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Inputs & Assumptions:
CEC SB100 Joint Agency Report

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1. Introduction

This document describes the key data elements and sources of inputs and assumptions for the California Energy Commission SB100 Joint Agency Report RESOLVE modeling.

The inputs, assumptions, and methodologies are applied to create optimal portfolios for the state of California's electric system that reflect different assumptions regarding load growth, technology costs and potential, fuel costs, and policy constraints.

1.1 Overview of the RESOLVE model

The high-level, long-term identification of new resources that meet California's policy goals is developed using the RESOLVE resource planning model. The RESOLVE model used in this analysis was based off the model used in the 2019/2020 California Public Utility Commission's (CPUC) Integrated Resource Planning (IRP) process. The CPUC uses RESOLVE to develop the Reference System Portfolio, a look into the future that identifies a portfolio of new and existing resources that meets the GHG emissions planning constraint, provides ratepayer value, and responds to reliability needs. The CPUC uses RESOLVE for the development of the Reference System Portfolio 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 IRP 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, renewable portfolio standard goals, reliability during peak demand events, and other system requirements. RESOLVE typically focuses on developing portfolios for one zone, in this case a zone representing the State of California 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 SB100 - CEC version of RESOLVE includes three zones: one zone capturing California balancing authorities and two zones that represent regional aggregations of out-of-state balancing authorities.[1]

[1] A seventh resource-only zone was added in the 2019-2020 IRP to simulate dedicated imports from Pacific Northwest hydroelectric resources. This zone does not have any load and does not represent a BAA.

RESOLVE can solve for:

- Optimal investments in renewable resources, energy storage technologies, demand response resources, distributed energy resources, and new thermal gas plants, as well as retention of existing thermal resources.

Subject to the following constraints:

- An annual constraint on delivered renewable energy that reflects Renewable Portfolio Standard (RPS) policy;
- An annual constraint on greenhouse gas emissions;
- An annual Planning Reserve Margin (PRM) constraint to maintain capacity adequacy and reliability;
- Operational restrictions on generators and resources;
- Hourly load and reserve requirements; and
- Constraints on the ability to develop specific new resources.

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

1.2 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 California 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 planned resources that are assumed to be operational in the year being modeled.
- **Section 4 (Candidate 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 5 (Pro Forma)** describes the financial model used to calculate levelized fixed costs of candidate resources in RESOLVE.
- **Section 6 (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 (Renewable Portfolio Standard and SB100 Policy)** discusses assumptions and accounting used to characterize renewable portfolio standard and SB100 policy targets.

2. Load Forecast

2.1 Statewide forecast

The primary source for load forecast inputs (both peak demand and total energy) is the CEC's 2019 Integrated Energy Policy Report (IEPR) Demand Forecast to 2030. The CEC's 2018 Deep Decarbonization in a High Renewable Future report, as well as the CPUC IRP PATHWAYS modeling, are also used to provide long-term forecasts out to 2045.

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:

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

Data sources for demand-side modifier assumptions are discussed in subsequent sections.

Demand forecast inputs are frequently presented as demand at the customer meter. However, the RESOLVE dispatch optimization uses demand at the generator bus-bar. Consequently, demand forecasts at the customer meter are grossed up for transmission & distribution losses based on the average losses across the CAISO zone assumed in the CEC's IEPR Demand Forecast of 7.24%.

2.1.1 Baseline Consumption

Baseline consumption refers to a counterfactual forecast of electricity consumption that captures economic and demographic changes in California but does *not* include the impact of demand-side modifiers. The baseline consumption forecast used is derived from retail sales reported in the CEC's 2019 IEPR Demand Forecast along with accompanying information on the magnitude of embedded demand-side modifiers. Creating a baseline consumption forecast enables different combinations of demand-side modifiers to be used, including combinations that are not explored in the IEPR Demand Forecast. The derivation of baseline consumption from the retail sales forecast is shown in Table 1.

Table 1. Derivation of Baseline Consumption from the CEC IEPR Demand Forecast (GWh)

Component	2020	2025	2027	2030
CEC 2019 IEPR Managed Retail Sales	*250,234*	*250,916*	*252,430*	*255,991*
+ Mid AAEE	2,002	7,129	8,766	10,297
+ Behind-the-Meter PV	19,014	31,624	35,375	40,828
+ Behind-the-Meter CHP	14,064	14,134	14,160	14,198
- TOU rate effects	0	37	39	43
- Electric Vehicles	4,385	10,955	12,597	15,038
= Baseline Consumption	280,929	292,812	298,094	306,233

2.1.2 Electric Vehicles

The CEC SB 100 modeling includes four options for forecasting future electric vehicle demand. The first option is based directly on the IEPR Mid Demand forecast. The remaining three options are based on scenarios from the CEC 2018 Deep Decarbonization report, which extend beyond the 2030 timeframe to reflect different levels of electrification. Post-2030 loads are described in section 2.1.9.

Table 2. Electric vehicle forecast options (GWh)

RESOLVE Scenario Setting	2020	2025	2027	2030
CEC 2019 IEPR - Mid Demand	4,385	10,955	12,597	15,038
CEC 2018 Deep Decarbonization - High Biofuels	1,353	5,521	8,663	13,535
CEC 2018 Deep Decarbonization - High Electrification	1,353	5,521	8,663	13,535
CEC 2018 Deep Decarbonization - High Hydrogen	1,353	5,521	8,663	13,535

2.1.3 Building Electrification

Two options for future building electrification demand are included. The first reflects the IEPR assumption of no incremental building electrification through 2030, and the second is based on the assumptions in the CEC Deep Decarbonization report.

Table 3. Building electrification forecast options (GWh)

RESOLVE Scenario Setting	2020	2025	2027	2030

No Incremental Building Electrification[2]	-	-	-	-
CEC 2018 Deep Decarbonization [3]	-	92	724	3686

2.1.4 Other Transport Electrification

The forecast options for electrification of "other" end uses (e.g. ports, and airport ground equipment) are based on the CEC 2019 IEPR Demand Forecast, and on the CEC Deep Decarbonization Report.

Table 4. Other transport electrification forecast options (GWh)

RESOLVE Scenario Setting	2020	2025	2027	2030
CEC 2019 IEPR - Mid Demand	-	-	-	-
CEC 2018 Deep Decarbonization - High Biofuels	1,461	3,643	5,206	8,067
CEC 2018 Deep Decarbonization - High Electrification	1,461	3,643	5,206	8,070
CEC 2018 Deep Decarbonization - High Hydrogen	1,374	3,163	4,328	6,228

2.1.5 Behind-the-Meter PV

The CEC SB 100 scenarios include a forecast for behind-the-meter (BTM) PV adoption, which is based on the CEC's IEPR Demand Forecast.

Table 5. Behind-the-meter PV forecast options (GWh)

RESOLVE Scenario Setting	2020	2025	2027	2030
CEC 2019 IEPR - Mid PV	19,014	31,624	35,375	40,828

2.1.6 Behind-the-meter CHP and Other Non-PV Self Generation

The forecast of non-PV self-generation is based on the CEC 2019 IEPR Demand Forecast. On-site combined heat & power (CHP) that does not export to the grid makes up the majority of this component. The IEPR primarily models on-site CHP using projections based on past on-site CHP

[2] This is consistent with the IEPR demand forecast which does not include incremental building electrification, and with the CARB 2016 Scoping Plan "SP" scenario.

[3] The High Electrification, High Hydrogen and High Biofuels Scenarios from the CEC's 2018 "Deep Decarbonization in a High Renewables Future" have the same building electrification assumptions.

generation data. CHP units that export energy to the grid are separately discussed in section 3. Forecasts for BTM CHP and the remaining non-PV self-generation are shown in the tables below.

Table 6. Forecast of Behind-the-meter CHP (GWh)

Scenario Setting	2020	2025	2027	2030
CEC 2019 IEPR - Mid Demand	14,064	14,134	14,160	14,198

2.1.7 Energy Efficiency

The CEC SB 100 modeling includes a forecast for energy efficiency achievement among California load-serving entities based on the Mid-AAEE scenario included in the CEC's 2019 IEPR Demand Forecast. "Additional Achievable Energy Efficiency" (AAEE) refers to efficiency savings beyond current committed programs.

Table 7. Energy efficiency forecast options (GWh)

RESOLVE Scenario Setting	2020	2025	2027	2030
CEC 2019 IEPR – Mid-Mid AAEE	2,907	11,817	14,687	17,711

2.1.8 Time-of-Use Rate Impacts

The CEC SB 100 modeling includes two options for representing different impacts of residential time-of-use (TOU) rate implementation on retail load. The first assumes no impact to load shape. The second corresponds to mid residential TOU scenarios from CEC's 2018 IEPR Demand Forecast. As modeled, TOU rates modify the hourly load profile but have little impact on annual load.

Table 8. Residential TOU rate implementation load impacts (GWh)

RESOLVE Scenario Setting	2020	2025	2027	2030
None	—	—	—	—
CEC 2018 IEPR	0	37	39	43

2.1.9 Load extrapolation to 2045

The CEC's 2018 Deep Decarbonization in a High Renewables Future report is used to provide long-term forecasts out to 2045 for the three "mitigation" scenarios (High Electrification, High

Biofuels, and High Hydrogen). The CPUC IRP 2020 PATHWAYS Reference scenario is used to provide long-term forecasts out to 2045 for the Reference scenario modeling. Each scenario follows the PATHWAYS assumptions for load modifiers, including electric vehicles, other transport electrification, building electrification, and hydrogen production. The High Electrification scenario is picked as the default mitigation scenario in the study because it provides a balanced decarbonization pathway between electrification and low-carbon fuels with relatively low costs and commercially available technologies.

All scenarios follow the same assumptions on energy efficiency and baseline consumption. Energy efficiency is held flat after 2030, because energy efficiency is included in the baseline loads from PATHWAYS. PATHWAYS does not report baseline consumption directly, but rather reports baseline consumption net of energy efficiency.

Table 9: Reference Load Forecast (post-2030 values based on CPUC IRP 2020 PATHWAYS Reference)

RESOLVE Scenario Setting	2027	2030	2035	2040	2045
Baseline Consumption	298,094	306,233	313,580	323,128	333,989
Electric Vehicles	12,597	15,038	25,164	37,587	50,185
Other Transport Electrification	-	-	2,328	4,947	7,613
Building Electrification	-	-	268	591	912
Hydrogen Production	-	-	-	-	-
Energy Efficiency	*(14,687)*	*(17,711)*	*(17,711)*	*(17,711)*	*(17,711)*
Total	**296,004**	**303,560**	**323,629**	**348,542**	**374,988**

Table 10. CEC Pathways High Biofuels Load Forecast (GWh)

RESOLVE Scenario Setting	2027	2030	2035	2040	2045
Baseline Consumption	298,094	306,233	313,580	323,128	333,989
Electric Vehicles	8,663	13,535	23,567	31,250	37,176
Other Transport Electrification	5,206	8,067	15,692	24,796	32,746
Building Electrification	724	3,686	14,551	29,193	42,810
Hydrogen Production	-	-	-	-	-
Energy Efficiency	*(14,687)*	*(17,711)*	*(17,711)*	*(17,711)*	*(17,711)*
Total	**298,000**	**313,810**	**349,679**	**390,656**	**429,010**

Table 11. CEC Pathways High Electrification Pathways Load Forecast (GWh)

RESOLVE Scenario Setting	2027	2030	2035	2040	2045
Baseline Consumption	298,094	306,233	313,580	323,128	333,989
Electric Vehicles	8,633	13,954	28,252	39,351	46,863
Other Transport Electrification	5,206	8,070	15,875	25,867	34,401
Building Electrification	724	3,686	14,551	29,193	42,810
Hydrogen Production	-	-	-	-	-
Energy Efficiency	*(14,687)*	*(17,711)*	*(17,711)*	*(17,711)*	*(17,711)*
Total	**297,970**	**314,232**	**354,547**	**399,828**	**440,352**

Table 12. CEC Pathways High Hydrogen Load Forecast (GWh)

RESOLVE Scenario Setting	2027	2030	2035	2040	2045
Baseline Consumption	298,094	306,233	313,580	323,128	333,989
Electric Vehicles	8,633	13,954	28,252	39,351	46,863

Other Transport Electrification	4,328	6,228	11,176	16,109	20,748
Building Electrification	724	3,686	14,551	29,193	42,810
Hydrogen Production	2,272	5,559	23,065	73,892	108,812
Energy Efficiency	*(14,687)*	*(17,711)*	*(17,711)*	*(17,711)*	*(17,711)*
Total	**299,364**	**317,949**	**372,913**	**463,962**	**535,511**

2.2 Peak Demand Forecast

To ensure that the electricity system has adequate resources to reliably operate the system during the hours of highest demand, RESOLVE's planning reserve margin constraint guarantees that all portfolios have at least a 15% margin above the 1-in-2 net peak demand in all modeled years. The peak demand of the system can significantly impact resource portfolio selection by increasing the value of resources that can produce energy during peak periods.

Both the timing and magnitude of peak demand are impacted by changes in demand-side modifiers, including but not limited to behind-the-meter solar and storage, energy efficiency, and new loads from electrification of transportation and other fossil-fueled end uses. Calculation of system net peak demand takes into account the combined impact of all of the demand-side modifiers.

