hydro generators are only constrained by available headroom/footroom. |
| **Load Following Up/Down** | This reserve product ensures that sub-hourly variations from load, wind, and solar forecasts, as well as lumpy blocks of imports/exports/generator commitments, can be addressed in real-time. | In RESOLVE hourly requirements are based on a 95% CI of the subhourly net load forecast error within a given season-hour. The calculation is performed separately for load following up and load following down.<br>In SERVM this is modeled as 6% of hourly demand each for load following up and down. | Gas-fired generators can provide all available headroom/footroom, limited by their 10-minute ramp rate. Storage resources and hydro generators are only constrained by available headroom/footroom. |

| Product | Description | Modeling Requirement | Operating Limits |
|---|---|---|---|
| | | Load following up and down are targets, not requirements however and do not lead directly to LOLE. | |
| **Frequency Response** | Resources that provide frequency response headroom must increase output within a few seconds in response to large dips in system frequency. Frequency response is operated through governor or governor-like response and is typically only deployed in contingency events. | 770 MW of headroom is held in all hours on gas-fired, conventional hydroelectric, pumped storage, and battery resources. At least half of the headroom (385 MW) must be held on gas-fired and battery resources. This is the same in both RESOLVE and SERVM. | Reflecting governor response limitations, gas-fired generators can contribute available headroom up to 8% of their committed capacity. Wholesale battery storage, pumped storage, and conventional hydroelectric resources are constrained by available headroom. |
| **Spinning Reserve** | Spinning reserve ensures that enough headroom is committed on available resources to replace a sudden loss of power from large generation units or transmission lines. Spinning reserve is a type of contingency reserve. | The requirement is 3% of the hourly CAISO load in both RESOLVE and SERVM. Lack of sufficient capacity to provide spinning reserve leads directly to LOLE. | Gas-fired generators can provide all available headroom, limited by their 10-minute ramp rate. Storage resources and hydro generators are constrained by available headroom/footroom. RESOLVE ensures that storage has enough state-of-charge available to provide spinning reserves, but deployment (which would reduce the state-of-charge) is not explicitly modeled. |
| **Non-Spinning Reserve** | Ensures that enough headroom is committed on available resources to replace spinning reserves within a given timeframe | Not modeled due to small impact on total system cost | N/A |

In RESOLVE, the energy impact associated with deployment of reserves is modeled for regulation and load following. The default assumption for deployment of these reserves is 20%. In other words, for every MW of regulation or load following up provided in a certain hour, the resource providing the reserve must produce an additional 0.2 MWh of energy (and vice versa for regulation / load following down). For storage resources, reserve deployment changes the state of charge of the storage device. For thermal resources, reserve deployment results in increased or decreased fuel burn depending on the direction of the reserve. Conventional hydro resources are constrained by a daily energy budget, so reserve deployment will result in dispatch changes in other hours of the same day. Deployment is not modeled for spinning reserve and primary frequency response because these reserves are called upon infrequently. It is assumed that variable renewables (wind and solar) can provide load following down, but only up to 50% of the load following down requirement. This allows renewables to be curtailed on the subhourly level to provide reserves. Wind and solar resources are not assumed to provide any reserve product other than load following down.

CAISO hour-ahead forecasts and 5-minute actual values of load, wind, and solar are used to develop the load following and regulation requirements for RESOLVE. Reserve requirements use profiles that represent the production *potential*, so wind and solar curtailment is added back to historical profile data before performing the reserve requirement calculations. Requirements from the previous IRP cycle[146] are approximated as a linear combination of the following values:

- A percentage of hourly load
- A percentage of hourly wind output
- A percentage of solar nameplate capacity, differentiated by season and hour of day

Separate percentage values are determined for regulation up, regulation down, load following up, and load following down. Load following percentages were adjusted to reduce forecast bias. The wind and solar (utility-scale and BTM) resource capacity in each future year in the 2022 LSE filings requirement (for 30 MMT RESOLVE portfolio)[147] in conjunction with the 2022 IEPR Planning Scenario load forecast, is used to calculate reserve requirements for each hour of every year through the end of the study period.

## 6.6 Criteria Pollutants Emissions Factors

Criteria pollutants are calculated in SERVM by dispatching power plants, tracking their emissions on startup and steady state operation, and separating emissions according to location in Disadvantaged Communities (DAC) in California. In the case of SO2 and PM 2.5,

[146] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/inputs--assumptions-2019-2020-cpuc-irp_20191106.pdf p. 78-81. 2030 regulation and load following requirements are used to determine parameters.

[147] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/zipped-files/resolve-public-release-2022-06-23-lse-plans-filing-requirements.zip

emissions are a factor of the fuel consumed, thus tracking emissions is done by tracking fuel consumed in startups and steady state operation. In the case of NOx emissions, there is a separate reaction between the combustion temperature and nitrogen in the ambient air, meaning emissions differ at different levels of operation. Thus, there are different emissions factors for different kinds of startups (cold, warm, hot) and for steady state operations.

SOx and PM 2.5 emissions factors are presented as lbs per MMBtu of fuel burned, while NOx emissions factors are presented as lbs per MWh while.

*Table 84 NOx emissions Factors (lbs/MWh)*

| Unit Category | steady_state_nox_ef lbs/mwh | hot_start_ef lbs/mwh | warm_start_ef lbs/mwh | cold_start_ef lbs/mwh |
|---|---|---|---|---|
| CC | 0.081 | 0.256 | 0.837 | 1.417 |
| CT | 0.171 | 0.154 | 0.739 | 1.323 |
| ICE | 0.500 | 0.154 | 0.739 | 1.323 |
| Cogen | 0.241 | 0.154 | 0.739 | 1.323 |
| Steam | 0.150 | 0.154 | 0.739 | 1.323 |
| Coal | 0.713 | 2.469 | 2.965 | 3.461 |

*Table 85 SOx and PM2.5 Emissions Factors (lbs/MMBtu)*

| Unit Category | SO2 lbs/MMBtu | PM2.5 lbs/MMBtu |
|---|---|---|
| CC | 0.001 | 0.007 |
| CT | 0.001 | 0.007 |
| ICE | 0.001 | 0.010 |
| Cogen | 0.001 | 0.007 |
| Steam | 0.001 | 0.008 |
| Coal | 0.085 | 0.020 |

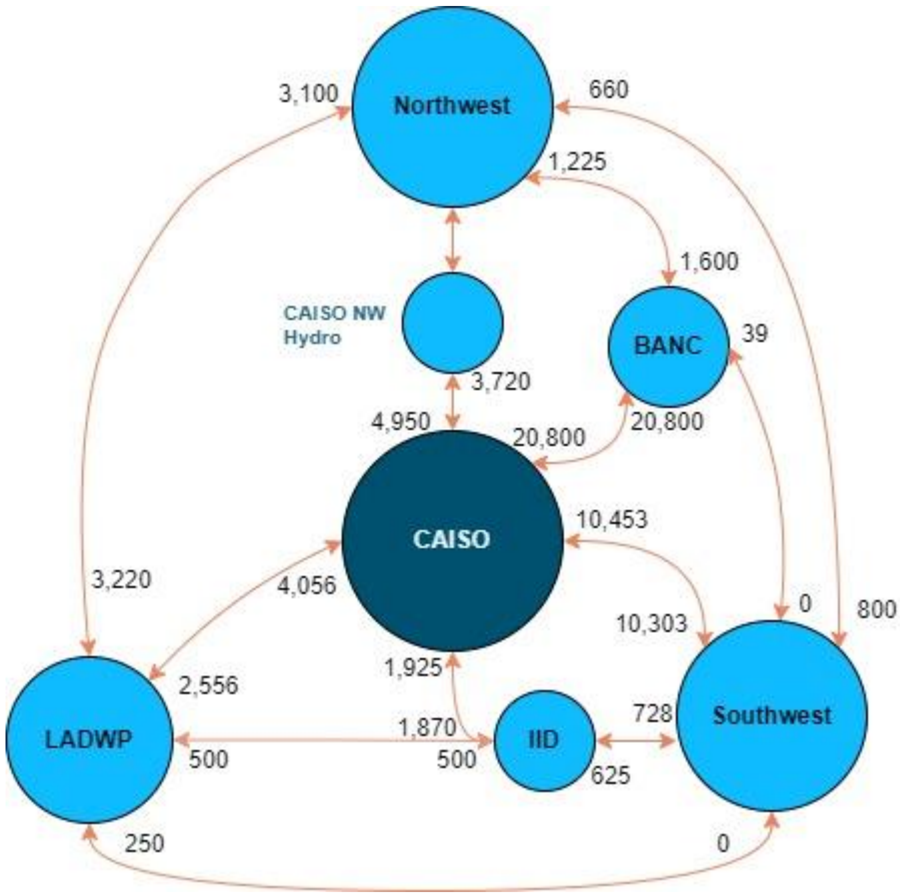
## 6.7 Transmission Topology

Transmission flow limits between RESOLVE BAAs are the sum of flow limits between individual BAAs in the CPUC's SERVM model.[148] SERVM flow limits were in-turn derived from the CAISO's

[148] 2019 Unified RA and IRP Modeling Datasets available at: https://www.cpuc.ca.gov/General.aspx?id=6442461894

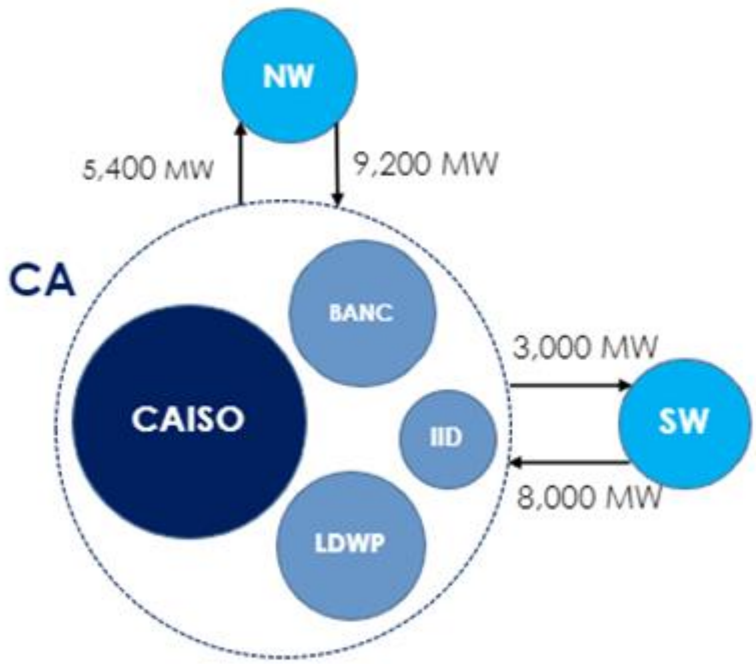
PLEXOS model and supplemented with information from the CEC's PLEXOS model. CAISO's PLEXOS production cost model uses nodal flow ratings from the WECC 2032 ADS 2.0 dataset and path limits from WECC Path Rating 2022 catalog. The CEC's PLEXOS model was used as a supplemental data source for paths that did not have enough geographic resolution in CAISO's dataset. The information in this section represents the interzonal transmission simultaneous flow limits, and is different from the transmission deliverability and interconnection data discussed in Sections 5.2 and 5.5.

*Figure 24. Transmission topology used in RESOLVE (transfer limits shown in MW)*




In addition to the physical underlying transmission topology, RESOLVE also includes constraints on simultaneous net imports into, and exports out of CAISO. The net export constraint is included to capture explicitly the uncertainty in the size of the future potential market for California's exports of surplus renewable power. The net import limit reflects the limit on simultaneous imports into CAISO, and accounts for resources that are external to CAISO but modeled within CAISO in RESOLVE. Those include the CAISO LSE share of Hoover, Intermountain Power Plant, Palo Verde, and Sutter, as well as additional remote firm (CCGT and geothermal) generators in other zones that are contracted to deliver energy to CAISO. This MW limit is taken from the total import capability of 11,040 MW from CAISO RA import capability reports.[149] The CAISO simultaneous export limit is set at 5,000 MW. The simultaneous net import/export limit applies to all hours of the year. The contribution of all import capacity to the CAISO PRM is set at 4,000 MW to reflect additional, non-modeled constraints on import availability during peak hours. In addition to CAISO, two other simultaneous flow constraints are added for California to and from SW and NW zones. These values are shown in Figure 25 below.