2.2.1 Mid Managed Peak Demand Projection - Through 2030

To be consistent with the use of a Single Forecast Set for electric resource planning activities, the managed net peak through 2030 is calculated using CEC 2018 IEPR "Mid case" assumptions on the annual level of demand and various demand modifiers. An hourly 8760 timeseries of California state-wide electric demand – net of demand modifiers – for the years 2018-2030 is developed by combining peak-load normalized hourly demand shapes from the 2018 IEPR with annual demand projections from the 2019 IEPR. Peak demand impacts for individual demand modifiers are not calculated for the IEPR Mid case because interactive effects between hourly shapes and the timing of peak demand result in demand modifier peak impacts that are interdependent and non-linear. As outlined below, all demand modifiers with an hourly shape are added or subtracted from the hourly consumption forecast, resulting in a peak demand in each year that is referred to as the "Managed Peak" demand.

California Hourly Consumption Load: Mid Baseline

+ Other Electrification: Mid (included in hourly consumption load)

- Non-PV Self Generation (predominantly BTM CHP) (included in hourly consumption load)

- Behind-the-Meter (BTM) Storage Peak Impact (included in hourly consumption load)

+ Load from Vernon and SVP data centers

+ Time-Of-Use: Mid (can increase or decrease hourly demand)

+ Climate Change Impacts: Mid (can increase or decrease hourly demand)

+ Light-Duty Electric Vehicles: Mid

- Additional Achievable Energy Efficiency: Mid-Mid

- Committed BTM PV: Mid

California Managed Net Mid Peak, Coincident, through 2030, excluding Load Modifying Demand Response (LMDR)

- LMDR: Mid

California Managed Net Mid Peak, Coincident, through 2030

Notes:

- The peak demand impacts of Other Electrification and non-PV Self Generation (including BTM combined heat and power and BTM storage) are embedded in the CEC IEPR's hourly consumption load shape, and therefore do not have separate hourly profiles.
- The CEC represents the peak discharge capability of BTM storage as the installed BTM storage capacity, reduced by a 1% per year degradation rate (cumulative), and then de-rated to 90% output during peak.
- The peak demand impacts of load modifying demand response are not represented using an hourly load profile and are instead subtracted from the Managed Peak.

2.2.2 Peak Demand Post-2030 Years

RESOLVE simulations require peak demand forecasts for every year that is simulated. The CEC 2019 IEPR forecasts demand through 2030, but the scenarios explored in the CEC SB100 analysis extend past 2030, requiring an extrapolation of the peak demand to years beyond 2030.

To develop peak demand forecasts for years after 2030 for baseline consumption, electric vehicles, energy efficiency, and BTM PV, information from the peak demand sensitivities is used to calculate a normalized peak demand impact. For each of the demand modifiers, the peak demand difference from Mid in the year 2030 is normalized to the increase or decrease in annual demand, resulting in the peak demand increase per unit of demand modifier (Δ MW_{peak} / Δ GWh_{annual}). This factor is used to calculate the increase or decrease in peak demand resulting from a change in annual demand relative to 2030.

2.2.3 Building Electrification and Other Transportation Peak Demand Impact

The peak impact (Δ MW_{peak} / Δ GWh_{annual}) of building and other transportation electrification are calculated using an extrapolated hourly demand projection for the year 2050. The peak demand impact is calculated by adding or removing a small amount of demand and observing the change in peak.

2.2.4 Peak demand adjustment for modeling BTM PV and Storage as supply side

Resource adequacy needs are typically calculated with BTM resources represented on the demand side. In this framework, BTM resources contribute to system peak needs by reducing the 1:2 system peak. RESOLVE represents BTM PV and Storage resources as supply-side resources in both hourly dispatch and resource adequacy retirements. Two adjustments are made to the MW value of RESOLVE's planning reserve margin constraint that align the supply-side treatment of these resources with the typical demand-side resource adequacy representation:

- The peak reduction from each resource is added back to RESOLVE's planning reserve margin MW need. This is necessary to avoid double counting the peak reduction of BTM PV and storage.
  - The peak reduction from BTM PV is calculated by removing Committed hourly production profiles from the "Mid" load profile and recalculating the peak demand in each year.
  - The peak reduction from BTM storage does not vary by hour, so the BTM storage peak reduction is added back to the planning reserve margin target directly.
- Demand-side resources reduce the capacity needed above the peak load because the planning reserve margin (PRM) is calculated as a percentage (typically 15%) above the managed load peak. Consistent with Resource Adequacy accounting, demand-side resources reduce the managed load peak, so the 15% margin above 1-in-2 peak demand is not held for these resources. When modeling demand-side resources on the supply side, the planning reserve margin that is input into RESOLVE is reduced by the PRM percentage multiplied by the MW of peak reduction from BTM resources modeled on the supply-side in RESOLVE.

Figure 2.1. Translation of demand-side resources to the supply-side in RESOLVE. Diagram is conceptual and is not to scale. The heavy black line indicates the PRM MW target.

Peak Capacity (MW)	PRM Calculation with BTM resources on the demand-side	PRM Calculation without PRM margin reduction for BTM (not used)	PRM Calculation in RESOLVE - with BTM resources on the supply-side
		(4) 15% PRM on supply-side BTM resources (15% * (3))	(PRM margin from BTM resources modeled as supply not included)
		(3) Peak Capacity reduction from BTM PV and Storage, added back to supply side	(3) Peak Capacity reduction from BTM PV and Storage, added back to supply side
	(2) 15% PRM on Managed Peak (15% * (1))	(2) 15% PRM on Managed Peak (15% * (1))	(2) 15% PRM on Managed Peak (15% * (1))
	(1) Managed Net Load Peak	(1) Managed Net Load Peak	(1) Managed Net Load Peak

2.3 Other Zones

RESOLVE uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes three zones: one zone 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)) and two zones that represent regional aggregations of out-of-state balancing authorities.[4] The constituent balancing authorities included in each RESOLVE zone are shown in Table 45 (Section 6.5).

Demand forecasts for zones outside California are developed by a process similar to California forecasts. Forecasts for the zones outside of California (the Pacific Northwest and the Southwest), WECC's 2028 Anchor Data Set (ADS) Phase 2 V1.2 is used as the basis for load projections. Sales forecasts net of demand-side modifiers are combined with available

[4] The 2019-2020 IRP 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.

information in the ADS related to demand-side modifier and consumption forecasts. This data is then be aggregated to the RESOLVE zones.

The demand forecasts for each non-California zone are grossed up for transmission and distribution losses. Demand forecasts for zones outside California are shown in the table below.

Table 13. Non-California Net Energy for Load - grossed up for T&D losses (GWh)

RESOLVE Zone	2020	2022	2026	2030	2045
NW	240,828	243,368	248,416	253,973	273,690
SW	142,457	146,338	152,407	158,873	183,496

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 for much of its energy and capacity for a significant portion of its useful life. 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) and are far enough along in the development process that it is reasonable to assume that the resource will be completed. To reflect the potential for project failure these resources are discounted by 5 percent, a value based on RPS Procurement Plans and stakeholder feedback.
- Resources not optimized: Future projected resource additions that are expected, but not appropriate for optimization (e.g., achievement of the CPUC storage target).

Baseline resources are assembled from the primary sources listed in Table 14 and are further described below.

Table 14. Data Sources for Baseline Resources

Zone	Online Status	Generator type	Dataset used
In California	Existing	Renewable, Storage, and Non-Renewable	CAISO Master Generating Capability List, CAISO Master File and WECC ADS for non-CAISO BAA generators
In California	Under development	Renewable and Storage	RPS Contract Database and data requests
In California	Under development	Non-Renewable	WECC ADS
Out of California	Existing and under development	Renewable, Storage and Non-Renewable	WECC ADS

- The list of generators currently operational inside the CAISO is compiled from the CAISO Master Generating Capability List[5]. 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. The CAISO Master File also includes information related to dynamically scheduled generators. These generators are physically located outside of the CAISO but 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 renewable generators that will serve IOU-related CAISO load are compiled from the January 2019 version of the RPS contracts database maintained by CPUC staff and supplemented by data requests from CCAs and ESPs.
- For generators outside of CAISO, including areas within California such as IID, LADWP and SMUD, generator listings and their associated operating information are taken from WECC's 2028 Anchor Data Set (ADS) Phase 2 V1.2.

[5] Available at: http://oasis.caiso.com/mrioasis/logon.do

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 more accurately reflect different classes of gas generators associated with the CAISO BAA, CAISO's gas generators are further divided into subcategories, the three other California BAAs do not have this level of disaggregation of resources. The CAISO associated resources are grouped and differentiated into subcategories 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 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"**.
- 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 2020 to achieve compliance with the State Water Board's Once-Through-Cooling (OTC) regulations. Sensitivity analysis explores alternative retirement assumptions for OTC steam units.
- The **"CAISO_Reciprocating_Engine"** generator category represents existing gas-fired reciprocating engines on the CAISO system.
- The **"CHP"** generator category represents non-dispatchable cogeneration facilities with thermal hosts, which are modeled as firm resources in RESOLVE. "Firm" refers to around-the-clock power production at a constant level.

The capacity of fossil-fueled and nuclear thermal generators that have formally announced retirement are removed from baseline thermal capacity using the announced retirement schedule.

3.1.2 Economic Retention

In the RESOLVE version used in the CPUC 2017 IRP analysis, existing thermal resources were assumed to be available indefinitely unless retirement had already been announced. The version of the RESOLVE model used in this analysis has been updated to determine the optimal level of dispatchable gas resources to retain that minimizes overall California system costs.

Fixed operations and maintenance costs (fixed O&M) 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. Fixed O&M costs are derived from NREL's 2018 Annual Technology Baseline.[6]

- Retention decisions are made for CCGTs, Peakers, and Reciprocating Engines.
- Gas resources located in local capacity regions are retained to maintain local reliability (Section 7.3)
- Combined heat and power (CHP) facilities are all retired in 2035.
- OTC plants (CAISO_ST) are retired on a pre-determined schedule. Retention decisions for these plants are not made by RESOLVE.

Note that RESOLVE's thermal economic retention functionality assesses whether it is economic to retain gas capacity for California ratepayers, but does <u>not</u> assess whether gas capacity should retire. In addition, gas plant operators may choose to keep plants online without a long-term contract.

3.1.3 California Resources Associated with CAISO

Baseline natural gas, coal, and nuclear resources serving California loads within the CAISO BAA 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 WECC 2028 Anchor Data Set. All CAISO OTC capacity is retired by the end of 2023.

[6] https://atb.nrel.gov/electricity/2018/

Table 15. Baseline Conventional Resources in the CAISO balancing area (MW)

Resource Class	2027	2030	2035	2040	2045
CHP	2,296	2,296	1,148	-	-
Nuclear*	635	635	635	635	635
CCGT1	13,333	13,333	13,333	13,333	13,333
CCGT2	2,928	2,928	2,928	2,928	2,928
Coal**	-	-	-	-	-
Peaker1	4,914	4,914	4,914	4,914	4,914
Peaker2	3,683	3,683	3,683	3,683	3,683
Advanced CCGT	-	-	-	-	-
Aero CT	-	-	-	-	-
Reciprocating Engine	255	255	255	255	255
ST (NoOTCExtension Schedule)	-	-	-	-	-
Total	**28,044**	**28,044**	**26,896**	**25,748**	**25,748**

**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.*

*** Dedicated imports from the Intermountain Power Plant, located in Utah.*

3.1.4 Non-CAISO California Zones

For non-CAISO California Zones the baseline gas, coal, and nuclear generation fleet is based on the WECC 2028 ADS. The ADS is used to characterize the existing and anticipated future generation fleet in each non-CAISO associated resource. 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.

The combination of existing and planned thermal resources from all four California BAAs (CAISO, LADWP, BANC, IID) serve as the baseline thermal resource in this CEC SB100 analysis.

Table 16. Baseline conventional resources in non-CAISO California zones (MW)

Zone	Resource Class	2027	2030	2035	2040	2045
LADWP - Associated	Nuclear*	407	407	407	407	407
	Coal	-	-	-	-	-
	CCGT	2,755	2,755	2,755	2,755	2,755
	Peaker	1,647	1,647	1,647	1,647	1,647
	ST	371	197	197	197	197
	Subtotal, LADWP	**5,180**	**5,006**	**5,006**	**5,006**	**5,006**
IID - Associated	CCGT	255	255	255	255	255
	Peaker	327	327	397	327	327
	Subtotal, IID	**582**	**582**	**652**	**582**	**582**
BANC - Associated	CCGT	1,863	1,798	1,798	1,798	1,798
	Peaker	867	867	867	867	867
	Subtotal, BANC	**2,730**	**2,664**	**2,664**	**2,664**	**2,664**

3.1.5 Non-California, External Zones

For external zones (Northwest and Southwest), the baseline gas, coal, and nuclear generation fleet is based on the WECC 2028 ADS. The ADS is used to characterize the existing and anticipated future generation fleet in each associated resource. 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 17. Baseline conventional resources in non-California external zones (MW)

Zone	Resource Class	2027	2030	2035	2040	2045
NW	Nuclear	1,757	1,757	1,757	1,757	1,757
	Coal	8,126	7,364	7,364	7,364	7,364
	CCGT	9,573	9,573	9,573	9,573	9,573
	Peaker	2,993	2,993	2,993	2,993	2,993
	Subtotal, NW	**21,862**	**21,687**	**23,896**	**21,862**	**21,687**
SW	Nuclear*	2,998	2,998	2,998	2,998	2,998
	Coal	6,266	6,141	6,141	6,141	6,141
	CCGT	19,421	19,741	19,153	18,498	16,157
	Peaker	6,808	6,302	6,238	5,482	5,482
	ST	1,319	967	825	825	825
	Subtotal, SW	**33,813**	**33,150**	**31,783**	**33,813**	**33,150**

* In RESOLVE, Palo Verde is split between zones according to contractual ownership shares.

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, or ESP boards, as well as those under development, are included in the baseline, though these resources are discounted by 5 percent to allow for contract or project failure.

Baseline behind-the-meter solar capacity is discussed in Sections 2.1.5 and 2.2 above.

3.2.1 CAISO

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 contacts is compiled from the CPUC IOU contract database. 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 18.

Table 18. Baseline Renewables in CAISO (MW)

Resource Class	2027	2030	2035	2040	2045
Small Hydro	967	967	967	967	967
Biomass	937	935	935	935	935
Geothermal	1,896	1,896	1,896	1,896	1,896
Solar	14,990	14,990	14,990	14,990	14,990
Wind	8,649	8,649	8,649	8,649	8,649
Total	**27,439**	**27,437**	**27,437**	**27,437**	**27,437**

3.2.2 Non-CAISO California Zones

Similar to the thermal fleet, for non-CAISO entities in California (those in the BAA IID, LADWP or BANC), the renewable resource portfolio is derived from the 2028 WECC ADS. The analysis kept the planned renewable build constant beyond 2020. Baseline renewable capacities for other California entities are shown in Table 19.

Table 19. Baseline Renewables in Other California Entities (MW)

Zone	Resource Class	2027	2030	2035	2040	2045
BANC	Biomass	18	18	18	18	18
	Geothermal	-	-	-	-	-
	Small Hydro	41	41	41	41	41
	Solar	2,078	2,078	2,078	2,078	2,078
	Wind	-	-	-	-	-
	BANC Total	**2,136**	**2,136**	**2,136**	**2,136**	**2,136**
IID	Biomass	77	77	77	77	77
	Geothermal	709	709	709	709	709
	Small Hydro	-	-	-	-	-
	Solar	139	139	139	139	139
	Wind	-	-	-	-	-
	IID Total	**925**	**925**	**925**	**925**	**925**
LADWP	Biomass	-	-	-	-	-
	Geothermal	-	-	-	-	-
	Small Hydro	56	56	56	56	56
	Solar	2,411	2,411	2,411	2,411	2,411
	Wind	418	418	418	418	418
	LADWP Total	**2,885**	**2,885**	**2,885**	**2,885**	**2,885**

3.2.3 Non-California External Zones

The portfolios of renewable resources in the NW and SW are based on WECC's 2028 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 20.

Table 20. Baseline Renewables in non-California LSEs (MW)

Zone	Resource Class	2027	2030	2035	2040	2045
NW	Biomass	584	544	544	544	544
	Geothermal	142	142	132	132	132
	Small Hydro	41	41	41	41	41
	Solar	2,666	2,661	2,660	2,660	2,660
	Wind	11,057	10,956	10,956	10,956	10,956
	NW Total	**14,490**	**14,344**	**14,334**	**14,334**	**14,334**
SW	Biomass	113	108	108	108	108
	Geothermal	702	665	665	665	665
	Small Hydro	-	-	-	-	-
	Solar	1,855	1,831	1,652	1,647	1,637
	Wind	2,277	1,873	1,873	1,873	1,873
	SW Total	**4,947**	**4,477**	**4,297**	**4,292**	**4,282**

Resources that have a contract to supply RECs to a California LSE but are not dynamically scheduled into California are modeled as supplying RECs to California 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 21.

Table 21.Renewable plants outside of California attributed to California loads

Generator Name	Capacity Contracted to CAISO (MW)
Arlington Wind Power Project-GEN1	103
Big Horn Wind Project-1	105
Big Horn Wind II-1	18
NaturEner Glacier Wind Energy 1-NGW1	107
NaturEner Glacier Wind Energy 2-NGW2	104
Goshen Phase II-1_Jolly Hills	90
Goshen Phase II-2_Jolly Hills	39
Horse Butte Wind I, LLC-1	7
Horseshoe Bend Wind LLC-1 AKA Shepherds Flat - South	145
Juniper Canyon I Wind Project-1	5
Klondike Wind Power-Ph 1	24
Klondike Windpower III-1	90
Luning Solar Energy Project 1	55
Macho Springs Wind Farm GEN	50
Midway Solar Farm	50
Milford Wind Corridor Project 1A	5
Nippon Biomass-ST1	20
North Hurlburt Wind LLC-1 AKA Shepherds Flat	133
Pebble Springs Wind LLC-1	20
NaturEner Rim Rock Energy-RR	189
RooseveltBiogasCC (Total CC Plant)	26
Salton Sea Unit 5 TG51	50
Second Imperial Geothermal Company - Heber II 1-12	33
South Hurlburt Wind LLC-4 AKA Shepherds Flat	145
Tieton Dam Hydro Electric Project-UNIT1	7
Turquoise Solar	10
Vantage Wind Energy LLC-1	96

3.3 Large Hydro

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

A fraction of the total Pacific Northwest hydro capacity is made available to California as a directly scheduled import. In this CEC SB100 RESOLVE model, specified imports of hydro power from the Pacific Northwest are included as a baseline hydro resource and are dispatched on an hourly basis (Section 6.5.2). 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.[7] Annual specified imports (in GWh/yr) are converted to an installed capacity (MW) assuming the same capacity factor as historical record of overall NW Hydro (46%) – this is for modeling purposes and is not meant to reflect contractual obligations for capacity.

Table 22. Large Hydro Installed Capacity

Region	Total (MW)
BANC - Associated	2,724
CAISO – Associated	7,070
IID – Associated	84
LADWP – Associated	600
NW	31,478
NW Hydro for CAISO	2,852
SW	2,680

3.4 Energy Storage

3.4.1 Pumped Storage

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

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

Table 23. Existing pumped storage resources in CAISO

Unit	Capacity (MW)
Eastwood	200
Helms	1218
Lake Hodges	40
O'Neil	25.2
Other (WNDGPP)	116
Total	**1599**

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. Because of RESOLVE'S 24-hour dispatch window, the energy arbitrage value resulting from the capability to store energy for more than one day is not captured in RESOLVE.

3.4.2 Baseline Battery Storage

Baseline storage resources include all battery storage that is currently installed in the CAISO footprint, as well as further battery storage development that is likely to occur due to state policy mandate. Specifically, 1,285 MW of battery storage is modeled to fulfill the CPUC procurement targets established in response to AB 2514.[8] The remaining 40 MW of the total 1,325 MW of AB 2514 targets is the Lake Hodges Pumped Hydro project, which is included with pumped storage. Mandated battery storage capacity not already installed or contracted is allocated between wholesale (transmission and distribution interconnection domain) and behind-the-meter installations (customer-side) in-line with AB2514.

In addition to the mandated procurement amount, LSE responses to an April 2019 data request identified the following:

- Online dates and capacity, where IOUs have procured storage earlier than required by AB2514. For each IOU and each sub-domain, the greater of actual and mandated procurement is assumed.

[8] AB 2514 was signed into law on September 29, 2010. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514

- Additional behind-the-meter storage installations resulting from the Small Generator Incentive Program (SGIP) not already accounted for under other mandated procurement, including AB2514.
- Non-IOU storage procurement.

Based on the April 2019 data from LSEs, baseline utility scale storage resources are assumed to have an average duration of 4 hours. Baseline behind-the meter storage resources that are LSE-procured are assumed to have an average duration of 4 hours, with the remaining behind-the-meter storage resources assumed to have 2 hours duration.

Table 24. Baseline Battery Storage (MW)

Battery Storage Resource	2027	2030	2035	2040	2045
Utility-scale	1,617	1,617	1,617	1,617	1,617
Behind-the-meter	1,402	1,647	1,647	1,647	1,647

3.5 Demand Response

Shed (or “conventional”) demand response reduces demand only during peak demand events. The 2019-2020 IRP 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 for each utility’s programs is based on the April 1, 2018 Demand Response Load Impact Report.[9] As shown in Table 25, RESOLVE includes two options for baseline shed demand response capacity.

Table 25. Baseline Shed Demand Response (MW)

Scenario Setting	Region	2027	2030	2035	2040	2045
Reliability & Economic	PG&E	541	541	541	541	541
	SCE	1,019	1,019	1,019	1,019	1,019
	SDG&E	56	56	56	56	56

[9] CPUC Decision (D.)16-06-029, *Decision Adopting Bridge Funding for 2017 Demand Response Programs and Activities,* authorized PG&E and SDG&E to eliminate their Demand Bidding Program (DBP) starting in 2017, and SCE to eliminate its DBP program starting in 2018 (at p.43). D.16-06-029 also authorizes decreases in Aggregator Managed Portfolio (AMP) program capacity. The effects of these authorizations should be captured in the April 1, 2018, DR Load Impact Report.

Programs (default)	*Total*	*1,617*	*1,617*	*1,617*	*1,617*	*1,617*
	Total, with avoided losses	**1,752**	**1,752**	**1,752**	**1,752**	**1,752**
Reliability Programs Only	PG&E	330	330	330	330	330
	SCE	696	696	696	696	696
	SDG&E	7	7	7	7	7
	Total	*1,033*	*1,033*	*1,033*	*1,033*	*1,033*
	Total, with avoided losses	**1,119**	**1,119**	**1,119**	**1,119**	**1,119**

An additional 443 MW of interruptible pumping load from the CAISO NQC list is included as baseline shed DR capacity in all years.

4. Candidate Resources

"Candidate" resources represent the menu of new resource options from which RESOLVE can select to create an optimal portfolio. RESOLVE can add many different types of resources, including natural gas generation, renewables, energy storage, and demand response. 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.

4.1 Natural Gas

The CEC SB100 model includes three technology options for new natural gas generation: Advanced Combined Cycle (CCGT), Aeroderivative Combustion Turbine (CT), and Reciprocating Engine. Each option has different costs, efficiency, and operational characteristics. Natural gas generator all-in fixed costs trajectories are derived from NREL's 2019 Annual Technology Baseline[10] and the WECC capital cost study.[11] Natural gas fuel costs are discussed in Section 6.6. 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.

Table 26. All-in fixed costs for candidate natural gas resources in 2030 (2016$)

Resource Class	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)	All-In Fixed Cost ($/kW-yr)
CA_Advanced_CCGT	$1,205	$11.1	$122
CA_Aero_CT	$1,283	$13.6	$133
CA_Reciprocating_Engine	$1,283	$13.6	$133

4.2 Renewables

RESOLVE can select from the following candidate renewable resources:

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[10] https://atb.nrel.gov/electricity/2019/

[11] https://www.wecc.org/Administrative/E3-WECC%20Resource%20Cost%20Update-201905%20RAC%20DS%20Presentation.pdf

- Biomass
- Geothermal
- Small Hydro
- Solar Photovoltaic
- Onshore Wind
- Offshore Wind
- Hydrogen Fuel Cell

Candidate solar photovoltaic resources are represented as either utility-scale or distributed. Utility-scale and distributed solar resources differ in cost (Section 4.2.6.1), transmission (Section 4.2.7), and performance (Section 6.2) assumptions.

4.2.1 Resource Potential and Renewable Transmission Zones

Stakeholder feedback informed updates to the 2017-2018 CPUC IRP assumptions on the potential of candidate renewable resources, which were based on data developed by Black & Veatch for the CPUC's RPS Calculator v.6.3.[12] The Black & Veatch study includes an assessment of potentially viable sites and resource potential within those sites to determine an overall technical potential for each renewable technology.