*Figure 25. Assumed California to NW and Southwest net export and net import limits.*




### 6.7.1 Hurdle Rates

RESOLVE incorporates hurdle rates for transfers between zones; these hurdle rates are intended to capture the transactional friction to trade energy across neighboring transmission systems. Hurdle rates in RESOLVE are tied to the zone of export and are derived from the hurdle rates used in the SERVM model. SERVM hurdle rates were in-turn derived from the CAISO's PLEXOS model and supplemented with information from the CEC's PLEXOS model. RESOLVE's NW and SW zones represent an aggregation of multiple BAAs, making it likely that the transmission systems of multiple BAAs would be used to export energy from these regions to CAISO. Consequently, hurdle rates to export from the NW and SW are calculated as the

[149] CAISO Import Allocations, "Step 6: Assigned and Unassigned RA Import Capability on Branch Groups." http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

capacity-weighted average export hurdle of the constituent BAAs, and in SERVM there is an additional hurdle for a zone adjacent to CAISO added: APS for the SW and BPA for the NW.

*Table 84. Hurdle Rates in RESOLVE ($2022/MWh)*

| Export Zone | Hurdle Rate ($/MWh) |
|---|---|
| From BANC | $ 2.95 |
| From CAISO | $ 12.70 |
| From IID | $ 3.87 |
| From LDWP | $ 6.81 |
| From NW | $ 11.35 |
| From SW | $ 13.87 |

In addition to cost-based hurdle rates, an additional cost from CARB's cap and trade program is added to unspecified imports into California; this cost is calculated based on the relevant year's carbon allowance cost and a deemed rate of 0.428 metric tons/MWh.[150] For carbon costs, the 2022-2023 IRP cycle assumptions include three options. Each option is based on CED 2022 Update GHG Allowance Price Projections.[151] RESOLVE only applies these carbon prices to resources in California, as well as unspecified imports into CAISO. The 2022-2023 IRP cycle inputs also include the option to run RESOLVE without a carbon price via the "Zero" trajectory. The "Low" trajectory is used by default which represents the price floor.

*Table 85. Carbon Cost Forecast Options (2022$/tonne $CO_2$$)*

| Fuel Type | 2025 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|
| Low | $24.39 | $31.46 | $40.47 | $52.11 | $67.43 |
| Mid | $37.97 | $60.80 | $97.06 | $162.78 | $273.43 |
| High | $40.23 | $70.94 | $124.72 | $200.86 | $324.01 |
| Zero | - | - | - | - | - |

[150] Based on CARB's rules for CARB's Mandatory Greenhouse Gas Reporting Regulation, available at: https://ww2.arb.ca.gov/mrr-regulation

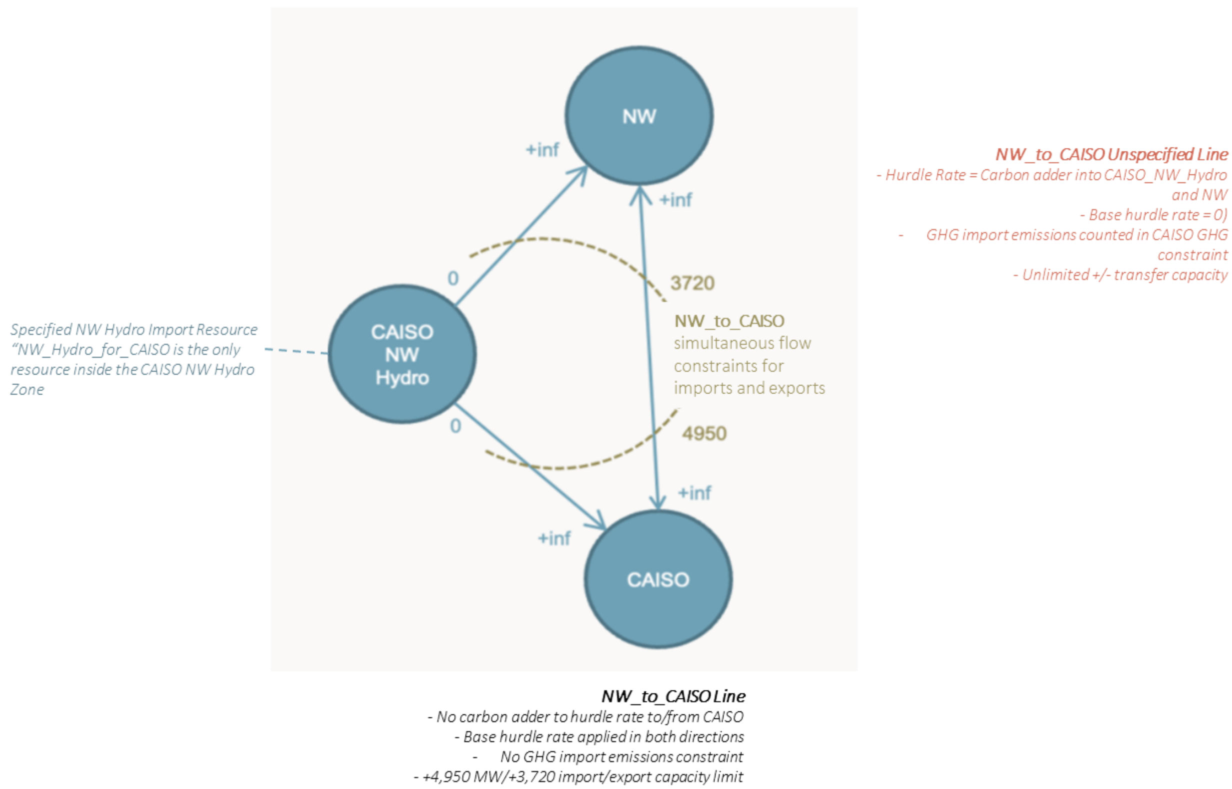
[151] Available at:
https://efiling.energy.ca.gov/GetDocument.aspx?tn=248410&DocumentContentId=82843

https://efiling.energy.ca.gov/GetDocument.aspx?tn=227328&DocumentContentId=58424

### 6.7.2 RESOLVE Transmission Topology for Specified Imports of NW Hydro

As shown in *Figure 26*, the 2022-2023 IRP cycle RESOLVE model continues to reflect specified hydro imports from the Pacific Northwest on an hourly basis. The resource **NW_Hydro_for_CAISO** is located in a new zone called **CAISO_NW_Hydro**. The CAISO_NW_Hydro zone is contained within the NW zone and does not have any load. CAISO can receive unspecified imports from the NW to CAISO and from the CAISO NW Hydro to CAISO, while exports can only go from CAISO to NW, excluding the CAISO NW Hydro zone. Emissions from unspecified imports from the NW are counted towards CAISO's GHG limit and incur CARB cap and trade emission permit costs using CARB GHG intensity for unspecified imports. Transfer limits into and out of CAISO are applied to both transfers to the NW zone and the CAISO_NW_Hydro zone. Essentially both NW_to_CAISO line and the CAISO_NW_Hydro line are subject to the simultaneous import and export limits between California and the Northwest.

*Figure 26. Transmission Topology of NW Hydro Imports in RESOLVE*



## 6.8 Fuel Costs

Monthly natural gas price inputs are derived from the preliminary 2023 IEPR burner tip price estimates from the CEC's North American Market Gas-trade (NAMGas) model runs.[152] SERVM simulates each region individually, and burner tip prices by hub are utilized directly. For RESOLVE, gas fuel prices for each zone are aggregated from NAMGas burner tip information using the average of selected hubs in each zone of interest. The 2023 vintage of natural gas price forecast has data through 2059 with three forecasts available, i.e., High Demand, Mid Demand, and Low Demand, corresponding to Low, Mid, and High natural gas prices, respectively.[153] Fuel transportation costs are also sourced from the 2023 NAMGas model. For PSP modeling, the mid scenario will be used as the default fuel costs. The fuel prices will be updated if the final version of this forecast differs from the preliminary forecasts. The gas price forecasts for the three scenarios are shown in Table 86. Coal and uranium prices are updated using the forecasted prices in the 2023 Annual Energy Outlook[154] using data in Table 3.9 for the Pacific zone and Table 3.8 for the Mountain zone (see Table 87.) It is notable that coal and nuclear power plants are currently not considered as candidate resources in IRP modeling. As such, coal and uranium fuel prices do not impact resource builds results. Further, nuclear power plants are currently modeled as a must-run resource;[155] therefore, uranium fuel prices do not impact nuclear generation dispatch results.

Biomass fuel costs of $15/MMBtu were taken as the median of the value range provided in an NREL Biomass technology report.[156]

For RESOLVE modeling needs, in addition to annual fuel price forecast, monthly price shapes are calculated from 2023 IEPR burner tip price estimates to capture seasonal variations in fuel prices which mainly impacts natural gas fuels. These shapes are shown in Table 88.

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[152] https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-electric-generation-prices-california-and

[153] Data can be accessed from https://www.eia.gov/outlooks/aeo/tables_ref.php.
154 Annual Energy Outlook 2023. https://www.eia.gov/outlooks/aeo/

[155] Nuclear power plants are characterized by high capital costs relative to fuel costs and are therefore, economically incentivized to run at high-capacity factors. This is likely true for more operationally flexible nuclear generator types (e.g., small modular reactors) as well based on existing cost data.
156 https://www.energy.gov/sites/default/files/2018/11/f57/robi-biomass.pdf

*Table 86. Natural Gas Fuel Price Forecast Scenario Options ($/MMBtu, 2022$)*

| Scenario | Region | 2025 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|
| 2023 IEPR – Low | California | 5.84 | 6.02 | 6.27 | 6.59 | 6.98 |
| | Northwest | 4.48 | 4.44 | 4.41 | 4.40 | 4.39 |
| | Southwest | 4.50 | 4.44 | 4.40 | 4.37 | 4.35 |
| 2023 IEPR – Mid | California | 6.35 | 6.56 | 6.82 | 7.13 | 7.52 |
| | Northwest | 4.90 | 4.87 | 4.85 | 4.84 | 4.84 |
| | Southwest | 5.00 | 4.97 | 4.93 | 4.96 | 4.97 |
| 2023 IEPR – High | California | 6.82 | 7.24 | 7.60 | 8.02 | 8.50 |
| | Northwest | 5.34 | 5.42 | 5.49 | 5.59 | 5.68 |
| | Southwest | 5.47 | 5.65 | 5.77 | 5.88 | 5.99 |

*Table 87. Coal, Uranium, and Biogas Fuel Price Forecasts ($/MMBtu, 2022$)*

| Fuel Type | 2025 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|
| California and NW Coal | 2.29 | 1.59 | 1.26 | 1.33 | 1.33 |
| SW Coal | 1.79 | 2.14 | 2.06 | 2.01 | 1.96 |
| Uranium | 0.71 | 0.71 | 0.71 | 0.71 | 0.71 |
| Biomass | 15.00 | 15.00 | 15.00 | 15.00 | 15.00 |

*Table 88. Monthly Price Shape as Percentage of Annual Price*

| Fuel Type | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural Gas – CA | 106% | 104% | 97% | 95% | 98% | 99% | 99% | 98% | 99% | 99% | 102% | 103% |
| Natural Gas – NW | 107% | 104% | 96% | 95% | 98% | 99% | 99% | 98% | 99% | 98% | 103% | 103% |
| Natural Gas – SW | 107% | 104% | 97% | 95% | 98% | 99% | 99% | 98% | 99% | 98% | 103% | 103% |
| Biomass | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Coal | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Uranium | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

# 7. Resource Adequacy Requirements

## 7.1 System Resource Adequacy

To ensure that the optimized resource portfolio is sufficient to meet resource adequacy[157] needs throughout the year, IRP planning models (both RESOLVE and SERVM) perform assessments to ensure that total available generation capacity (measured in effective load carrying capability, i.e., ELCC) plus available imports in each year meets or exceeds a reserve margin above the annual 1-in-2 gross peak demand. IRP modeling is designed to ensure that the CAISO system would not be expected to endure more than one loss of load event in ten years, satisfying the Commission's 1-day-in-10-year loss of load expectation (LOLE) reliability standard used in the IRP proceeding.