The Black & Veatch study uses geospatial analysis to identify potential sites for renewable development in California and throughout the Western Interconnection. For input into RESOLVE, the detailed geospatial dataset developed by Black & Veatch is aggregated into "transmission zones." In the 2017-2018 CPUC IRP cycle, the transmission zones were expressed as groupings of Competitive Renewable Energy Zones (CREZs). These groupings have been updated for the 2019-2020 CPUC IRP cycle to incorporate CAISO's most recent transmission capability estimates.[13] Specifically, geospatial information on the extent of transmission constraints is used to assign individual wind, solar, and geothermal resources in the Black & Veatch dataset to a specific transmission zone or subzone. Individual resources within a transmission zone or subzone are aggregated, resulting in a "Base" resource potential for each

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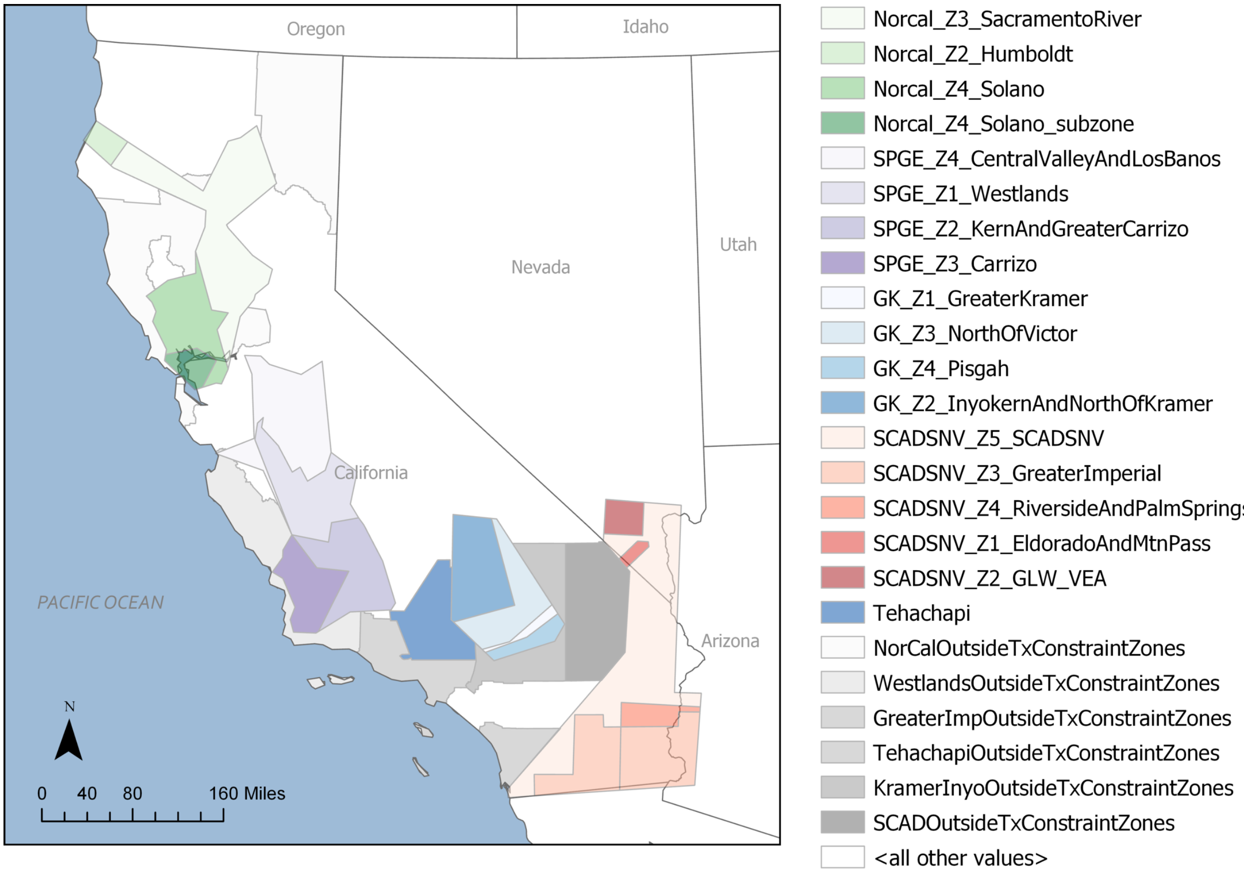
[12] Black & Veatch, *RPS Calculator V6.3 Data Updates*. Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/RPSCalc_CostPotentialUpdate_2016.pdf. Note that although the data was developed with the intention of incorporating it into a new version of the RPS Calculator, no version 6.3 was been developed. This is because the IRP system plan development process replaced the function previously served by the RPS Calculator.

[13] Transmission Capability Estimates for Inputs to the CPUC Integrated Resource Plan Portfolio Development. http://www.caiso.com/Documents/TransmissionCapabilityEstimates-Inputs-CPUCIntegratedResourcePlanPortfolioDevelopment-Call052819.html

zone-technology combination. This is maintained in this CEC SB100 model. The transmission zones are shown in Figure 4.1 below and described in Section 4.2.7.

Figure 4.1. In-state transmission zones in RESOLVE



Candidate biomass and distributed solar resources are not assigned a transmission zone because they are assumed to serve local load.

4.2.2 Environmental Screens

The raw technical potential estimates developed by Black & Veatch are filtered through a set of environmental screens to produce the potential available to RESOLVE (Table 27). The RESOLVE Scenario Tool includes several options for environmental screens, which were originally developed for the RPS Calculator:

- **Base:** includes RETI Category 1 exclusions only
- **Environmental Baseline (EnvBase):** includes RETI Category 1 and 2 exclusions
- **NGO1:** first screen developed by environmental NGOs
- **NGO1&2:** second screen developed by environmental NGOs

- **DRECP/SJV:** includes RETI Categories 1 and 2 plus preferred development areas only in the DRECP (Desert Renewable Energy Conservation Plan)[14] and San Joaquin Valley (SJV).
- **Conservative:** the potential when all the above screens are applied simultaneously

A more detailed explanation of each environmental screen is available in the Black & Veatch, RPS Calculator V6.3 Data Updates.[15]

In the 2017-2018 CPUC IRP, candidate solar capacity as calculated from Black and Veatch geospatial analysis was discounted by 95% to reflect land use constraints and preference for geographic diversity. This value has been updated to 80% in the 2019-2020 IRP because geographic diversity is largely enforced by transmission limits. As a result, the solar potential reflected in Table 27 is four times the 2017-2018 IRP values for most solar resources.

Adjustments are made to the supply curve potentials for certain resources under all environmental screens. In addition, planned resources with an online date after December 31, 2018 that are included in the baseline are subtracted from the available potential in the supply curve. Finally, reflecting commercial interest and recent CAISO interconnection queue capacity, 866 MW of Northern California wind resources are assumed available under all screens.

For this SB100 analysis the DRECP/SJV resource screen was used.

Table 27. California renewable potential under various environmental screens (MW)

Resource Type	Resource	Base	Env Base	NGO1	NGO1&2	DRECP/ SJV	Conservative
Biomass	InState_Biomass	1,147	1,147	1,147	1,147	1,147	1,147
Geothermal	Greater_Imperial	1,352	1,352	1,352	1,352	1,352	1,352
	Inyokern_North_Kramer	24	24	24	24	24	24
	Northern_California_Ex	469	469	469	469	469	469
	Riverside_Palm_Springs	32	32	32	32	32	32
	Solano	135	135	135	135	135	135
	Geothermal, subtotal	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**
Solar	Carrizo	12,021	9,842	11,939	5,867	9,907	5,867
	Central_Valley_North_Los_Banos	28,170	19,759	27,707	16,651	12,873	11,801
	Distributed	36,605	36,605	36,605	36,605	36,605	36,605
	Mountain_Pass_El_Dorado	1,152	60	1,152	41	248	41

[14] https://www.drecp.org/

[15] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/RPSCalc_CostPotentialUpdate_2016.pdf

	Greater_Imperial	27,759	18,632	27,366	17,714	35,216	14,455
	Inyokern_North_Kramer	7,697	4,804	7,695	4,751	23,653	4,009
	Kern_Greater_Carrizo	20,041	18,280	18,732	12,847	8,329	8,329
	Kramer_Inyokern_Ex*	8,484	6,138	8,409	6,134	4,508	4,508
	North_Victor	6,992	5,886	6,949	5,779	4,608	4,256
	Northern_California_Ex	68,912	41,306	67,698	33,367	41,532	33,367
	Riverside_Palm_Springs	11,777	5,711	11,757	5,396	57,071	5,396
	Sacramento_River	28,684	23,260	27,346	19,784	23,484	19,784
	SCADSNV	10,224	3,121	10,122	3,076	5,608	2,162
	Solano	16,588	11,937	15,521	9,724	12,025	9,724
	Solano_subzone	-	4	-	4	-	-
	Southern_California_Desert_Ex	6,290	3,067	6,230	2,944	43,713	566
	Tehachapi_Ex*	2,202	1,487	2,168	1,481	1,488	1,481
	Tehachapi**	17,650	13,480	17,363	13,294	3,801	3,801
	Westlands_Ex_Solar	5,358	4,394	5,304	4,269	4,404	4,269
	Westlands_Solar	26,671	24,705	26,305	22,599	56,151	22,599
	Solar, subtotal	343,277	254,184	338,214	223,991	385,224	193,020
Wind	Carrizo	288	288	288	244	287	244
	Central_Valley_North_Los_Banos	398	173	352	91	173	91
	Distributed	-	-	-	-	-	-
	Greater_Imperial	785	-	782	-	-	-
	Greater_Kramer	445	80	389	80	-	-
	Humboldt	34	34	34	34	34	34
	Kern_Greater_Carrizo	69	60	69	60	60	60
	Kramer_Inyokern_Ex*	81	-	77	-	-	-
	Northern_California_Ex	866	866	866	866	866	866
	SCADSNV	100	-	96	-	-	-
	Solano_subzone	50	18	46	1	18	1
	Solano	576	550	524	453	542	445
	Southern_California_Desert_Ex	48	48	48	48	-	-
	Tehachapi	802	583	791	572	275	273
	Westlands_Ex	-	-	-	-	-	-
	Wind, subtotal	**4,542**	**2,700**	**4,361**	**2,448**	**2,255**	**2,013**

**Reflecting commercial interest, resource potential was removed via transmission limits*

*** Displayed Tehachapi solar potential reflects a 1 GW increase to pure land use screening due to more availability on transmission network*

4.2.3 Out of State Resource Potential

The available potential for out-of-state resources relies primarily on Black & Veatch's assessment of renewable resource potential that identifies "high-quality" resources in Western Renewable Energy Zones (WREZs). WREZ resource potential is aggregated into regional bundles to create candidate out-of-state renewable resources for RESOLVE. Some of these resources are assumed to require investments in new transmission to deliver to California loads. These estimates of resource potential are supplemented with assumptions regarding the availability of lower capacity factor renewables that may be interconnected on the existing transmission system.

To explore different levels of out-of-state resource availability, the CEC SB100 model includes two “screens” for out-of-state resources[16]:

- **None:** no candidate out-of-state resources are included except for Baja California wind, Southern Nevada wind and solar, and Arizona solar resources that directly connect to the CAISO transmission system.
- **Existing & NM/WY wind:** New Mexico and Wyoming out-of-state wind resources requiring major investments in new transmission, are included as candidate resources.

The amount of renewable potential included under each screen is summarized in Table 28. All estimates of potential shown in this table—with the exception of resources assumed to interconnect to the existing transmission system—are based on Black & Veatch’s potential assessment. The Existing & NM/WY wind screen is the default screen for the CEC SB100 analysis, however the default potential of out-of-state wind is limited to 12,000 MW (6,000 MW of Wyoming and 6,000 MW of New Mexico wind resources) to reflect the likelihood that two double-circuit large high-voltage transmission lines (~3,000 MW each) to each of these wind resources could be built.

Reflecting commercial interest and recent CAISO interconnection queue capacity, 600 MW of Baja California wind resources, and all of the Arizona solar potential, are available for selection in all model runs.

[16] Information regarding individual land use screens is available in the Renewable Energy Transmission Initiative 2.0 Plenary Report. https://www.energy.ca.gov/reti/reti2/documents/index.html

Table 28. Out-of-state renewable potential under various scenario settings

Type	Resource	Renewable Potential (MW)	
		None	Existing & NM/WY wind
Geothermal	Southern Nevada	320	320
	Subtotal, Geothermal	**320**	**320**
Solar	Arizona	77,080	77,080
	New Mexico	—	—
	Southern Nevada	148,600	148,600
	Utah	—	—
	Subtotal, Solar	**225,680**	**225,680**
Wind	Arizona	—	—
	Baja California	600	600
	Idaho	—	—
	New Mexico (Existing Tx)	—	500
	New Mexico	—	6,000 (Limited)
	Pacific Northwest (Existing Tx)	—	1,500
	Pacific Northwest	—	—
	Southern Nevada	442	442
	Utah	—	—
	Wyoming	—	6,000 (Limited)
	Subtotal, Wind	**1,042**	**15,042 (Full)**

4.2.4 Offshore Wind Resource Potential

Data for offshore wind potential is sourced from the UC Berkeley study California Offshore Wind: Workforce Impacts and Grid Integration.[17] The report identifies offshore wind resource zones based on existing BOEM call areas for California, as well as potential future development sites identified in studies by BOEM and NREL. In this study, offshore wind availability is limited to 10 GW over four resource zones: Morro Bay, Diablo Canyon, Humboldt Bay, and Cape Mendocino. The offshore wind resource potential assumptions are shown below.

Table 29. Offshore Wind Resource Potential

Offshore Wind Resource Zone	Resource Potential Area (Sq. km)	Resource Potential (MW)
Cape Mendocino	2,072	6,216 (Full) 1,649 (Limited)
Diablo Canyon	1,441	4,324
Morro Bay	806	2,419
Humboldt Bay	536	1,607
Total	**4,855**	**14,566 (Full)** **10,000 (Limited)**

Note that the offshore resource potential shown in Table 29 represents that amount that could be developed offshore.

4.2.5 First Available Year and Annual Deployment Limits

Assumptions for the first available year of candidate renewables resource types reflect feasible timelines for bringing resources online based on the current interconnection queue and typical development timelines. The first available year in RESOLVE is applied on a resource-by-resource basis; accordingly, a range of years applies when summarizing by resource type in Table 30.

Table 30. First available year by candidate renewable resource type

Resource Type	First Available Year
Solar PV	2020

[17] Available at: http://laborcenter.berkeley.edu/offshore-wind-workforce-grid/

Wind (CA onshore)	2022-2023
Wind (OOS onshore)	2026
Wind (offshore)	2030
Geothermal	2024-2026
Biomass	2020
Pumped Storage	2026
Battery Storage	2020

In addition to limiting the deployment of resources based on the first available year, RESOLVE can also enforce annual deployment limits over a group of resources.

4.2.6 Resource Cost

NREL's 2019 Annual Technology Baseline is used as the primary basis for renewable generation cost updates.[18] Hydrogen fuel cell cost estimates are based on the US Department of Energy 2020 technical targets for fuel cell systems[19] and cost trajectories in the E3 study "The Challenge of Retail Gas in California's Low-Carbon Future" for the CEC.[20] 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 ($/kW-yr) for each resource; this is translated into the levelized cost of energy ($/MWh) for comparability with typical Power Purchase Agreements (PPA) entered into between LSEs and third-party developers.