SERVM is utilized for resource adequacy and reliability studies. A study is performed to measure the amount of perfect capacity required to meet the 0.1 LOLE reliability standard in the CAISO system. The required level of perfect capacity (or perfect capacity equivalent) is a measure of the system's Total Reliability Need (TRN). Portfolios selected in RESOLVE's capacity expansion module are constrained to meet or exceed the TRN calculated in SERVM. RESOLVE calculates TRN endogenously via a comparison of median gross peak demand and an input PRM percentage based on the SERVM study.

### 7.1.1 Setting the Total Reliability Need and the Associated Planning Reserve Margins

The TRN is the total effective capacity needed to reach a system's probabilistic reliability standard. Historically, via the Resource Adequacy program and prior IRP cycles, the CPUC has used installed capacity (ICAP) based accreditation methods, which count firm capacity resources (gas, nuclear, etc.) at their installed capacity and count non-firm resources (hydro, solar, wind, etc.) using either heuristics or their ELCC. This method does not explicitly quantify the impact of firm plant forced outages in the reliability need determination, indirectly increasing the reserve margin required to account for the risk of those outages. However, this can create an un-level playing field between resources, whereby thermal resources are accredited at a value higher than their actual reliability contribution (i.e., their ELCC), while non-firm resources – including new carbon-reducing resources – are accredited at their ELCC.

Two key improvements were made for this IRP cycle:

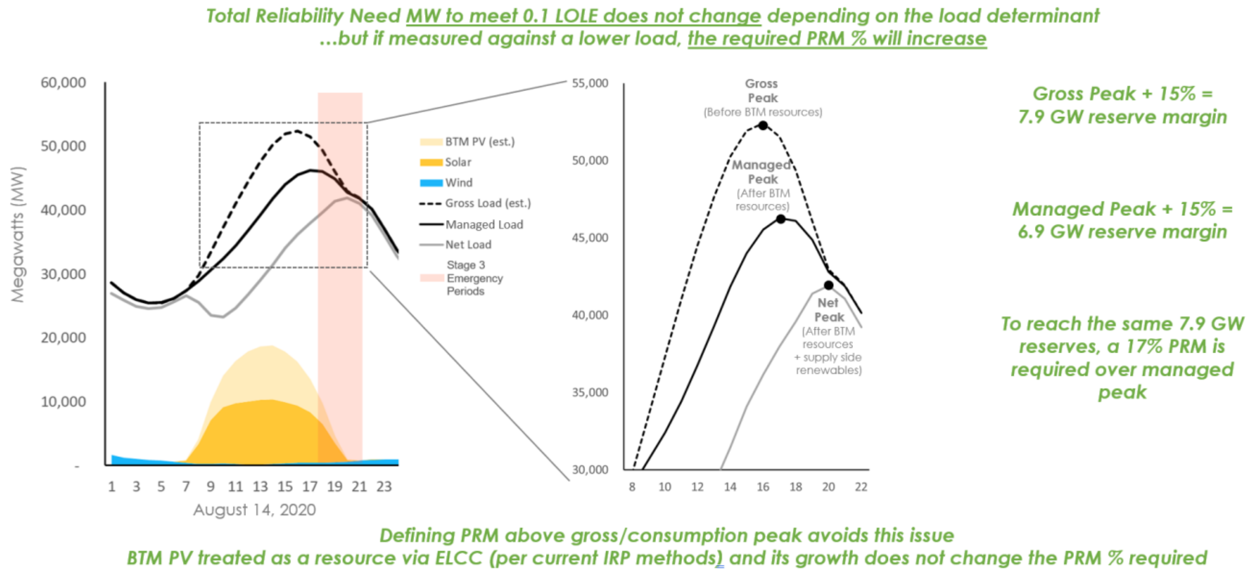
[157] Resource adequacy is referred to here in a broad sense, rather than with specific reference to the CPUC RA program.

First, the planning reserve margin is now calculated from the total reliability need, as derived from SERVM model simulations using the most recent data.[158] Staff believes this is an improvement over the PRM values used in past IRP cycles because it is tied to the fundamental weather, load, and operating reserve drivers that create reliability risk in SERVM's loss of load probability modeling, using the most recent data available on past historical weather conditions. While past cycles have used a PRM higher than 15%, this is the first cycle to directly use a "target PRM" derived from SERVM analysis consistent with the 1-day-in-10-year LOLE standard.

Second, the reliability need definition is now defined in total ELCC MW, i.e., total perfect capacity equivalent MW, using "PCAP" accounting instead of the ICAP accounting used in previous cycles. This puts all resources on a level playing field within RESOLVE's economic optimization as it requires that all resources are counted at their ELCC. It also provides a more durable reliability need determination across the planning horizon, because the PCAP total reliability need (and therefore the PCAP PRM) is not dependent on the resource portfolio, but instead on load shapes, load variability, and operating reserve requirements. This PCAP PRM is lower than the ICAP PRM used in previous IRP cycles, because no resources are accredited higher than their PCAP equivalent. The PCAP PRM is measured above the gross system peak, i.e., the IEPR managed peak before BTM PV peak reduction. A PRM measured at the gross (higher) peak is a lower percentage than a PRM measured at the managed (lower) peak because the same total reliability need MW can be obtained with a lower percentage margin when multiplied by a higher (gross) peak.

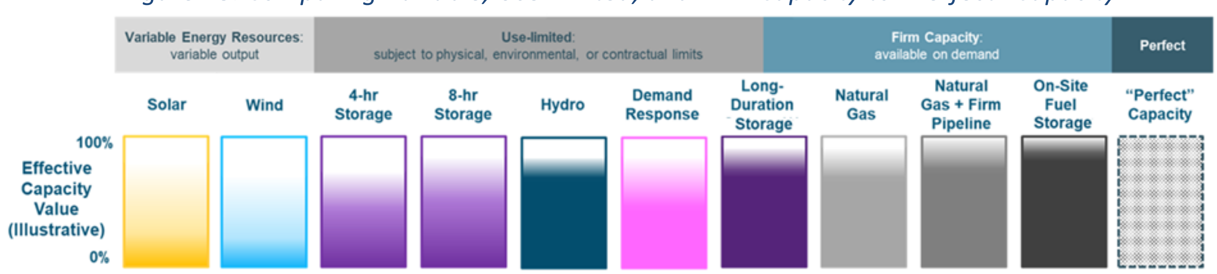
[158] RESOLVE originally used a 15% ICAP PRM, based on modeling in the early-mid 2000's that led to the 15% PRM assumption used for many years in LTPP and the RA program. In the 2019-2021 IRP cycle, RESOLVE used an adder above 15% to account for calibration with SERVM results and then used a 22.5% ICAP PRM to reflect the assumptions used in the MTR procurement order. The most recent RESOLVE runs (i.e., the 23-24 TPP) used a PCAP PRM consistent with the current methodology, albeit an earlier PCAP PRM calculations based on the 2021 IEPR.

*Figure 27. Gross vs. Managed vs. Net Peak and the impact on PRM %*




A “perfect capacity” generator is a theoretical concept, representing a firm generator that has no outages, fuel constraints, or other availability limitations. Since no resource provides perfect capacity, as shown in Figure 28, the perfect capacity concept is simply a useful metric for which to measure all resources on a level playing field. ELCC studies are performed to calculate the perfect capacity equivalent MW, i.e., the ELCC for each resource.

*Figure 28. Comparing Variable, Use-limited, and Firm Capacity to “Perfect” Capacity*




The TRN measures the necessary accredited capacity to meet a target reliability standard. When all resources are counted at their ELCC, the total reliability need for the CAISO system can be expressed as the total ELCC MW required to maintain a 0.1 days/year loss of load expectation reliability standard. For example, the results of the most recent SERVM simulations on the 2026 CAISO system are shown in Figure 29 below; these were updated in 2023 to use the 2022 IEPR load forecast.[159] They indicate that, in 2026, 61.7 ELCC GW are necessary to

[159] See the July 2022 IRP MAG webinar for details of the PRM study design and prior results. Results shown here are updated using the 2022 IEPR. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-

achieve the 0.1 days/yr standard. Relative to the IEPR gross peak of 54.9 GW, this is equivalent to a ~12.5% PCAP planning reserve margin above the median gross peak. For the reasons described earlier, this percentage is lower than an ICAP PRM above median managed peak for two reasons: firstly, PCAP accounting shifts the allowance for forced outages of firm resources from the reliability need (i.e., within the PRM) to their ELCC used for resource counting, and secondly, because the gross peak is higher than the managed peak, requiring a lower % reserve margin to reach the same level of MW. The translation of TRN MW to a PRM is shown in Figure 30. TRN simulations were performed in SERVM for 2026, 2030, and 2035, with differences in load shape components (e.g., growth of electric vehicles) impacting the required planning reserve margin.

In 2022, SERVM calculated the PRM using the 2021 IEPR load forecast, with the SERVM peak load across simulations tuned to the IEPR's gross peak (the hourly IEPR managed peak plus the BTM PV generation). This resulted in a PCAP PRM that was quite stable over the planning horizon, ranging from 13.5-14% above the IEPR's gross peak demand. In this cycle, staff updated the calculation to use the 2022 IEPR forecast, and this load forecast was tuned to the IEPR's managed peak (the hourly IEPR managed peak, which includes both the BTM PV generation peak reduction and the other demand side adjustments). These updates resulted in a lower or higher (depending on the year) CAISO PRM relative to the previously calculated ~14% value, with more year-to-year variance driven by the difference in each year between the IEPR's single year hourly BTM PV peak shift and the SERVM implied BTM PV peak shift over 23 weather years. The updated 2022 IEPR based PCAP PRM is 12.5% in 2026, 15.8% in 2030, and 15.6% in 2035. Values in between years were interpolated and the 2035 PRM was maintained in future years. In future IRP cycles, if SERVM simulations are tuned to the gross peak, staff expect to see a more stable PRM across modeled years.

Calibration to the IEPR Managed System Peak was done in order to facilitate Resource Adequacy program studies which base RA requirements on reserves in excess of the IEPR Managed Peak. RA requirements do not explicitly give credit to BTM PV or other demand side modifiers for meeting RA requirements, thus requirements need to be shown exclusive of demand side modifiers. Since IRP includes an ELCC surface that counts BTM PV reliability contributions, it defines the PRM above the gross peak and counts the ELCC from BTM PV.