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[18] Biomass capital costs were revised from Annual Technology Baseline assumptions based on stakeholder input

[19] US Department of Energy Fuel Cell Technologies Office. 2017. *Multi-Year Research, Development, and Demonstration Plan. 3.4 Fuel Cells.* https://www.energy.gov/sites/prod/files/2017/05/f34/fcto_myrdd_fuel_cells.pdf. Table 3.4.14.

[20] Assuming off-grid California wind or solar to power the electrolyzer, with electrolyzer costs and trajectories developed by the University of California at Irvine (UCI) for the E3 study "The Challenge of Retail Gas in California's Low-Carbon Future" for the California Energy Commission:
Aas, Dan, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, and Snuller Price. 2020. *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. Appendix C.* California Energy Commission. Publication Number: CEC-500-2019-055-AP-G. https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-AP-G.pdf.

Table 31. California renewable resource cost & performance assumptions

	Resource	Capacity Factor	Implied Levelized Cost of Energy (2016 $/MWh) 2027	2030	2035	2040	2045
Biomass	InState_Biomass	85%	$128	$128	$128	$128	$127
Geothermal	Greater_Imperial_Geothermal	88%	$79	$79	$78	$77	$76
	Inyokern_North_Kramer_Geothermal	80%	$87	$87	$86	$85	$83
	Northern_California_Ex_Geothermal	81%	$86	$85	$85	$84	$82
	Riverside_Palm_Springs_Geothermal	80%	$87	$87	$86	$85	$83
	Solano_Geothermal	90%	$77	$77	$76	$75	$74
Solar *(solar capital costs shown in $/kW-ac)*	Carrizo_Solar	31%	$29	$27	$26	$25	$23
	Central_Valley_North_Los_Banos_Solar	29%	$31	$29	$28	$26	$25
	Distributed_Solar	21%	$52	$48	$46	$45	$42
	Greater_Imperial_Solar	31%	$29	$27	$26	$25	$23
	Inyokern_North_Kramer_Solar	32%	$28	$26	$25	$24	$23
	Kern_Greater_Carrizo_Solar	31%	$29	$27	$26	$25	$23
	Kramer_Inyokern_Ex_Solar	32%	$28	$26	$25	$24	$23
	North_Victor_Solar	32%	$28	$26	$25	$24	$23
	Northern_California_Ex_Solar	28%	$32	$30	$29	$27	$26
	Riverside_Palm_Springs_Solar	31%	$29	$27	$26	$25	$23
	Sacramento_River_Solar	28%	$32	$30	$29	$27	$26
	SCADSNV_Solar	31%	$29	$27	$26	$25	$23
	Solano_Solar	29%	$31	$29	$28	$26	$25
	Solano_subzone_Solar	29%	$31	$29	$28	$26	$25
	Southern_California_Desert_Ex_Solar	31%	$29	$27	$26	$25	$23
	Tehachapi_Ex_Solar	32%	$28	$26	$25	$24	$23
	Tehachapi_Solar	32%	$28	$26	$25	$24	$23

	Westlands_Ex_Solar	31%	$29	$27	$26	$25	$23
	Westlands_Solar	31%	$29	$27	$26	$25	$23
Wind	Carrizo_Wind	31%	$46	$44	$43	$41	$40
	Central_Valley_North_Los_Banos_Wind	31%	$46	$44	$43	$41	$40
	Greater_Imperial_Wind	34%	$42	$40	$39	$38	$36
	Greater_Kramer_Wind	31%	$46	$44	$43	$41	$39
	Humboldt_Wind	29%	$49	$47	$46	$44	$42
	Kern_Greater_Carrizo_Wind	31%	$46	$44	$43	$41	$40
	Kramer_Inyokern_Ex_Wind	31%	$46	$44	$43	$41	$40
	Northern_California_Ex_Wind	29%	$49	$47	$46	$44	$42
	SCADSNV_Wind	30%	$48	$45	$44	$43	$41
	Solano_subzone_Wind	30%	$48	$45	$44	$43	$41
	Solano_Wind	30%	$48	$45	$44	$43	$41
	Southern_California_Desert_Ex_Wind	30%	$48	$45	$44	$43	$41
	Tehachapi_Wind	34%	$42	$40	$39	$38	$36

Table 32. Hydrogen Fuel Cell Cost Assumptions

Hydrogen Fuel Cell Cost Assumptions	2027	2030	2035	2040	2045
Capital Cost ($/kW)	$1,381	$1,290	$1,187	$1,026	$917
Fixed O&M Cost ($/kW-yr)	$27	$27	$27	$27	$27
All-in Fixed Cost ($/kW-yr)	$138	$131	$123	$110	$101

Table 33. Out-of-state renewable resource cost & performance assumptions. Costs in this table do not include the incremental cost of new, long distance transmission lines.

Resource	Capacity Factor	Implied Levelized Cost of Energy (2016 $/MWh) 2027	2030	2035	2040	2045
Pacific_Northwest_Geothermal	84%	$94	$94	$94	$93	$91
Southern_Nevada_Geothermal*	80%	$84	$84	$83	$82	$81
Arizona_Solar*	31%	$28	$26	$25	$24	$23
New_Mexico_Solar	30%	$74	$72	$71	$70	$69
Utah_Solar	29%	$57	$55	$54	$52	$51
Southern_Nevada_Solar*	31%	$28	$26	$25	$24	$23
Arizona_Wind	30%	$58	$56	$54	$53	$51
Baja_California_Wind*	36%	$39	$37	$36	$34	$33
Idaho_Wind	32%	$89	$87	$86	$85	$83
New_Mexico_Wind	44%	$63	$61	$60	$59	$58
NW_Ext_Tx_Wind	30%	$63	$60	$59	$58	$56
Pacific_Northwest_Wind	32%	$90	$88	$86	$85	$83
SW_Ext_Tx_Wind	36%	$65	$63	$62	$61	$59
Utah_Wind	31%	$70	$68	$67	$66	$64
Wyoming_Wind	44%	$69	$67	$66	$65	$64
Southern_Nevada_Wind*	28%	$50	$48	$46	$45	$43

**Assumed to directly interconnect to California*

Table 34. Offshore wind resource cost & performance assumptions. Only 2030 costs are used in RESOLVE because offshore wind is available for selection starting in 2030.

		Implied Levelized Cost of Energy (2016 $/MWh)				
Resource	Capacity Factor	2027	2030	2035	2040	2045
Humboldt_Bay_Offshore_Wind	52%	$85	$75	$62	$50	$43
Morro_Bay_Offshore_Wind	55%	$77	$69	$57	$47	$41
Diablo_Canyon_Offshore_Wind	46%	$92	$82	$68	$57	$48
Cape_Mendocino_Offshore_Wind	53%	$89	$79	$66	$53	$46

4.2.6.1 Solar Capital Cost Assumptions

The NREL Annual Technology Baseline "Mid" case projection 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 Annual Technology Baseline data.

The Annual Technology Baseline's solar 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. Consistent with current industry practice, cost calculations assume a single-axis tracking system with a 1.35 inverter loading ratio for utility-scale solar and a fixed-tilt system with 1.35 inverter loading ratio for distributed solar. The inverter loading ratio measures the amount of DC solar cells per the inverters rated AC output. For example, a 10 MW-AC inverter would typically be used for a solar system with 13.5 MW-DC of photovoltaics.

Solar O&M is estimated based on an average ratio of O&M to capital expenditure (CAPEX) reported in the Annual Technology Baseline. This treatment implicitly assumes that the same historical correlations seen in O&M and CAPEX cost reductions will hold into the future.

4.2.6.2 Wind Capital Cost Assumptions

NREL's 2018 Annual Technology Baseline "Mid" case also provides estimates of onshore wind costs. The Annual Technology Baseline develops regional sets of CAPEX values for a full range of observed wind speeds, resulting in a total of 10 bins, or "techno-resource groups" (TRGs). Zones with lower wind speeds are assumed to employ higher rotors to compensate, and therefore correspond to a higher CAPEX per MW of installed capacity. TRGs that resemble California and out-of-state wind conditions are used in the CEC SB100 analysis. As for solar, the Annual Technology Baseline provides base CAPEX and O&M values for wind, as well as three cost trajectories: Low, Mid, and Constant. The Annual Technology Baseline's estimates of the O&M of wind do not include regional variants and are assumed to be the same at all locations. NREL notes significant uncertainty in its estimation of wind O&M costs, largely due to limited publicly available data and the tendency for wind O&M to vary significantly by project due to vintage, capacity, location.

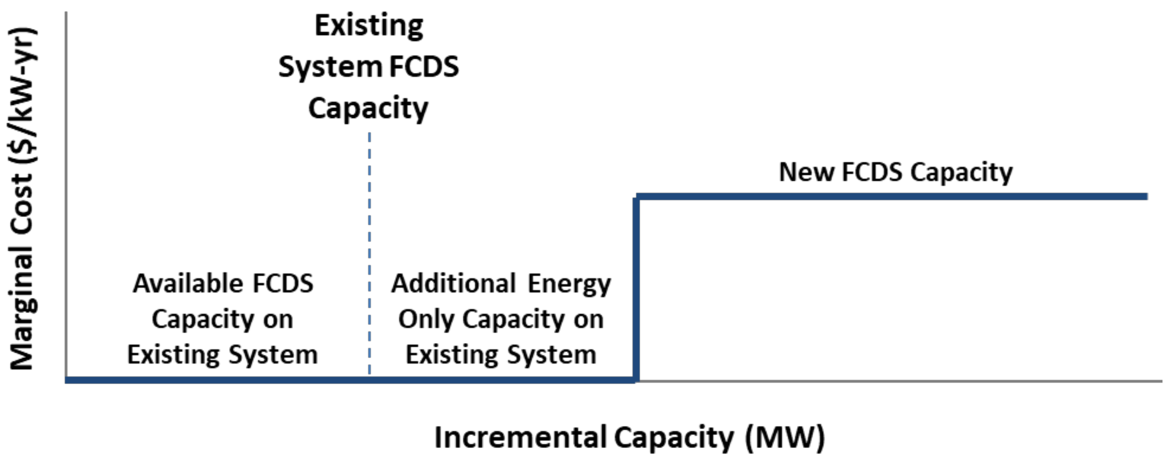
4.2.7 California Transmission Cost & Availability

Candidate renewable resources in RESOLVE are selected as **fully deliverable (Full Capacity Deliverability Status, or FCDS)** resources or **energy only (Energy Only Deliverability Status, or EO)** resources, each representing a different classification of deliverability status by CAISO. A resource with FCDS is included in RESOLVE's resource adequacy constraint and is 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.

In each transmission zone, RESOLVE selects resources in three categories:

- **FCDS resources on the existing system.** Each transmission zone is characterized by the amount of new resource capacity that can be installed on the existing system while still receiving full capacity deliverability status. Renewables within each transmission zone compete with one another for existing, zero marginal cost FCDS transmission capacity. RESOLVE will typically prioritize FCDS for resources with a higher resource adequacy contribution.
- **EO resources on the existing system.** Each transmission zone is also characterized by the amount of incremental energy-only capacity that can be installed beyond the FCDS limits (i.e. this quantity is additive to the FCDS limit). For each renewable resource, RESOLVE can choose for it to have EO status on the existing transmission system if EO capacity is available. In this case, the renewable resource does not contribute to the planning reserve margin.
- **FCDS resources on new transmission.** Resources in excess of the limits of the existing system may be installed but require investment in new transmission. This may occur (1) if both the FCDS and EO limits are reached; or (2) if the FCDS limit is reached and the value of new capacity exceeds the cost of the new transmission investment.

Figure 4.2. Conceptual diagram of transmission costs and capacity for candidate renewable resources in RESOLVE



RESOLVE does not currently include the option to upgrade the transmission system to increase the energy only capacity of a transmission zone.

Candidate distributed solar and wind resources are assumed to be fully deliverable on the existing transmission system and do not incur additional transmission costs. These resources are assigned a transmission zone of "None."

CAISO has produced transmission capability and cost estimates.[21] CAISO's whitepaper includes a table with a list of electrical zones, transmission capability estimates of the existing transmission system, and the cost and capacity of potential upgrades. CAISO's estimates are adjusted for use in RESOLVE (Table 36) by:

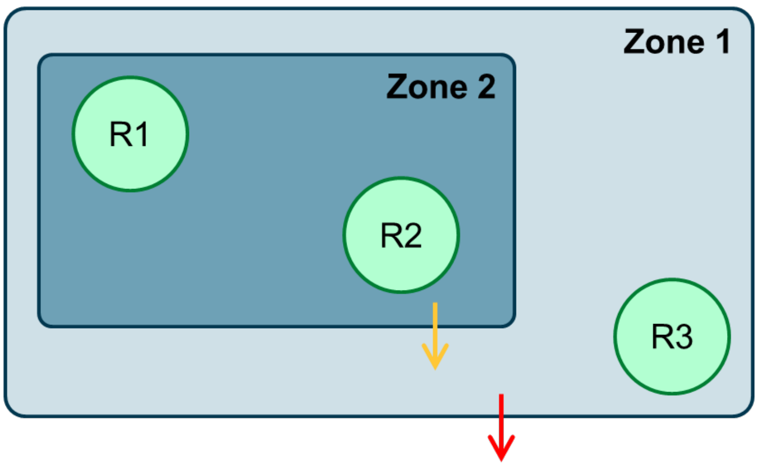
- Subtraction of baseline resource capacity that is projected to come online in 2019 or later from CAISO's transmission capability estimates. Resources brought online after 2018 must be allocated incremental transmission capacity because CAISO's transmission capability values include all resources online at the end of 2018.
- Conversion of upgrade cost and upgrade capacity into levelized, $/kW-yr values that are consistent with the "nested" transmission constraint formulation in RESOLVE (described

[21] http://www.caiso.com/Documents/TransmissionCapabilityEstimates-Inputs-CPUCIntegratedResourcePlanPortfolioDevelopment-Call052819.html

below). RESOLVE does not impose limitations on the size of new transmission investments.