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division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/20220729-updated-fr-and-reliability-mag-slides.pdf

*Figure 29. SERVM Total Reliability Need (TRN) Simulation Results (2026)*

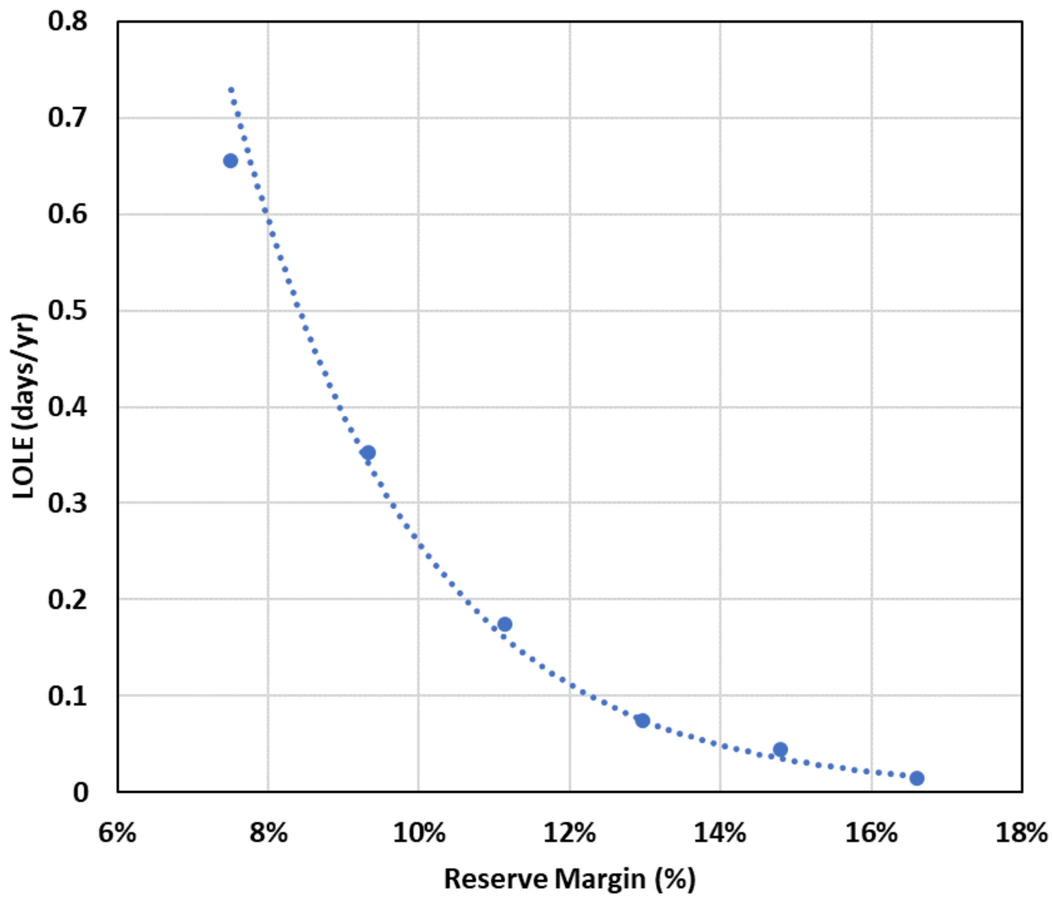
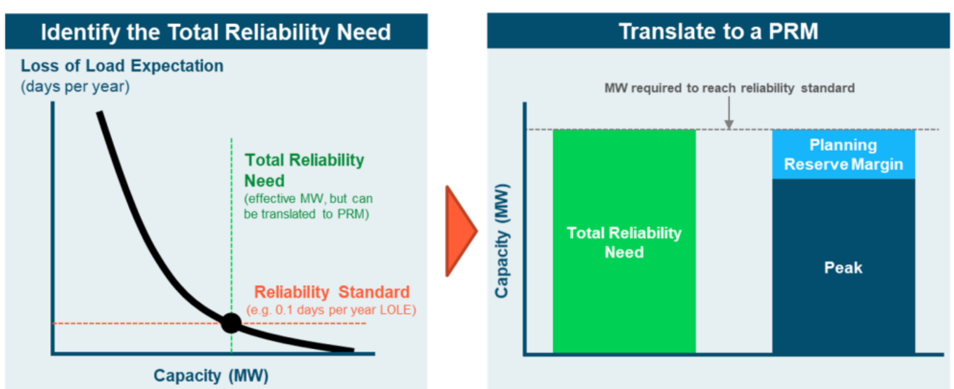



*Figure 30. Translating Total Reliability Need MW into a Planning Reserve Margin Percentage*



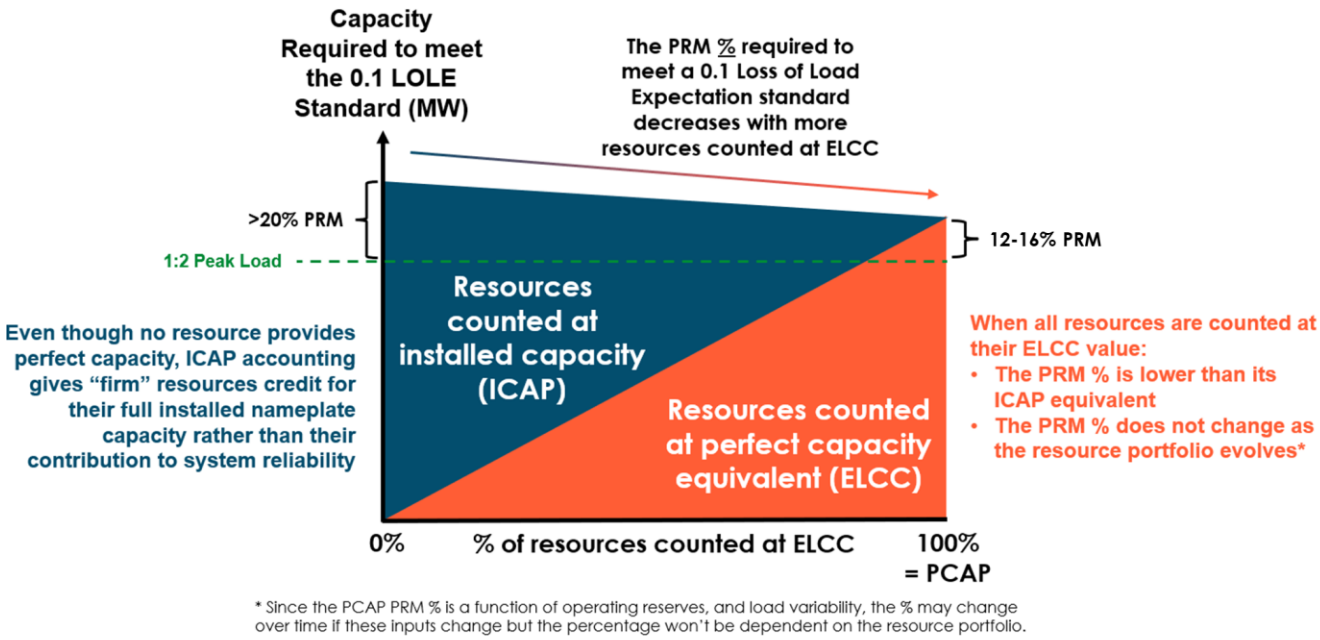

***Total Reliability Need =***
*Total effective capacity (in MW) needed to maintain an adopted reliability standard* (e.g., < 0.1 day/yr LOLE)

***Planning Reserve Margin =***
*% margin above peak demand necessary to reach the TRN*

$$PRM\ \% = \left(\frac{TRN}{Peak\ Demand}\right) - 1$$

A PCAP PRM cannot be compared to a single ICAP PRM data point, because the ICAP PRM is inherently dependent on the resource portfolio, whereas the PCAP PRM is not. Figure 31 **Error! Reference source not found.**shows an indicative visual representation of how the ICAP PRM declines as the share of resources counted at their ELCC increases, until the share counted at their ELCC becomes 100%, which is the PCAP PRM.

*Figure 31. How an ICAP PRM Percentage Decreases with Higher Shares of ELCC Resources*




For example, a 14% PCAP PRM is approximately equivalent to an ~18% ICAP PRM with 55% of the TRN measured in ELCC MW or a ~21.5% ICAP PRM with 30% of the TRN measured in ELCC MW. These values are measured above the gross peak. When measured above the managed peak with 30% of the TRN measured in ELCC MW, the required ICAP PRM is ~23.5%.

The PCAP PRM study can be repeated each IRP cycle to update RESOLVE's reliability need, incorporating the latest IEPR load shapes as well as additional more recent weather years into SERVM simulations. These may cause minor updates to the total reliability need, for instance, when additional years of historical weather conditions are added to SERVM or if climate impacts are incorporated to adjust the SERVM weather dataset.

To ensure resource capacity counting is aligned with a PCAP PRM, all resources must be counted at their ELCC value. As discussed below, the contribution of each resource to the total reliability need requirement depends on its performance characteristics, the availability to produce power during the most constrained periods of the year, and interactive effects with other resources. The sections below describe the resulting ELCCs.

### 7.1.2 Adjusting Total Reliability Need to Reflect CPUC Procurement Orders

To ensure the RESOLVE portfolio reflects the procurement ordered by recent Commission IRP Mid-Term Reliability (MTR) procurement orders (D.21-06-035 and D.23-02-040), a modification is made to RESOLVE's reliability need. An adjustment to reliability constraints is necessary to ensure RESOLVE builds enough new capacity to meet the cumulative 15.5 GW NQC from the MTR orders.

The total ELCC MW from the cumulative MTR order amounts is calculated as a minimum total ELCC MW of new zero-emission resources RESOLVE must cumulatively build in each respective year. Additionally, RESOLVE must comply with the 2028 MTR requirement for Long Lead-Time resources for 1 GW of firm zero-carbon resources and 1 GW of long duration storage (8-hour duration or greater). Resources are counted toward this requirement based on ELCCs calculated by the MTR Incremental ELCC Study.[160] For resource types not addressed by the Study, RA program NQCs are used. For years in which the total MTR ELCC MW requirement is higher than the PCAP PRM requirement, RESOLVE will build additional capacity to comply with the MTR procurement order.

### 7.1.3 Approach to Calculating Resource ELCCs

With all resources counted at their ELCC, an approach was necessary to account for interactive effects amongst resources. This requires calculating each resource type's ELCCs in a sequence so that the interactive effects between different resource types present on the system are properly accounted for and not over-counted. For instance, if all resources were studied via their "last-in" ELCC, i.e., wherein each resource's ELCC is calculated in the presence of all other resources in the portfolio, then the interactive effects of the portfolio would be counted in each resource's ELCC, and hence the true interactive effects of the portfolio would be over-counted when summing the ELCCs of all resources in RESOLVE. Instead of treating all resources as "first-in" or "last-in", resource ELCCs were calculated in sequence (first-in, second-in, third-in, etc.) starting with existing resources and then moving on to candidate resource options. The following approach was taken:

+ Existing firm[161] resource ELCCs were developed as "first-in" ELCCs for the firm resource fleet

[160] 20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf (ca.gov)

[161] "Firm" resources are those that can generally operate on demand without any significant use limitations, though they are still subject to unplanned forced outages.

- Candidate biomass and geothermal resources receive the “first-in” ELCCs derived from the existing firm resource fleet
- Existing hydro ELCCs were calculated as “second-in” ELCCs
- Existing pumped hydro storage ELCCs were calculated as “third-in” ELCCs
- Existing demand response resources were calculated as “fourth-in” ELCCs
- Solar, battery storage, and wind resources, as well as other candidate resource options, were then calculated on top of the existing resource fleet
    - Wind ELCCs were calculated as three stand-alone curves for in-state, out-of-state, and offshore wind using the 2030 portfolio from the 38 MMT 2021 PSP portfolio (updated with the 2021 IEPR), including the level of solar and storage selected
    - Solar and 4-hour duration battery storage ELCCs were calculated as a two-dimensional ELCC “surface” to capture interactive effects between the two resources, using the 2030 portfolio from the 38 MMT 2021 PSP portfolio (updated with the 2021 IEPR), including the level of wind selected
    - Candidate demand response resources are accounted for on the storage dimension of the solar + storage surface; the nameplate capacities of demand response resources are derated when being counted on the surface to reflect their reliability value relative to 4-hour battery storage
    - Candidate pumped hydro storage and long-duration storage resources are accounted for on the storage dimension of the solar + storage surface; the nameplate capacities of these resources are increased by a scalar multiplier when counted on the surface to reflect the increased reliability value of longer duration storage resources relative to 4-hour storage

By sequencing the ELCC calculations in this way, interactive effects between the existing resources and new resources (e.g., between existing DR and new battery storage) are allocated to the new candidate resources. This is appropriate for RESOLVE, since nearly all the existing resources remain throughout the planning horizon, while RESOLVE makes economically optimal decisions for adding candidate resources using their marginal incremental capacity value on top of the existing resource fleet.

Figure 32 below summarizes the new methods for capacity contributions compared to those used in the last IRP cycle.

*Figure 32. Reliability Planning Changes for the 2022-2023 IRP Cycle*

| | Prior Approach: 2021 Preferred System Plan (PSP) | Current Approach: 2022-23 IRP Cycle |
|---|---|---|
| **Planning Reserve Margin** | **22.5% installed capacity based (ICAP)** PRM above managed peak | **~12-16% perfect capacity based (PCAP)** PRM over gross peak |
| **Wind** | ELCC (solar/wind ELCC surface) | ELCC (in-state, OOS, offshore wind curves) |
| **Solar PV** | | ELCC (solar/storage surface) |
| **BTM PV** | ELCC (solar/wind ELCC surface), after increasing need by IEPR peak shift | |
| **Battery Storage** | ELCC curve (Battery only) | |
| **Long Duration Storage** | Installed capacity (NQC) | ELCC (model new long duration storage on storage dimension of solar/storage surface, w/ up-rate multiplier) |
| **Demand Response (Load Shed)** | DR program capacity (NQC) for new + existing | ELCC (model new DR on storage dimension of solar/storage surface, w/ de-rate multiplier) |
| **Hydro** | Installed capacity (NQC) | ELCC |
| **Bio/Geo/Nuclear** | | |
| **Fossil (CT/peaker, CCGT, CHP, coal)** | | |
| **BTM Storage** | Load modifier via IEPR assumptions | Load modifier via IEPR assumptions |

Note that all resources are now counted at ELCC except for BTM storage. This resource is modeled as a load modifier based on the IEPR's hourly charging and discharging shapes. This is because the IEPR's shapes generally show low capacity value for the BTM storage discharge, hence modeling it as a supply side battery resource would overstate its value relative to the IEPR. Future IRP cycles will continue to review IEPR BTM storage shapes and consider whether and how to incorporate BTM storage value as a resource counted at ELCC (such as using a de-rate factor relative to other battery storage). The ELCC values of all modeled resources can be found in the "*PRM and MTR*" tab of the RESOLVE Scenario Tool

### 7.1.4 Firm Resource Contributions (Gas, CHP, Coal, Nuclear, Biomass/gas, Geothermal)

The contribution of firm capacity resources was developed by calculating in SERVM the "first-in" ELCC of the entire firm resource fleet: gas, CHP, coal, nuclear, biomass/gas, and geothermal resources. This was done using 2030 CAISO loads and resources. This firm fleet ELCC MW was then allocated across each firm fleet resource category based on the relative EFORd[162] outage rates. In unforced capacity (UCAP) accounting used in some eastern RTO resource adequacy programs, UCAP MW is based on nameplate capacity * (1 – EFORd). However, the ELCC de-rate is higher than the EFORd value, because the EFORd value is an average outage rate value whereas in LOLP modeling a distribution of outages for the firm fleet are considered in a Monte

[162] Equivalent Forced Outage Rate demand (EFORd) is a SERVM output characterizing class average forced outage rates during operating hours using generator performance data.

Carlo simulation. During some periods at the tails of these distributions, many units are simultaneously on full outage. These simultaneous outages simulated in LOLP modeling can create loss of load events, hence they reduce the ELCC of the firm fleet relative to its UCAP value based only on an EFORd derate. This can be considered an "outage asymmetry" effect, because the tail of the distribution with more outages has a higher impact on increasing LOLE than the tail of the distribution with few outages has on decreasing LOLE. Figure 33 below shows a schematic of how a PCAP/ELCC accounting approach captures the full "generator performance impact" that includes both the EFORd and the outage asymmetry impact. For now, this example does not illustrate the effect of ambient derates related to extreme heat events.

*Figure 33. Firm Resource Outage Treatment in ICAP, UCAP, and PCAP PRM Accounting*

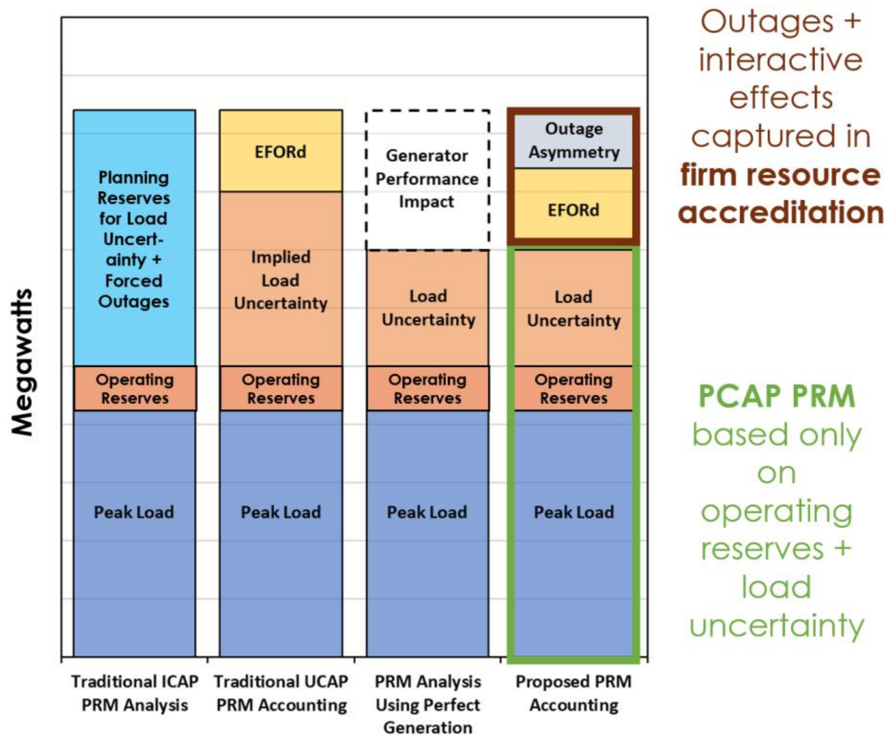



Figure 34 below shows the EFORd values[163] for each firm resource sub-class, the UCAP values, and the ELCC values that result when scaling up the EFORd de-rate so that the total firm fleet de-rate is equivalent to the ELCC MW calculated in SERVM.

[163] These are sourced from SERVM simulations based on the forced outage rate input data developed for SERVM from the NERC GADS database.

*Figure 34. Firm Resource Outage Rates and ELCCs*

1. Portfolio ELCC of all "firm" resources was calculated in SERVM
2. Firm resource portfolio ELCC allocated between resource classes using capacity-weighted forced outage rate (EFORd from SERVM analysis)
3. Due to portfolio interactive effects, especially the dynamic that loss of load events happen more frequently during simultaneous outages, this results in a lower ELCC than the Unforced (UCAP) %

| Resource Class | 1-EFORd: Equivalent Forced Outage Rate demand (%) | UCAP =1-EFORd (% of nameplate) | > | ELCC for RESOLVE (% of nameplate) |
|---|---|---|---|---|
| Combined Cycle | 5.5% | 94.5% | | 88.3% |
| Combustion Turbine | 6.2% | 93.8% | | 87.0% |
| Reciprocating Engine | 4.2% | 95.8% | | 91.2% |
| Steam | 7.2% | 92.8% | | 84.8% |
| Combined Heat and Power (CHP) | 3.1% | 96.9% | | 93.5% |
| Nuclear | 2.0% | 98% | | 95.9% |
| Biomass and Biogas | 5.7% (biomass)<br>7.6% (biogas) | 94.3% (biomass)<br>92.4% (biogas) | | 86.7% |
| Geothermal | 2.6% | 97.4% | | 94.5% |

An additional adjustment was made for CHP, biomass/biogas, and geothermal resources. In the RA program[164], these resources are accredited based on historical analyses of resource availability and/or bid behavior. This results in a lower RA-program accredited NQC MW than the SERVM ELCC MW calculated for those resources. Therefore, in RESOLVE and SERVM, the nameplate MW was set as equal to the NQC MW so that the capacity of these resources reflects their availability-based accreditation in the RA program.

### 7.1.5 Hydro

The ELCC of hydroelectric resources is based on SERVM's "second-in" ELCC calculation. The full ELCC of both large and small CAISO hydro in 2030 was 4,300 MW, for an ELCC of 65%. In previous cycles, this was allocated to small and large hydro separately, as large hydro had a higher ELCC due to its storage capacity. In this cycle, large and small hydro are modeled in aggregate, thus this allocation was not necessary.

### 7.1.6 Existing Pumped Hydro Storage

Existing pumped hydro storage was calculated as the "third-in" ELCC after the firm fleet and hydro. This calculation in SERVM resulted in a 95% ELCC.

[164] The values shown here are based on the CPUC's 2022 NQC list.

### 7.1.7 Existing Demand Response

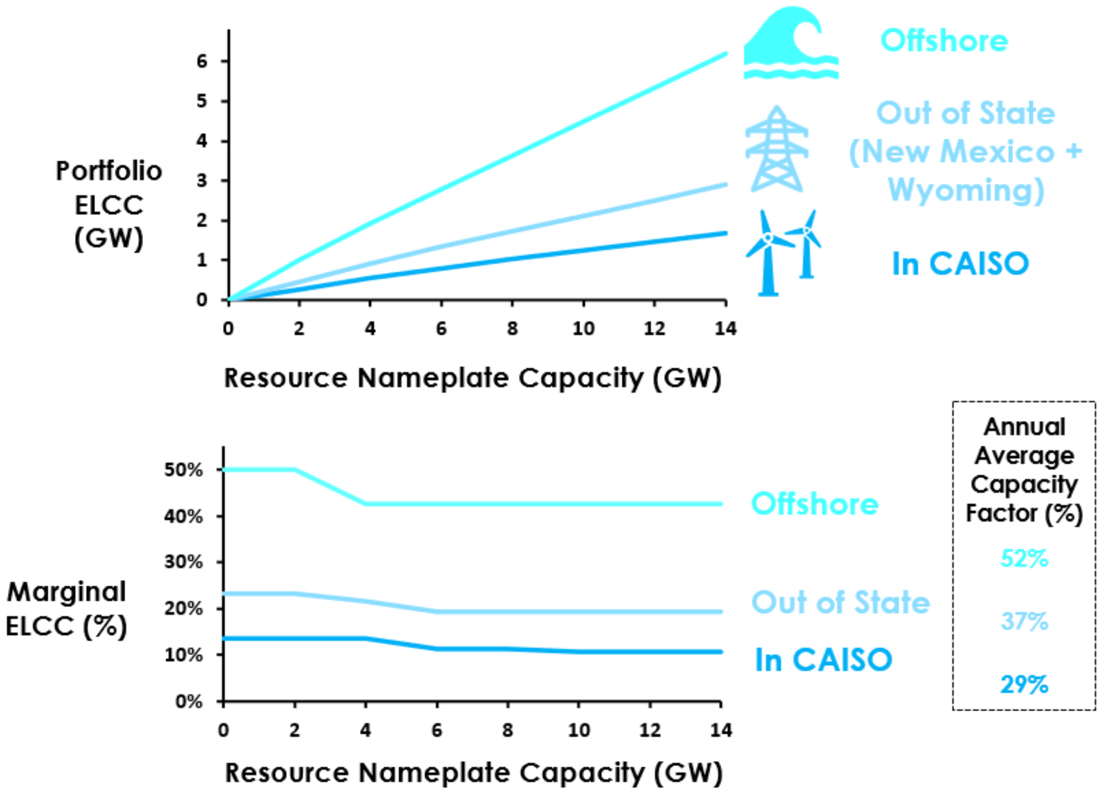
Existing demand response was calculated as the "fourth-in" ELCC after the firm fleet, hydro, and pumped hydro storage. This calculation in SERVM resulted in a 96% ELCC. This value is relatively high and kept constant since RESOLVE currently does not consider retirement of existing DR resources. New DR is accredited differently, as described below.