In the whitepaper CAISO identifies multiple layers of transmission constraints for many transmission zones. These “nested” constraints represent multiple concurrent limitations to delivering energy from renewable resource zones to load centers (Figure 4.3). 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, nested constraints are modeled by allowing candidate resources to be assigned to multiple (nested) transmission zones. By allowing multiple assignments, a candidate resource counts towards the FCDS and EO limits in *all* of the zones and subzones to which it is assigned.

Figure 4.3. Diagram of nested transmission constraints



Transmission upgrade costs from the CAISO whitepaper are implemented in RESOLVE using the incremental cost to upgrade transmission from inner nested zone to the next outer nest, thereby creating a “layer cake” of transmission upgrade costs to access the wider CAISO transmission system. For example, in Figure 4.3, resources R1 and R2 contribute to the existing FCDS capability limit (or energy only limit) for both Zone 1 and Zone 2. Resource R3 only contributes to the corresponding limits for Zone 1. Selecting resources R1 and R2 may trigger an upgrade (illustrated with a yellow arrow pointing from Zone 2 to Zone 1) to increase deliverability into the next constrained layer (Zone 1). Separately, all three resources may trigger a transmission upgrade to ensure deliverability out of Zone 1 into the rest of the CAISO system (the red arrow pointing out of Zone 1). If it is necessary to upgrade both transmission lines (yellow and red arrows) to deliver capacity from R1 or R2 to the rest of the CAISO system, the sum of the cost to build capacity along the yellow and red arrows is incurred.

Table 36 includes the incremental cost to build new FCDS transmission. For subzones that are within another zone, this is the cost to build transmission to the next zone level (from right to left on Table 35). For zones that are an outermost transmission zone, the incremental cost is equal to the total cost to build new FCDS transmission because only one upgrade is required to reach load centers. For zones that are not an outermost transmission zone, transmission costs may be incurred at multiple levels of transmission zones. The nested zone formulation also applies for FCDS and EO availability on existing transmission in Table 35 – for resources that are in a subzone, transmission capacity must also be reserved in all outer zones.

Table 35. RESOLVE transmission zone "nested" hierarchy

<table>
<tr><th>Outermost Transmission Zone</th><th>Subzone Level 1</th><th>Subzone Level 2 (Innermost)</th></tr>
<tr><td rowspan="4">Southern CA Desert and Southern Nevada
(SCADSNV)</td><td>Mountain_Pass_El_Dorado
(Eldorado/Mtn Pass)</td><td>-</td></tr>
<tr><td>GLW_VEA
(Southern Nevada)</td><td>-</td></tr>
<tr><td>Greater_Imperial
(Greater Imperial)*</td><td>-</td></tr>
<tr><td>Riverside_Palm_Springs
(Riverside East & Palm Springs)*</td><td>-</td></tr>
<tr><td rowspan="2">SPGE (Southern PG&E)**</td><td>Kern_Greater_Carrizo
Kern and Greater Carrizo)</td><td>Carrizo (Carrizo)</td></tr>
<tr><td>Central_Valley_North_Los_Banos
(Central Valley North & Los Banos)</td><td>-</td></tr>
<tr><td rowspan="2">Greater_Kramer
(Greater Kramer (North of Lugo))***</td><td>North_Victor
(North of Victor)</td><td>-</td></tr>
<tr><td>Inyokern_North_Kramer
(Inyokern and North of Kramer)</td><td>-</td></tr>
<tr><td rowspan="2">Sacramento_River
(Northern CA/Sacramento River)</td><td>Solano (Solano)</td><td>Solano Subzone
(Solano_subzone)</td></tr>
<tr><td>Humboldt (Humboldt)</td><td>-</td></tr>
<tr><td>Tehachapi (Tehachapi)</td><td>-</td><td>-</td></tr>
<tr><td>Cape_Mendocino****</td><td></td><td>-</td></tr>
<tr><td>Kramer_Inyokern_Ex</td><td colspan="2" rowspan="5">"_Ex" zones have an available transmission capacity equal to the active capacity in CAISO's interconnection queue but are outside of CAISO's defined transmission zones. The "_Ex" zones do not have subzones in RESOLVE.</td></tr>
<tr><td>Northern_California_Ex</td></tr>
<tr><td>Southern_California_Desert_Ex</td></tr>
<tr><td>Tehachapi_Ex</td></tr>
<tr><td>Westlands_Ex</td></tr>
<tr><td>None</td><td colspan="2">The "None" zone bypasses transmission zone limitations, giving resources in this "zone" unlimited fully deliverable transmission. Only appropriate for distributed resources, and/or resources that serve local load. This zone does not have any subzones.</td></tr>
</table>

CAISO zone or sub-zone name shown in parentheses. Notes:

* CAISO identifies overlap between the Greater Imperial and Riverside East & Palm Springs transmission zones. RESOLVE models resources in this overlapping area within Greater Imperial but not Riverside East & Palm Springs because transmission availability of the Greater Imperial zone is more limiting.

** To adapt CAISO transmission constraint data into a format that is compatible with the RESOLVE nested constraint formulation, The Westlands subzone identified by CAISO is split between two zones in RESOLVE: 1) Kern and Greater Carrizo and 2) Central Valley North & Los Banos. The Westlands_Ex zone is used for resource capacity outside of the geographical extent of CAISO's Westlands zone.

*** Pisgah zone not modeled in RESOLVE due to a lack of candidate resources.

**** The Cape Mendocino zone was created for the purpose of modeling the Cape Mendocino offshore wind resource. This zone is not one of the CAISO zones

Table 36. Transmission availability & cost in CAISO

Transmission Zone or Subzone	Incremental Deliverability Cost ($/kW-yr)	FCDS Availability on Existing Transmission, Net of Post-2018 COD Baseline Capacity (MW)	Energy-Only Availability on Existing Transmission (MW, Default) ***	Energy-Only Availability (MW, Sensitivity) ****
Carrizo	$10	187	0	700
Central_Valley_North_Los_Banos	$36	791	0	500
GLW_VEA	$14	596	0	1470
Greater_Imperial	$221	919	1900	1900
Greater_Kramer	$48	597	0	0
Humboldt	$999**	0	100	100
Inyokern_North_Kramer	$161	97	0	0
Kern_Greater_Carrizo	$21	784	700	3680
Kramer_Inyokern_Ex*	$999**	0	0	0
Mountain_Pass_El_Dorado	$7	250	2150	3790
None	$0	0	0	0
North_Victor	$161	300	0	0
Northern_California_Ex*	$999**	866	0	0
Riverside_Palm_Springs	$88	2665	2550	3100
OffshoreWind_UnknownCost	$999**	0	0	0
Sacramento_River	$19	1995	2600	2600
SCADSNV	$102	2434	6600	10260
Solano	$21	599	700	700
Solano_subzone	$999**	0	0	0
Southern_California_Desert_Ex*	$999**	862	0	0
SPGE	$7	675	700	4080
Tehachapi	$13	3677	800	1800
Cape_Mendocino	$68*****	0	0	0
Tehachapi_Ex*	$999**	0	0	0
Westlands_Ex*	$999**	1779	0	0

* Resources that end in "Ex" refers to areas outside of the CAISO transmission cost and availability estimates

** $/999 kW-yr indicates that the upgrade cost is unknown, so an extremely high value is placed on transmission upgrades.

*** Zero is assumed by default for zones where Estimated EO Capability is noted as “TBD” in CAISO’s whitepaper, except for the Kern_Greater_Carrizo subzone (and SPGE zone), which include 700 MW of EO capability from CAISO’s “Tx Capability Estimates for 2019-2020 TPP”.

**** Energy Only capacity is expanded in several zones using data provided by CAISO staff to CPUC staff informally in November 2019 for the purpose of developing a TPP Policy-driven Sensitivity portfolio with a higher Energy Only resource buildout. This data is available in Table 7 of “CPUC Staff Report: Modeling Assumptions for 2020-2021 TPP Release 1, February 21, 2020”.

***** Transmission deliverability cost for Cape Mendocino estimated using WECC Tx Cost Calculator, for 500 kV transmission along existing Tx paths from Eureka to Redding. This cost is added to the Sacramento River zone deliverability cost to obtain a total deliverability cost. The cost of a new substation in Eureka is also included; was estimated based on 2020 PG&E Unit Costs.

Table 37. Aggregated transmission capability of Ex zones

Ex Zone	Partial County	FCDS Availability on Existing Transmission (MW)
NorCalOutsideTxConstraintZones	ColusaCounty_Partial LassenCountyPartial MarinCountyPartial MendocinoCountyPartial ModocCountyPartial SacramentoCountyPartial SanMateoCountyPartial SonomaCountyPartial TehamaCountyPartial YoloCountyPartial	877.9
TehachapiOutsideTxConstraintZones	LosAngelesCountyPartial VenturaCountyPartial	1870
WestlandsOutsideTxConstraintZones	MontereyCountyPartial SantaBarbaraCountyPartial SanLuisObispoCountyPartial	1781.7
SCADOutsideTxConstraintZones	SanBernardinoCountyPartial_E	862
KramerInyoOutsideTxConstraintZones	SanBernardinoCountyPartial_W	862
GreaterImpOutsideTxConstraintZones	SanDiegoCountyPartial	524.6

4.2.8 Out-of-State Transmission Cost

New out-of-state resources delivered to the California system are attributed an additional transmission cost, representing either the cost to wheel power across adjacent utilities' electric systems (for resources delivered on existing transmission) 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 cost of new transmission lines are based on assumptions developed for the CEC's Renewable Energy Transmission Initiative 2.0 (RETI 2.0).[22]

Table 38. Transmission costs for out-of-state resources

Zone	Existing Transmission Cost ($/kW-yr)	New Transmission Cost ($/kW-yr)
Arizona*	—	$29
Idaho	—	$129
New Mexico Tranche 1	$72	$103
New Mexico Tranche 2	—	$121
Northwest	$34	$99
Utah	—	$69
Wyoming Tranche 1	—	$113
Wyoming Tranche 2	—	$125

*Applicable only to Arizona wind because new Arizona solar is modeled as directly interconnecting to the CAISO system.

Resources that require new transmission to reach California are assumed to be delivered to a specific CAISO transmission zone or subzone. 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 38, plus any additional cost to develop transmission in CAISO transmission zones and/or subzones (Section 4.2.7) if the capacity of the existing CAISO transmission system is not sufficient. For New Mexico and Wyoming resources, the CEC

[22] https://www.energy.ca.gov/reti/

developed transmission cost estimates which are used as tranche 1 for the respective resource areas.

4.3 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: capacity ($/kW) and duration ($/kWh). The capacity cost refers to all costs that scale with the rated installed power (kW) while the duration costs refers to all costs that scale with the energy of the storage resource (kWh). 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 costs and relate to the costs of the turbines, the penstocks, the interconnection, etc., while duration costs are relatively small and mainly cover the costs of preparing a reservoir. For Lithium Ion (Li-ion) batteries, the capacity costs mainly relate to the cost of an inverter and other power electronics for the interconnection, while the duration costs relate to Li-ion battery cells. For flow batteries, the capacity costs relate to the cost of an inverter and other power electronics, as well as the ion exchange membrane and fluids pumps, while the duration costs mainly relate to the tanks and the electrolyte. As a result, the capacity component of flow battery costs is higher than that of Li-ion, while the duration component is lower.

4.3.1 Pumped Storage

The capital costs of candidate pumped storage resources for the CEC SB100 analysis are based on *Lazard's Levelized Cost of Storage 2.0* (2016).[23] Pumped storage costs are assumed to remain constant in real terms. Candidate pumped storage resources must have at least 12 hours of duration.

[23] Later releases of Lazard do not include pumped storage costs. Available at: https://www.lazard.com/perspective/levelized-cost-of-storage-analysis-20/. E3 used the average of the range provided in p. 31 of the Appendix. For the breakout of power to energy cost, E3 used the specified duration (8-hours) and assumed energy costs per kWh are 1/10th of the power costs per kW.

Table 39. Pumped storage cost components

Cost Component	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)
Capital Cost ($/kW)	$2,511	$25

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

- Financing lifetime of 50 years
- Fixed O&M of $25/kW-yr with an annual escalation of 2%
- No variable O&M costs
- After-tax WACC of 7.24% (in 2030).

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

Table 40. Pumped storage all-in levelized fixed costs.

Cost Component	2027	2030	2035	2040	2045
Levelized Cost ($/kW-yr)	$190	$192	197	$199	$200

The pumped storage resource potential assumptions are shown in the table below.

Table 41. Available potential by year (MW) for candidate pumped storage resources.

Resource Class	2020	2022	2026	2030	2035	2040	2045
Potential (MW)	-	-	4,000	4,000	4,000	4,000	4,000

4.3.2 Battery Storage

Battery storage costs are attributed to either the capacity or duration category using AC and DC storage component cost data and comparisons of storage costs at differing durations.[24] 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.

[24] Duration costs are considered to include all costs in Lazard's "Initial capital cost - DC" category, whereas capacity costs include both "Initial capital cost – AC" and "Other Owners Costs."

- Duration (kWh): Battery cell modules, racking frame/cabinet, battery management system.

The total cost of an energy storage system is calculated by summing the cost for each capacity and duration “building block.” Reflecting the hourly dispatch interval used in RESOLVE, candidate battery storage resources must have at least 1 hour of duration.

The CEC SB100 model includes both wholesale and Behind-The-Meter (BTM) battery storage as candidate resources and relies on storage cost assumptions from Lazard’s Levelized Cost of Storage 5.0 (2019) and supplemented by NREL’s Solar and Storage Report.[25, 26] Cost assumptions for candidate wholesale storage are derived from Lazard’s peaker replacement use case using the methodology described above. Both Li-ion and Flow technologies are included as candidate wholesale battery storage resources. While paired battery technologies are not explicitly modeled in RESOLVE, paired battery storage can be represented with a separate cost trajectory that includes ITC benefits and other co-location cost savings. Candidate BTM battery storage is assumed to be Li-ion technology, with costs derived from Lazard’s commercial use case for Li-ion.

In addition to breaking out capital costs between capacity and duration, different O&M costs are attributed to each of these categories. For example, warranty and augmentation costs are assumed to cover battery cell performance, thus are attributed to the duration category.

Forecasts for storage cost declines are based on Lazard through 2022, the last year of the Lazard forecast. After 2022, it is assumed the pace of cost reductions slows to zero at a linear rate through 2030 (i.e. storage costs flatten out by 2030). Cost reduction factors are applied equally to capital costs in the capacity and duration categories.

[25] Available at: https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf
[26] Available at: https://www.nrel.gov/docs/fy19osti/71714.pdf

Table 42. Capital cost assumptions for candidate battery resources

Resource	Cost Component	Case	2027	2030	2035	2040	2045
Li-Ion Battery (Utility-Scale)	Capital Cost – Power ($/kW)	Low	$177	$147	$147	$107	$88
		Mid	$191	$162	$162	$122	$105
		High	$228	$196	$196	$153	$137
	Capital Cost – Energy ($/kWh)	Low	$221	$184	$184	$133	$110
		Mid	$265	$224	$224	$169	$145
		High	$392	$338	$338	$264	$235
	Fixed O&M (%)	All	1.5%	1.5%	1.5%	1.5%	1.5%
Li-Ion Battery (BTM)	Capital Cost – Power ($/kW)	Low	$180	$150	$150	$111	$96
		Mid	$245	$207	$207	$157	$139
		High	$300	$259	$259	$202	$180
	Capital Cost – Energy ($/kWh)	Low	$382	$318	$318	$234	$204
		Mid	$546	$462	$462	$350	$309
		High	$686	$590	$590	$461	$411
	Fixed O&M (%)	All	3.20%	3.20%	3.20%	3.20%	3.20%
Flow Battery	Capital Cost – Power ($/kW)	Low	$611	$545	$545	$452	$415
		Mid	$1,240	$1,119	$1,119	$944	$872
		High	$1,882	$1,717	$1,717	$1,473	$1,373
	Capital Cost – Energy ($/kWh)	Low	$169	$151	$151	$125	$115
		Mid	$222	$200	$200	$169	$156
		High	$276	$252	$252	$216	$202
	Fixed O&M (%)	All	0.80%	0.80%	0.80%	0.80%	0.80%

Battery capital costs are fed into a pro forma model to estimate levelized fixed costs, using the following assumptions: financing lifetime of 20 years (10 years for BTM batteries), ITC eligibility, and after-tax WACC of 6.77% (in 2030). The resulting all-in levelized fixed costs of the mid case are shown in Table 43.

Table 43. Candidate battery levelized fixed costs - Mid

Resource	Cost Component	2020	2022	2026	2030
Li-Ion Battery	Levelized Fixed Cost – Power ($/kW-yr)	$23	$18	$12	$10
	Levelized Fixed Cost – Energy ($/kWh-yr)	$46	$37	$26	$22
Li-Ion Battery (BTM)	Levelized Fixed Cost – Power ($/kW-yr)	$50	$40	$29	$26
	Levelized Fixed Cost – Energy ($/kWh-yr)	$138	$113	$83	$73
Flow Battery	Levelized Fixed Cost – Power ($/kW-yr)	$140	$117	$91	$84
	Levelized Fixed Cost – Energy ($/kWh-yr)	$25	$21	$15	$14

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

4.4 Demand Response

4.4.1 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 report for the CPUC: Final Report on Phase 2 Results: 2025 California Demand Response Potential Study.27 The resource potential supply curve is based on data outputs from LBNL's DRPATH model, with the scenario assumptions outlined below in Table 44. 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 (

Figure *4.4***Error! Reference source not found.**). To reflect the lead time that would be required to ramp up shed DR availability, the potential of each tranche of the Shed DR supply curve is phased in linearly between 2020 and 2025. An alternative option, included as an option for sensitivity

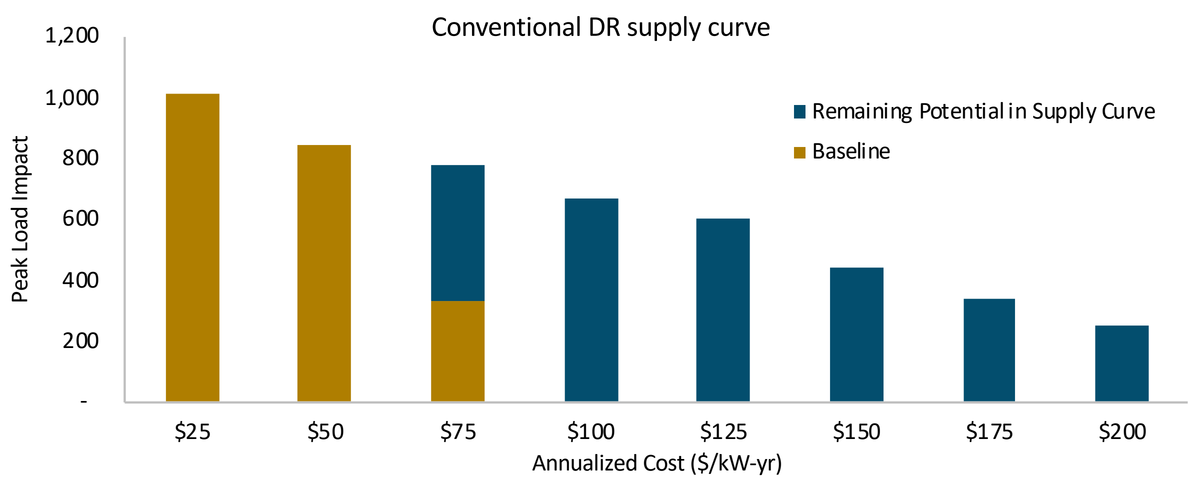
[27] Lawrence Berkeley National Laboratory, *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study* (2017). Available at: http://www.cpuc.ca.gov/General.aspx?id=10622

analysis, explores resource portfolio selection when all shed DR potential is available in all modeled years.

Table 44. Scenario assumptions for LBNL's DRPATH model used to generate shed DR supply curve data for IRP modeling

Category	Assumption
Base year	2020
DR Availability Scenario	Medium
Weather	1 in 2 weather year
Energy Efficiency Scenario	Mid AAEE
Rate Scenario	Rate Mix 1—TOU and CPP (as defined by LBNL report)
Cost Framework	Gross

Figure 4.4. Conventional Demand Response Supply Curve

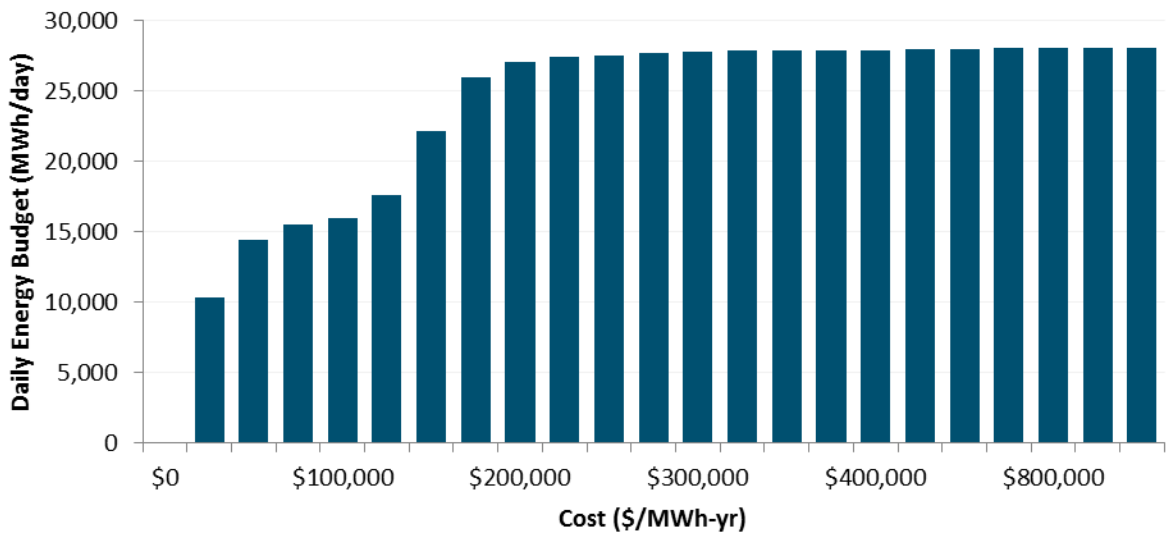


4.4.2 Shift Demand Response

"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. RESOLVE includes a constraint that sets a maximum quantity of energy that can be shifted in one hour. It is currently assumed that the full daily energy budget is available on every day of the year. 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 CPUC: *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study*.[28] 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 44).

Figure 4.5. Shift demand response: total annual costs vs potential daily energy budget



[28] Lawrence Berkeley National Laboratory, *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study* (2017). Available at: http://www.cpuc.ca.gov/General.aspx?id=10622

5. Pro Forma Financial Model

This section describes the purpose of and methodology behind the pro forma financial model. The pro forma model is a discounted cash flow model used to calculate the levelized costs of different candidate resources. The primary outputs from the model are the levelized fixed costs for each resource. Levelized fixed costs calculated by the pro forma include the overnight capital cost for each resource, financing costs (including investor returns on a project), fixed O&M costs, and any capital-based tax credits, such as the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which are used to offset capital costs.

The pro forma used for the CEC SB100 analysis assumes financing is provided by an Independent Power Producer (IPP), which reflects current development practices in which most new resources in California are third-party owned and contracted with LSEs rather than financed by LSEs themselves. Financing assumptions assumed in the pro forma model are based on NREL's 2019 Annual Technology Baseline.[29]

Levelized costs are calculated in the pro forma using real levelization to yield costs that are flat in real dollar terms. 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.

The pro forma also requires information on variable costs (such as fuel and variable O&M) and resource performance characteristics. 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.

[29] Financing assumptions include WACC, cost of debt and debt fraction. E3 adjusted NREL's cost of debt to reflect the current rate environment. based on the spread to the Industrial Baa bond rate, as used by EIA in the Annual Energy Outlook.

6. Operating Assumptions

6.1 Overview

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 California to meet the contingency and flexibility reserve needs of the BAA within California
- **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes three zones: one zone capturing California balancing authorities and two zones that represent regional aggregations of out-of-state balancing authorities.[30] The constituent balancing authorities included in each RESOLVE zone are shown in Table 45.

[30] 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.

Table 45. Constituent balancing authorities in each RESOLVE zone

RESOLVE Zone	Balancing Authorities
CA	California Independent System Operator (CAISO) Los Angeles Department of Water and Power (LADWP) Imperial Irrigation District (IID) Balancing Authority of Northern California (BANC) Turlock Irrigation District (TID) [aggregated as part of the BANC associated loads and resources]
NW	Avista Corporation (AVA) Bonneville Power Administration (BPA) Chelan County Public Utility District (CHPD) Douglas County Public Utility District (DOPD) Grant County Public Utility District (GCPD) Idaho Power Company (IPC) NorthWestern Energy (NWMT) Pacificorp East (PACE) Pacificorp West (PACW) Portland General Electric Company (PGE) Puget Sound Energy (PSE) Seattle City Light (SCL) Sierra Pacific Power (SPP) Tacoma Power (TPWR) WAPA – Upper Wyoming (WAUW)
SW	Arizona Public Service Company (APS) El Paso Electric Company (EPE) Nevada Power Company (NEVP) Public Service Company of New Mexico (PNM) Salt River Project (SRP) Tucson Electric Power Company (TEP) WAPA – Lower Colorado (WALC)
Excluded (not modeled)	Alberta Electric System Operator (AESO) British Columbia Hydro Authority (BCHA) Comision Federal de Electricidad (CFE) Public Service Company of Colorado (PSCO)

	WAPA – Colorado-Missouri (WACM)

- **Representative sampling of days:** 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. RESOLVE incorporates a smart day sampling algorithm to reduce the number of simulated days from 365 (a full year) to 37. Load, wind, and solar profiles for these 37 days, sampled from the historical meteorological record of the period 2007-2009, are selected and assigned weights so that taken in aggregate, they produce a reasonable representation of complete distributions of potential conditions; daily hydro conditions are sampled separately from low (2008), medium (2009), and high (2011) hydro years to provide a wide distribution of potential hydro conditions. An optimization algorithm selects the days and identifies the weight for each day such that distributions of load, net load, wind, and solar generation match long-run distributions. This allows RESOLVE to approximate annual operating costs and dynamics while maintaining reasonable model runtime.