### 7.1.8 Wind

Renewable resources with FCDS status (Section 3.2.1) are assumed to contribute to system resource adequacy requirements.

Wind ELCCs are calculated in SERVM as three separate one-dimensional penetration curves for in-state, out-of-state, and offshore wind. This was done for two reasons. First, wind ELCCs increase as the net load is pushed further into the evening by solar, but most of this effect has already occurred by 2022-2024. Therefore, a one-dimensional wind curve is sufficient to capture this interactive effect, when that curve is calculated on top of the 2030 updated PSP portfolio that has significant solar and storage growth in it. Second, E3 and Astrapé tested the correlations between in-state, out-of-state, and offshore wind and found that they were sufficiently uncorrelated to warrant separate penetration curves. Hence, three different curves were developed as shown in Figure 35 below.

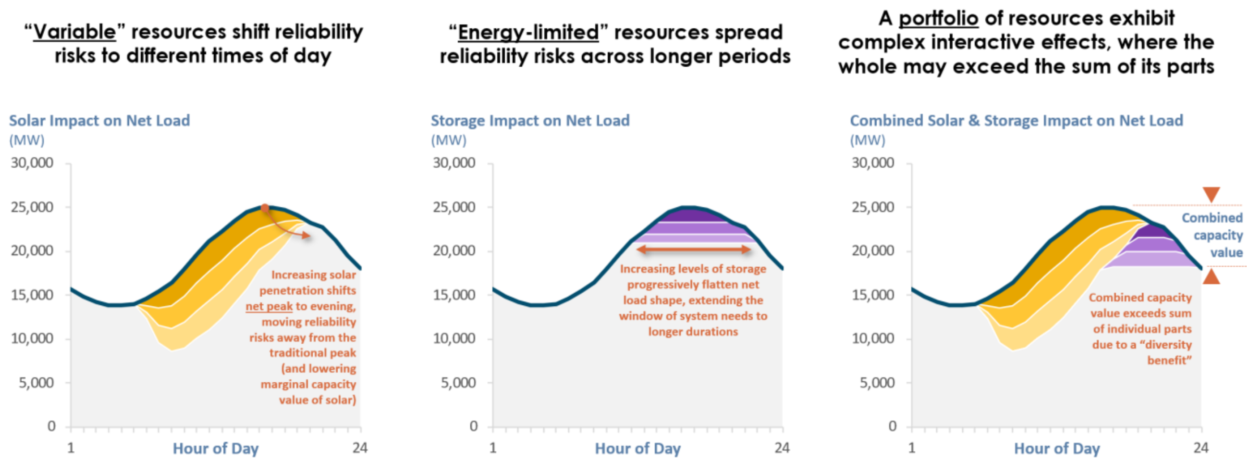
*Figure 35. Wind ELCC Curves*




### 7.1.9 Solar and Battery Storage

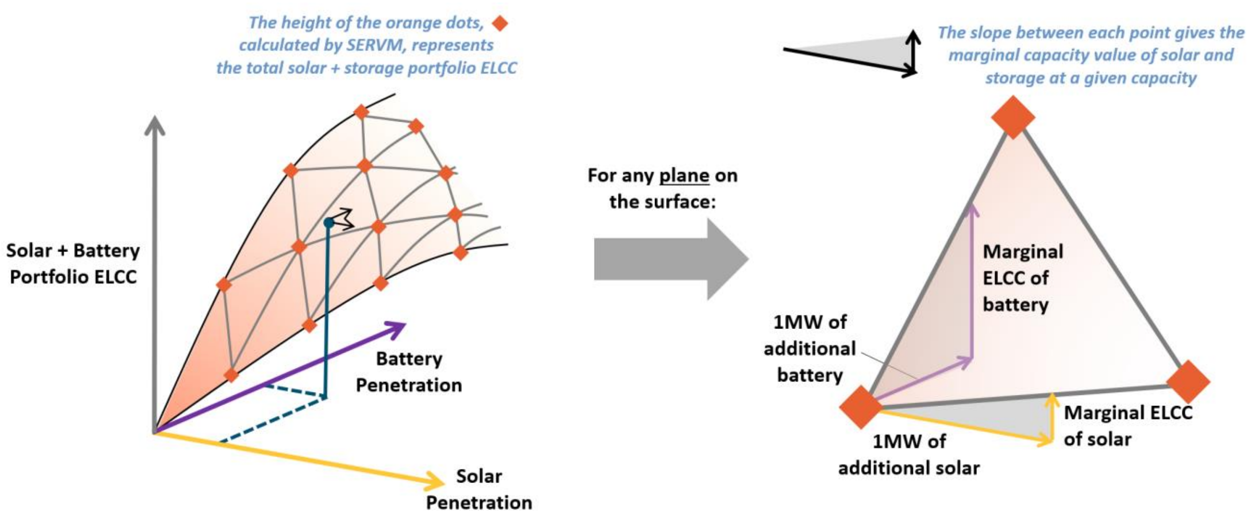
For this IRP cycle, the wind and solar two-dimensional ELCC surface is replaced by a solar and 4-hr battery storage ELCC surface. This change recognizes that, going forward for the CAISO, solar and battery storage resources have the most important interactive effects that should be captured in long-term capacity expansion studies. This synergistic interactive effect is illustrated in Figure 36 below. Solar and battery storage additions to the CAISO are very large in past RESOLVE studies. Solar shifts and narrows the net peak into the evening hours and provides mid-day charging energy for new batteries. Batteries shift and extend the net peak back into the mid-day solar hours.

*Figure 36. Solar and Storage Interactive Effects (illustrative)*




To capture these interactive effects, an ELCC surface was generated using SERVM ELCC studies that analyzed the portfolio ELCC of various levels of solar and battery storage additions on top of the 2030 updated PSP portfolio. A schematic of the surface is shown in Figure 37 below. Solar penetration is one dimension, 4-hr battery storage penetration is another dimension, and the combined portfolio ELCC is the third dimension of the surface. Since the entire surface cannot practically be mapped, specific points are sampled and the marginal ELCC between the points is calculated, as shown on the right side of the figure.

*Figure 37. Solar and Storage ELCC Surface Schematic*




Each facet i on the surface is a multivariate linear equation of the form $f_i(PV,STR) = a_iPV + b_iSTR + c_i$, where $f_i(PV,STR)$ is the total ELCC MW provided by solar and battery storage and PV and STR represent the MW capacity of solar and battery storage, respectively. Because of the declining marginal ELCC of solar and battery storage (and the corresponding convexity of this surface), the cumulative ELCC for any penetration of solar and battery storage can be evaluated as the minimum of all linear equations: $F(PV,STR) = \min[f_i(PV,STR)]$.

Figure 38 and Figure 39 below shows the marginal ELCCs of solar and storage on the ELCC surface at various penetrations of solar and storage MW in 2030.[165] At ~30 GW of solar penetration (combined utility scale and BTM PV), solar has low incremental value when battery storage is low (e.g. ~3-8% ELCC going from 30 to 40 GW of solar). However, when battery storage is added, the incremental solar ELCC rises as mid-day solar energy becomes increasingly important for ensuring batteries remain sufficiently charged to address the evening net peak.

*Figure 38. Incremental Solar ELCC % across the ELCC Surface*

**Calculated Incremental Solar ELCC %**

**Solar Nameplate Capacity (GW)**

| 4-Hour Battery Namplate Capacity (GW) | 30 | 35 | 40 | 45 | 50 | 55 | 60 | 65 | 70 | 75 | 80 | 85 | 90 | 95 | 100 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 5% | 3% | 3% | 3% | 3% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 5 | 6% | 3% | 3% | 3% | 3% | 3% | 3% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| 10 | 6% | 5% | 3% | 3% | 3% | 3% | 3% | 3% | 3% | 2% | 2% | 2% | 2% | 2% | 2% |
| 15 | 13% | 8% | 8% | 4% | 3% | 3% | 3% | 3% | 3% | 3% | 3% | 2% | 2% | 2% | 2% |
| 20 | 25% | 25% | 21% | 9% | 6% | 4% | 4% | 4% | 4% | 4% | 3% | 3% | 3% | 3% | 2% |
| 25 | 25% | 21% | 21% | 21% | 16% | 9% | 8% | 4% | 4% | 4% | 4% | 4% | 1% | 1% | 1% |
| 30 | 25% | 21% | 21% | 21% | 19% | 19% | 10% | 9% | 4% | 1% | 1% | 1% | 1% | 1% | 1% |
| 35 | 25% | 21% | 21% | 21% | 19% | 19% | 17% | 14% | 10% | 4% | 1% | 1% | 1% | 1% | 1% |
| 40 | 25% | 21% | 21% | 21% | 19% | 19% | 17% | 14% | 14% | 14% | 14% | 4% | 1% | 1% | 1% |
| 45 | 25% | 21% | 21% | 21% | 19% | 19% | 17% | 17% | 14% | 14% | 14% | 14% | 14% | 1% | 1% |
| 50 | 25% | 21% | 21% | 21% | 19% | 19% | 17% | 17% | 17% | 14% | 14% | 14% | 14% | 14% | 14% |

At low penetration, incremental battery storage ELCCs remain high and are not sensitive to the level of solar on the system. However, after adding ~10-20 GW of battery storage to the system, the net peak extends its duration such that 4-hr battery resources have insufficient energy to discharge, reducing their incremental value. Incremental batteries may also struggle to charge as the net load during the charging hours has increased such that there may be insufficient charging energy. At this point, the ability for battery storage to provide significant additional ELCC depends on adding solar together with batteries. RESOLVE will now consider these dynamics endogenously in its portfolio optimization.

[165] The surface is scaled with the peak load of the system to account for the impact of load growth on capacity value saturation.

*Figure 39. Incremental Battery Storage ELCC % across the ELCC Surface*

**Calculated Incremental Storage ELCC %**

**Solar Nameplate Capacity (GW)**

| 4-Hour Battery Namplate Capacity (GW) | 30 | 35 | 40 | 45 | 50 | 55 | 60 | 65 | 70 | 75 | 80 | 85 | 90 | 95 | 100 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 90% | 92% | 92% | 92% | 92% | 95% | 95% | 95% | 95% | 95% | 95% | 95% | 95% | 95% | 95% |
| 5 | 90% | 92% | 92% | 92% | 92% | 92% | 92% | 95% | 95% | 95% | 95% | 95% | 95% | 95% | 95% |
| 10 | 90% | 90% | 92% | 92% | 92% | 92% | 92% | 92% | 92% | 95% | 95% | 95% | 95% | 95% | 95% |
| 15 | 70% | 79% | 79% | 87% | 90% | 90% | 91% | 92% | 92% | 92% | 92% | 95% | 95% | 95% | 95% |
| 20 | 33% | 33% | 33% | 65% | 70% | 75% | 81% | 84% | 84% | 84% | 90% | 90% | 92% | 92% | 95% |
| 25 | 33% | 33% | 33% | 33% | 37% | 44% | 45% | 52% | 52% | 52% | 52% | 52% | 52% | 52% | 52% |
| 30 | 27% | 27% | 27% | 27% | 27% | 27% | 28% | 30% | 32% | 36% | 36% | 36% | 36% | 36% | 36% |
| 35 | 17% | 17% | 17% | 17% | 17% | 17% | 17% | 17% | 28% | 32% | 36% | 36% | 36% | 36% | 36% |
| 40 | 9% | 9% | 9% | 9% | 9% | 9% | 9% | 11% | 11% | 12% | 12% | 32% | 36% | 36% | 36% |
| 45 | 9% | 9% | 9% | 9% | 9% | 9% | 9% | 9% | 11% | 11% | 11% | 11% | 12% | 36% | 36% |
| 50 | 9% | 9% | 9% | 9% | 9% | 9% | 9% | 9% | 9% | 11% | 11% | 11% | 11% | 11% | 12% |

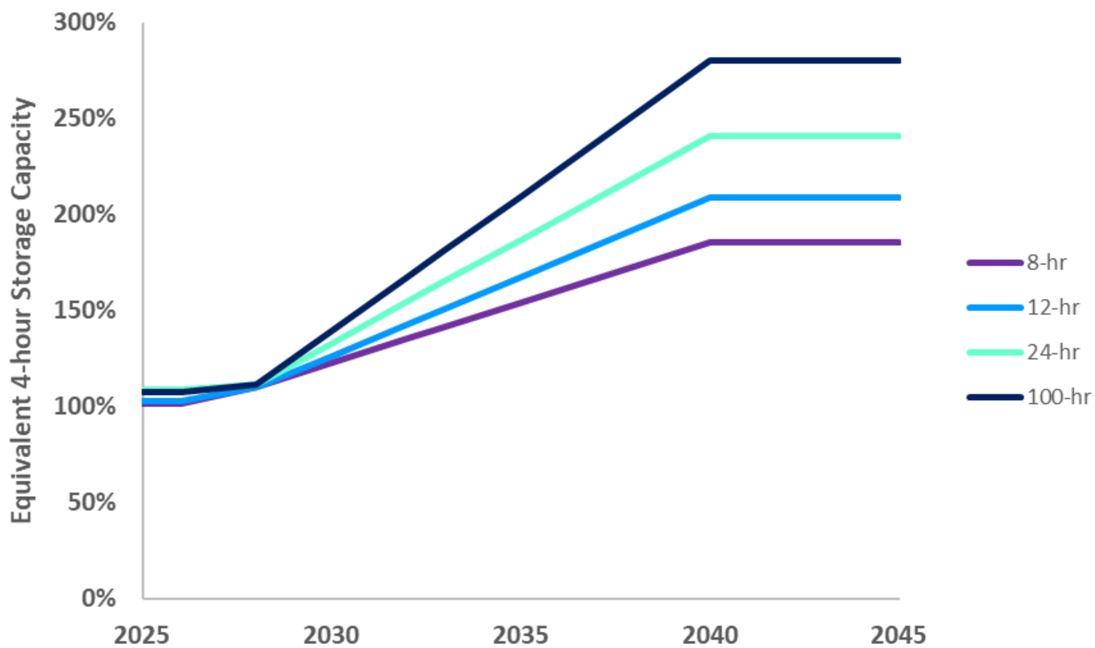
To reflect the dynamic that a solar resource's reliability contribution will typically scale with capacity factor, the capacity (in MW) of individual solar resources used in the multivariate linear equations is scaled by the ratio of each solar resource's capacity factor to that of the solar resource capacity factor used in the SERVM ELCC simulations. The capacity (in MW) of storage resources used in the multivariate linear equation is the 4-hour duration equivalent, calculated for each individual storage resource as storage resource capacity [MW] * MIN(1, duration [h] / 4 h).

### 7.1.10 Candidate Long-Duration Storage

Candidate long-duration energy storage (LDES) resources are accounted for on the storage dimension of the solar + storage ELCC surface. The nameplate capacities of candidate long (8+ hour) duration storage resources counted on the surface are multiplied by scalar factors (> 1) to reflect the greater reliability contribution of longer duration storage resources relative to the 4-hour duration battery storage resource represented by the ELCC surface. The multipliers were calculated by estimating the ratio of LDES marginal ELCC to 4-hour storage marginal ELCC at various penetrations of solar and 4-hour storage on the solar + storage surface. This ratio provides an "exchange rate" of reliability value between storage resources of different durations. The key assumption underlying this methodology was that the solar + storage surface would have approximately the same shape or form regardless of the duration of the storage resource represented by the surface, with the main difference being that longer duration storage resources' ELCCs decline more slowly with increasing storage penetration. The multipliers used to model long-duration storage ELCC in RESOLVE vary by year based on the expected level of 4-hour storage penetration on the CAISO system in each year. The multiplier values for 8-hour, 12-hour, 24-hour, and 100-hour duration storage resources are shown below. These long-duration storage resources represent, respectively, 8-hour lithium-ion battery storage, 12-hour pumped hydro storage, 24-hour compressed air energy storage, and 100-hour iron-air battery storage.

Candidate pumped hydro storage is modeled on the solar + storage ELCC surface as a 12-hr resource, with the respective multiplier.

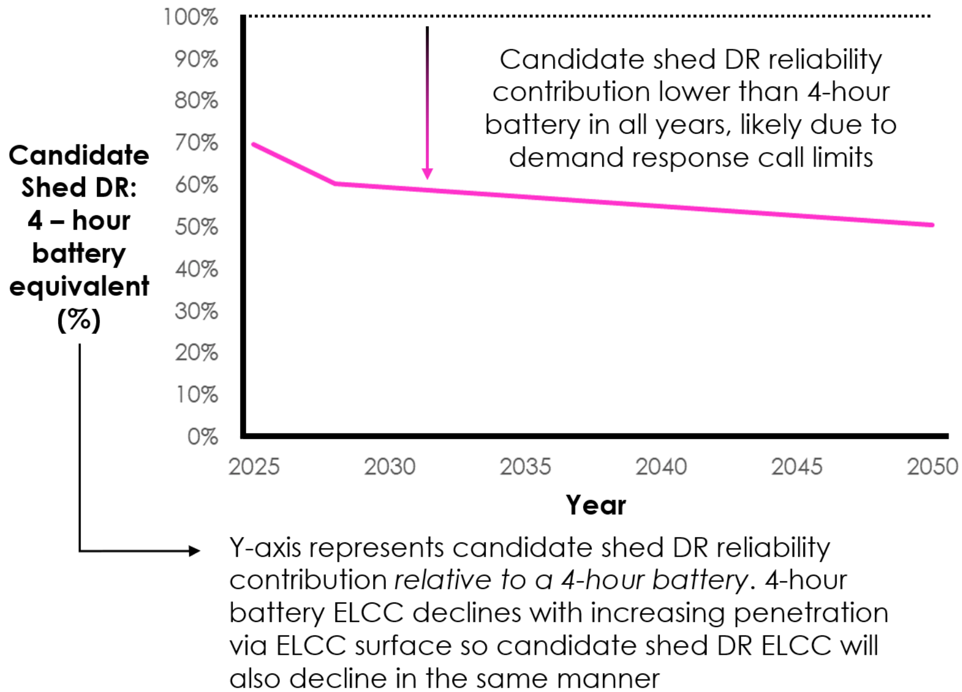
*Figure 40. Nameplate Multipliers for Long-Duration Storage ELCC Accounting on Solar + Storage Surface*




### 7.1.11 Candidate Demand Response

Candidate shed demand response resources are modeled on the storage dimension of the solar + storage ELCC surface. This enables RESOLVE to capture the antagonistic interactive effect between use- and duration- limited demand response with energy and duration limited battery storage resources. Marginal ELCCs were calculated for additional demand response at various points on the solar and storage surface corresponding to the installed capacity in the 38MMT updated PSP portfolio. These marginal ELCCs were compared to the 4-hr battery storage marginal ELCCs at that point on the surface and a de-rate factor was calculated. For example, if battery storage provides an 80% marginal ELCC and demand response provides a 60% marginal ELCC, then the 4-hr battery equivalent de-rate factor is 60%/80% = 75%. Figure 41 below shows the demand response de-rate factor used for each year.

*Figure 41. Demand Response Marginal ELCCs Relative to 4-hr Battery Storage*




Candidate shift demand response resources are also modeled on a solar + storage ELCC surface. A scaling factor is also applied to the ELCC to account for the availability of shift demand response relative to an equivalent capacity of battery storage. This scaler is calculated as the average amount of shift down potential during the critical evening net peak hours of 6 to 10 P.M. divided by the "nameplate capacity" of the shift DR resource.

### 7.1.12 VGI Reliability Contribution

Newly-added VGI resources are put on the 4-hr storage dimension of the solar + storage ELCC surface to account for the interactive effect between grid storage and VGI. Given that VGI is not as fully available as grid-scale storage to provide power at its nameplate capacity in every single hour, a scaling factor will be applied to normalize VGI shift down capability relative to its "nameplate capacity" during the 4-hr evening net peak (e.g., 6-10pm)

The scaling factor calculates the total shift down potential (kWh) over the charger's nameplate energy capacity (kWh) during the net peak hours. [166]The final 4-hour battery equivalent

[166] The nameplate capacity here is defined as the capacity of the charger, which is slightly different from the definition in the 2022 September Inputs and Assumptions workshop. Stakeholders has complaint about that original nameplate capacity definition being confusing. In the 2022 September Inputs and Assumptions workshop, the nameplate capacity was defined as the capacity to charge or discharge in either direction and was multiplied by 2 for V2G.

capacity of VGI is calculated as follows. VGI will be put on the storage dimension of the solar + storage ELCC surface, together with storage and shed demand response, to determine its ELCC value.

> Battery (4hr) Equivalent Capacity of VGI (MW) = VGI Nameplate Capacity of Chargers (MW) * VGI Scaling Factor (%)

### 7.1.13 Imports

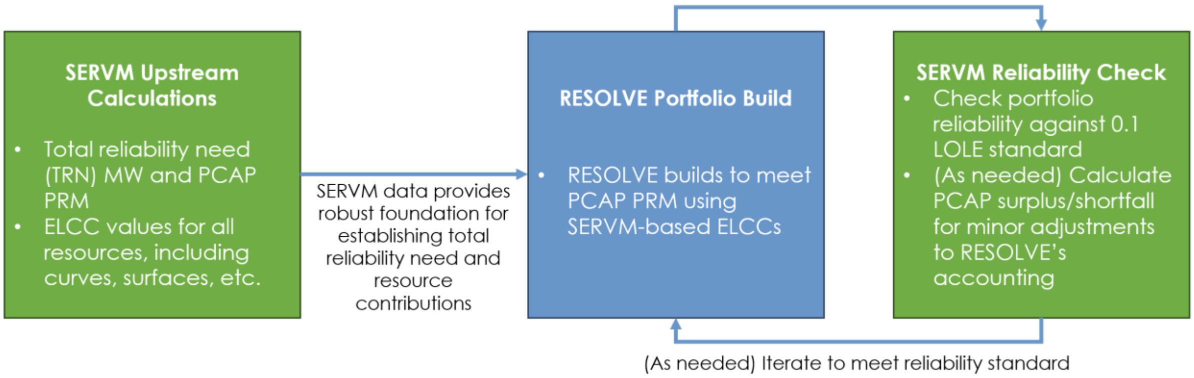
RESOLVE models an amount of "Unspecified" imports as firm imports that count towards supporting reliability in the CAISO. 4,000 MW is the default value for unspecified firm imports modeled in RESOLVE. In previous cycles, RESOLVE also modeled "specified" imports that count towards supporting reliability in the CAISO. These "specified" imports included the CAISO share of the following four resources: Hoover, Palo Verde, Intermountain Power Plant, and Sutter. In this cycle, the CAISO share of these resources are modeled as units within CAISO to align with SERVM and reflect that those CAISO shares fully count towards supporting CAISO reliability. The "specified" import category is eliminated from RESOLVE.

In SERVM, all units outside CAISO that may deliver energy to CAISO load are subject to SERVM's simultaneous import constraint, which is configured as 4,000 MW during peak hours (5pm to 10pm) in June through September, and as 11,040 MW (reflective of the current CAISO maximum import limit) during all other hours.

### 7.1.14 Additional Adjustments to CAISO Load/Resource Balance

As needed, additional ad hoc adjustments are made to the CAISO reliability need or resource contributions modeled in RESOLVE. These may include adjustments for "remote generators", which are external resources modeled as CAISO resources but contained within the unspecified import limit, to avoid double counting their capacity. As shown in Figure 42 below, additional calibration adjustments are made through iteration between RESOLVE and SERVM to result in reliable portfolios across the planning horizon. These may account for resource interactive effects beyond those captured in the ELCCs (e.g., higher wind and solar/storage effects beyond the 2030 values captured, interactions between shaped imports and CAISO resources, etc.).

*Figure 42. RESOLVE-SERVM reliability-related process flow*




## 7.2 Local Resource Adequacy Constraint

In addition to System Resource Adequacy requirements developed by the CPUC, CAISO identifies Local Capacity Requirements (LCR) that define minimum local resource capacity required in each local area to meet established reliability criteria. These LCRs reflect that electrical areas and sub-areas throughout the state have limited transmission import capabilities. Since the 2019-2021 IRP cycle, the CPUC IRP has assumed that a minimum amount of gas resource capacities located in local areas must be maintained for local reliability needs (see 7.2.1), though CPUC staff continue work on a more granular analysis to capture LCR need (see 7.2.2).

### 7.2.1 Minimum Retention of Gas-Fired Resources in Local Areas

Many dispatchable gas plants that would potentially not be economically retained by RESOLVE are currently serving local capacity needs. For instance, the 2023 and 2027 CAISO Local Capacity Technical Study (LCTS)[167] indicate that the Stockton local area is deficient by 2023, and so is the North Bay-North Coast local area by 2027. For this cycle, the CPUC IRP assumes that storage that is built for other system needs (e.g., PRM) can be located in local areas as needed to also mitigate local capacity needs identified. CPUC Staff analysis uses the LCTS to determine the minimum generation capacity that must be retained on the CAISO system. The RESOLVE optimization enforces the minimum retention values (Table 89) for each class of generator in each year, and resource replacements by local 4-hour battery storage will be determined by RESOLVE.[168]

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[167] https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx
[168] The maximum potential for 4-hr batteries to replace LCR capacity is based on the LCTS study (https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx).

*Table 89. Minimum gas retention*

| RESOLVE Resource | 2027 Planned Capacity (MW) | Gas Contributing to Local Capacity Requirements (MW) | Minimum Retained Existing Gas Capacity (MW) |
|---|---|---|---|
| CAISO_CCGT1 | 14,352 | 9,263 | Replacement by resource to be decided by RESOLVE[169] |
| CAISO_CCGT2 | 2,528 | 2,528 | |
| CAISO_Peaker1 | 2,668 | 2,599 | |
| CAISO_Peaker2 | 5,536 | 4,825 | |
| CAISO_Reciprocating_Engine | 259 | 211 | |
| **Total** | **25,343** | **19,426** | **15,199** |

### 7.2.2 Development of Additional Local Resource Adequacy Modeling

Additionally, CPUC staff and E3 are in the process of developing a new, experimental local capacity module of RESOLVE that seeks to simulate the CAISO's deterministic local reliability planning standard. This tool will consider the local area planning load forecast under binding conditions identified via the CAISO's Local Capacity Technical Studies (LCTS) and be capable of optimizing a least-cost portfolio that meets local capacity requirements considering local resource additions, retirements, and transmission upgrades. Early versions of this module may be limited to modeling one individual local area at a time. This modeling will also seek to connect to the RESOLVE system optimization to ensure the proper feedback loop between resources needed for local reliability and those needed for system reliability.

Stakeholders will be able to provide feedback on the proposed approach and data inputs for this new local capacity functionality at a later date.

[169] RESOLVE may replace with local 4-hr batteries.

# 8. Greenhouse Gas Emissions and Clean Energy Policies

## 8.1 Greenhouse Gas Constraint

RESOLVE includes optionality to enforce a greenhouse gas (GHG) constraint on CAISO emissions. For the 2022-2023 IRP cycle, for the modeling periods through 2035 the modeling will incorporate the GHG trajectories established in the April 2022 Administrative Law Judge's Ruling Establishing Process for Finalizing Load Forecasts and Greenhouse Gas Emissions Benchmarks for 2022 Integrated Resource Plan Filings[170], which adopted the statewide GHG emissions planning trajectories for 2030 and through 2035 shown in Table 90 below. The baseline emissions are benchmarked to the power sector emissions of 59.5 MMT in 2020 in California, based on the 2022 California's Greenhouse Gas Inventory by Scoping Plan Category.[171] The emissions trajectory from 2023 to 2029 is linearly interpolated between the emissions in 2020 and the target in 2030. Similarly, the 2040 value is a straight-line interpolation between the 2035 value and the CAISO footprint of the energy-related statewide 2045 target from the 2022 CARB Scoping Plan.[172] As in the previous IRP cycles, the statewide emissions of the electricity sector are multiplied by 82%—the share of ARB's forecasted 2030 allocation of emissions allowances to distribution utilities within the CAISO footprint[173]—to yield a target for CAISO LSEs.

It is notable that the 25 MMT and the 30 MMT by 2035 are the new trajectory names replacing the previous 30 MMT and 38 MMT by 2030 trajectories and have the same 2030 and 2035 statewide emissions targets. Both of these trajectories reach the same 8 MMT by 2045 statewide emissions target. Lower long-term emissions targets might be used in some sensitivity analysis.

*Table 90. Options for GHG emissions constraints (million metric tons – CAISO footprint)*

| Scenario Setting | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| 25 MMT by 2035 statewide & 8 MMT by 2045 | 36.5 | 34.1 | 29.2 | 24.3 | 20.3 | 13.7 | 7.1 |
| 30 MMT by 2035 statewide & 8 MMT by 2045 | 39.9 | 38.2 | 34.6 | 31.1 | 24.8 | 16.0 | 7.1 |

[170] Found here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M469/K615/469615281.PDF
[171] https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/ghg_inventory_by_scopingplan_00-20.xlsx

[172] Found here: https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf
[173] CARB's allowance allocation to distribution utilities from 2021-2030 is available here: https://www.arb.ca.gov/regact/2016/capandtrade16/ attach10.xlsx

## 8.2 Greenhouse Gas Accounting

RESOLVE tracks greenhouse gas emissions attributed to entities within the CAISO footprint using a method consistent with the California Air Resources Board's (CARB) regulation of the electric sector under California's cap & trade program.

### 8.2.1 CAISO Generators

The annual emissions of generators within the CAISO are calculated in RESOLVE as part of the dispatch simulation based on (1) the annual fuel consumed by each generator; and (2) an assumed carbon content for the corresponding fuel.

### 8.2.2 Imports to CAISO

RESOLVE attributes emissions to generation that is imported to CAISO based on the deemed emissions rate for unspecified imports as determined by CARB. The assumed carbon content of imports based on this deemed rate is 0.428 metric tons per MWh[174]—a rate slightly higher than the emissions rate of a combined cycle gas turbine.

Specified imports to CAISO are modeled as if the generator is located within CAISO, therefore any emissions associated with specified imports are included with emissions associated with CAISO generators. The majority of specified imports to CAISO are non-emitting resources, though imports from the coal-fired Intermountain Power Plant are simulated through the mid-2020s.

### 8.2.3 Behind-the-meter CHP Emissions Accounting

CARB Scoping Plan electric sector emissions accounting includes emissions from behind-the-meter CHP generation. BTM CHP is represented as a reduction in load in IRP, and therefore emissions from BTM CHP are not directly captured in RESOLVE's generation dispatch.[175] To continue to retain consistency with CARB's Scoping Plan accounting conventions in the 2022-2023 IRP cycle, emissions associated with BTM CHP generation are included under the GHG constraint, thereby reducing the emissions budget available for supply-side resources. BTM CHP emissions are calculated from 2022 IEPR, averaging 4.8 MMT/yr in each year from 2023-2030 and slightly declining over time to reach about 4.0 MMT/yr in 2045.

[174] Rules for CARB's Mandatory Greenhouse Gas Reporting Regulation are available here: https://ww2.arb.ca.gov/mrr-regulation

[175] Due to these accounting discrepancies, in 2017 there was an estimated 4 MMT difference between RESOLVE and the Scoping Plan. Specifically, a 42 MMT target in RESOLVE was equivalent to a 46 MMT in the Scoping Plan.

## 8.3 Clean Energy Policies

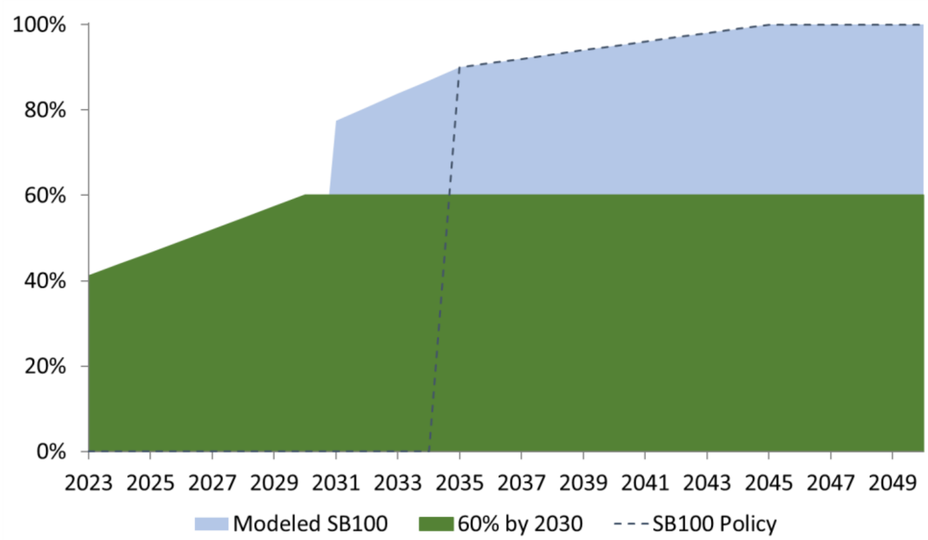
### 8.3.1 RPS requirement

RESOLVE includes a constraint that enforces RPS compliance in CAISO in all modeled years. Since SB100 policy is modeled separately, this results in the selection of a least-cost portfolio of candidate renewable resources to meet RPS compliance, while satisfying any additional constraints. Enforcing the RPS and/or greenhouse gas constraints (discussed in the previous section) typically results in selection of candidate renewable resources.

### 8.3.2 SB 100 Policy

Senate Bill 100 (SB100) increased the state's renewable portfolio standard to 60% by 2030 and set a goal to supply 100% of retail electricity sales from carbon-free resources by 2045. SB-1020 Clean Energy, Jobs, and Affordability Act of 2022 added two additional clean energy retail sales targets of 90% by 2035 and 95% by 2040.[176] In the PSP modeling, the SB100 clean retail sale targets are applied starting from 2031 (modeled earlier than the first target year to allow for a much smoother compliance), and in addition to RPS eligible resources, electricity generation from resources such as large hydro, nuclear (Palo Verde) and specified hydro imports from NW are eligible to contribute to. For interim years, the target is linearly interpolated between the two consecutive target years.

*Figure 43. RPS and SB100 compliance*




[176] Bill Text - SB-1020 Clean Energy, Jobs, and Affordability Act of 2022. (ca.gov)

### 8.3.3 RPS Banking

As a compliance option for CAISO's RPS requirement, RESOLVE includes the ability to retire banked Renewable Energy Certificates (RECs) - renewable generation in excess of an LSE's RPS compliance requirements that can be redeemed during subsequent compliance periods. The volume of RECs that are banked at any point in time can be material, and the timing of REC redemption may significantly impact the selection of candidate resources in the years that the RPS constraint is driving renewable investment. For the 2022-2023 IRP cycle, RESOLVE models a specified schedule of bank redemption (GWh in each year.) This approach was used in previous cycles as well. IOUs 2022 Renewable Net Short reports, and 2021 RPS compliance reports are compiled to determine the banked RPS schedule. The bank usage in RESOLVE is slightly smoothed in consideration of uncertainty in RPS bank usage schedule IOUs are planning for. RPS bank usage in RESOLVE reduces the amounts of RPS eligible generation from resource portfolios.

*Table 91. Modeled banked RPS usage schedule.*

| Year | 2025 | 2026 | 2028 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|---|---|
| Banked RPS (GWh) | 9,757 | 8,345 | 8,844 | 7,241 | 0 | 0 | 0 |

---- DOCUMENT ENDS----

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