Table 46. RESOLVE's 37 days and associated weights

Index	Weather Date	Hydro Condition	Day Weight	Index	Weather Date	Hydro Condition	Day Weight
1	1/1/07	High	14.250	20	5/7/08	High	5.808
2	1/2/07	Mid	5.908	21	5/19/08	Low	15.361
3	2/12/07	High	28.022	22	6/2/08	Low	17.733
4	3/6/07	High	14.341	23	8/3/08	Mid	20.807
5	3/20/07	Low	6.699	24	10/28/08	Low	1.167
6	4/2/07	High	0.495	25	11/5/08	Mid	12.447
7	4/8/07	Low	2.197	26	12/20/08	High	33.401
8	4/15/07	Low	1.133	27	1/6/09	Mid	0.881
9	5/5/07	Mid	5.384	28	1/21/09	Mid	7.922
10	5/29/07	High	3.902	29	3/26/09	High	8.913
11	6/2/07	High	9.228	30	4/4/09	Low	3.381
12	6/16/07	High	1.631	31	4/17/09	High	9.045
13	7/17/07	Mid	31.789	32	4/24/09	High	5.718
14	8/7/07	High	4.542	33	4/25/09	Low	4.810
15	9/2/07	High	13.817	34	4/25/09	High	0.903
16	9/26/07	Low	16.348	35	6/24/09	High	1.748
17	11/27/07	High	19.042	36	8/17/09	Low	5.811
18	1/28/08	Mid	0.664	37	10/6/09	High	28.928
19	4/4/08	High	0.822	**Total**			**365.000**

6.2 Load Profiles and Renewable Generation Shapes

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

6.2.1 Load Profiles

Load profiles are based on historical loads for the zones of interest as reported by the Western Electricity Coordinating Council (WECC) for 2007-2009. These profiles are assumed to reflect the baseline consumption profile because at that time there was virtually no behind-the-meter PV, electric vehicles, additional energy efficiency, or time-of-use rate impacts. For the loads in non-California zones, the profiles are used without modification. For the California loads, the final load profile is created by adding or subtracting load modifier shapes from the baseline consumption load profile on an hourly basis. Load modifiers with hourly shapes include: energy efficiency, electric vehicles, building electrification, other electrification, and time-of-use rate impacts. In addition, behind-the-meter PV is modeled with an hourly production profile.

6.2.1.1 Energy Efficiency Profiles

Energy efficiency is modeled as a load-modifier (not a candidate resource) in the CEC SB100 model. Load-modifier energy efficiency hourly profiles use data from the CEC's 2019 IEPR Demand Forecast.

6.2.1.2 Electric Vehicle Load Profiles

EV load profiles included in the CEC 2019 IEPR Demand Forecast are used as the default EV charging profiles in the CEC SB100 model.

RESOLVE has the capability to simulate flexible EV charging, which lets the EV charging shape be adjusted in RESOLVE's internal production simulation subject to constraints on charging flexibility. For vehicles that can charge flexibly, the optimal charging shape is constrained by the amount of vehicles that are plugged in, which defines how much charge capacity is available, and the instantaneous driving demand for that hour, which affects the state-of-charge of the fleet. The default assumption is to have no flexible EV charging simulated within RESOLVE. However, driver behavior response to TOU rates and other incentives, to the extent captured in the IEPR EV load profiles, is reflected in the analysis.

6.2.1.3 Building Electrification Load Profiles

Building space heating load shapes come from E3's RESHAPE model. As inputs, RESHAPE incorporates a characterization of California's residential and commercial buildings from EIA Residential Energy Consumption Survey (RECS) and Commercial Buildings Energy Consumption Survey (CBECS) data, county-level weather data from NOAA's North American Regional Reanalysis, and forecasts of heat pump adoption, building growth, and building shell efficiency from the PATHWAYS model. RESHAPE first generates hourly heating demands, then uses representative heat pump technologies to model hourly electric loads. Electric loads are generated at the county level, then aggregated into a diversified statewide load shape. The space heating load shapes are integrated with PATHWAYS water heating, cooking, and clothes drying shapes to determine an aggregate building electrification shape.

6.2.1.4 Other Electrification Load Profiles

The Other Electrification load shape is based on the PATHWAYS model industrial load shape.

6.2.1.5 Time-of-Use Rates Adjustment Profiles

Time-of-use (TOU) rate profile impacts are based on the CEC's 2018 IEPR. TOU load impacts are binned into month-hour averages and applied to the relevant periods of the 37 modeled days.

6.2.1.6 Hydrogen Load Flexibility Assumptions

Hydrogen electrolysis load – only modeled in the High Hydrogen mitigation scenario – does not have a fixed profile, and is instead modeled as a flexible load in RESOLVE. The PATHWAYS model provides annual electrolysis demand, which is used in conjunction with flexibility assumptions in RESOLVE to determine the timing of hydrogen load. Within each year simulated by RESOLVE, hydrogen electrolysis load is assumed to be constant on each day, and electrolyzer capacity is assumed to be built at four times the daily average demand. This is roughly the capacity necessary to meet daily hydrogen demand only during mid-day hours – hours in which solar energy is likely to be abundant. 25% of electrolysis load is assumed to be baseload and inflexible. The remaining 75% of electrolysis load can be dispatched within each RESOLVE day, and load cannot be shared between days. No planning reserve margin impact of hydrogen production is included – conceptually hydrogen electrolysis acts like a load that provides shed demand response by relying on hydrogen storage capacity.

6.2.2 Solar Profiles

Solar profiles for RESOLVE are created using NREL's PVWATTSv5 calculator.[31] The software creates PV production profiles based on weather data from the National Solar Radiation Database (NSRDB),[32] and is used to produce both utility-scale and behind-the-meter solar profiles. 2007-2009 NSRDB weather data is used.

For each of the candidate solar resources modeled in RESOLVE, PV production profiles for representative latitude-longitude coordinates are simulated with a north-south single-axis tracking configuration and an inverter loading ratio of 1.3. Aggregate profiles are obtained by averaging production profiles across the representative locations. Baseline utility-scale solar

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

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

profiles are simulated using location, and tracking/tilt information for existing solar installations from 2017 EIA Form 860 Schedule 3. Installed capacity for individual baseline solar installations is used to create a single weighted-average baseline solar profile. A behind-the-meter PV weighted-average profile is created using locational and installed capacity information from the California Solar Initiative database. An inverter loading ratio of 1.1 is assumed for behind-the-meter PV.

Before the solar profiles can be used in RESOLVE, they are scaled such that the weighted capacity factor of the 37 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 following data:

- Candidate resources - average simulated capacity factor from historical 2007-2009 weather conditions
- Baseline resources within CAISO – weighted average capacity factor from the CPUC RPS contracts database
- Baseline resources outside of CAISO – weighted average capacity factor from the 2026 WECC Common Case
- Behind-the-meter PV – CEC 2018 IEPR BTM PV capacity factor(20%)

Solar capacity factors are shown in Table 47. [33]

[33] 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 47. Solar Capacity Factors in RESOLVE

Category	Resource	Capacity Factor
Baseline Resources	BANC_Solar_for_Other	29%
	CAISO_Solar_for_CAISO	28%
	CAISO_Solar_for_Other	28%
	Customer_PV	20%
	IID_Solar_for_CAISO	34%
	IID_Solar_for_Other	31%
	LDWP_Solar_for_Other	30%
	NW_Solar_for_Other	24%
	SW_Solar_for_CAISO	32%
	SW_Solar_for_Other	27%
Candidate Resources	Arizona_Solar	31%
	Carrizo_Solar	31%
	Central_Valley_North_Los_Banos_Solar	29%
	Distributed_Solar	21%
	Greater_Imperial_Ex_Solar	31%
	Greater_Imperial_Solar	31%
	Greater_Kramer_Solar	32%
	Inyokern_North_Kramer_Solar	32%
	Kern_Greater_Carrizo_Solar	31%
	Kramer_Inyokern_Ex_Solar	32%
	New_Mexico_Solar	30%
	North_Victor_Solar	32%
	Northern_California_Ex_Solar	28%
	Pisgah_Solar	32%
	Riverside_Palm_Springs_Solar	31%
	Sacramento_River_Solar	28%
	SCADSNV_Solar	31%
	Solano_Solar	29%
	Solano_subzone_Solar	29%
	Southern_California_Desert_Ex_Solar	31%
	Southern_Nevada_Solar	31%
	Tehachapi_Ex_Solar	32%
	Tehachapi_Solar	32%
	Utah_Solar	29%
	Westlands_Ex_Solar	31%

6.2.3 Wind Profiles

Hourly shapes for wind resources are obtained from NREL's Wind Integration National Dataset ("WIND") Toolkit.[34] For each of the wind resources modeled in RESOLVE, wind production profiles are collected for the years 2007-2009 from a set of representative locations. The profiles are then scaled using a filter such that the weighted capacity factor of the 37 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 resource profile capacity factors are scaled using the following data:

- Candidate onshore resources – CPUC RPS Calculator v.6.3 supply curve[35]
- Candidate offshore wind resources – average simulated capacity factor from historical 2007-2009 weather conditions[36]
- Baseline resources within CAISO – weighted average capacity factor from the CPUC RPS contracts database
- Baseline resources outside of CAISO – weighted average capacity factor from the 2026 WECC Common Case

[34] See: https://www.nrel.gov/grid/wind-toolkit.htm

[35] Black & Veatch, *RPS Calculator V6.3 Data Updates*. Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/RPSCalc_CostPotentialUpdate_2016.pdf. Note that although the data was developed with the intention of incorporating it into a new version of the RPS Calculator, no version 6.3 was been developed. This is because the IRP system plan development process replaced the function previously served by the RPS Calculator.

[36] Assumptions are consistent with the "California Offshore Wind: Workforce Impacts and Grid Integration" report: http://laborcenter.berkeley.edu/offshore-wind-workforce-grid/. Profiles are obtained from NREL's Toolkit and assume a next-generation 12-MW turbine with a hub height of 150 meters (nearly 500 feet) and a power curve similar to the GE Haliade-X turbine. Due to a paucity of generation data for sites within the boundaries of the selected resource zones, this study uses single representative sites from NREL's Wind Toolkit database for each of the five resource zones. As a result, the simulated power output for each zone may not reflect the full range of local wind conditions in the areas surrounding each site.

Table 48. Wind Capacity Factor in RESOLVE

Category	Resource	Capacity Factor
Baseline Resources	BANC_Wind_for_Other	30%
	CAISO_Wind_for_CAISO	28%
	CAISO_Wind_for_Other	28%
	IID_Wind_for_Other	34%
	LDWP_Wind_for_CAISO	30%
	LDWP_Wind_for_Other	30%
	NW_Wind_for_CAISO	27%
	NW_Wind_for_Other	29%
	SW_Wind_for_CAISO	48%
	SW_Wind_for_Other	44%
Candidate Resources	Arizona_Wind	30%
	Baja_California_Wind	36%
	Carrizo_Wind	31%
	Central_Valley_North_Los_Banos_Wind	31%
	Greater_Imperial_Ex_Wind	34%
	Greater_Imperial_Wind	34%
	Greater_Kramer_Wind	31%
	Humboldt_Wind	29%
	Idaho_Wind	32%
	Inyokern_North_Kramer_Wind	31%
	Kern_Greater_Carrizo_Wind	31%
	Kramer_Inyokern_Ex_Wind	31%
	New_Mexico_Wind	44%
	North_Victor_Wind	31%
	Northern_California_Ex_Wind	29%
	NW_Ext_Tx_Wind	30%
	Pacific_Northwest_Wind	32%
	Pisgah_Wind	31%
	Riverside_Palm_Springs_Wind	34%
	Sacramento_River_Wind	29%
	SCADSNV_Wind	30%
	Solano_subzone_Wind	30%
	Solano_Wind	30%
	Southern_California_Desert_Ex_Wind	30%

	Southern_Nevada_Wind	28%
	SW_Ext_Tx_Wind	36%
	Tehachapi_Ex_Wind	34%
	Tehachapi_Wind	34%
	Utah_Wind	31%
	Westlands_Ex_Wind	31%
	Wyoming_Wind	44%
Candidate Offshore Wind Resources	Cape_Mendocino_Offshore_Wind	53%
	Del_Norte_Offshore_Wind	52%
	Diablo_Canyon_Offshore_Wind	46%
	Humboldt_Bay_Offshore_Wind	52%
	Morro_Bay_Offshore_Wind	55%

6.3 Operating Characteristics

6.3.1 Natural Gas, Coal, and Nuclear

The thermal fleet in RESOLVE is represented by a limited number of resources within each zone, each representing a class of thermal generating units (CCGT, Steam Turbine, Peaker, etc.). Within each zone, each resource uses weighted-average operating parameters that are 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 resource class are compiled from the January 2019 vintage version of the CAISO MasterFile and the WECC 2028 Anchor Data Set Phase 2 V1.2. Variable operations and Maintenance Costs (VO&M) are sourced from a 2018 Nexant report submitted to CAISO.[37] Several plant types are modeled using operational information from other sources:

- The **CA_Aero_CT** and **CA_Advanced_CCGT** operating characteristics are based on manufacturer specifications of the latest available models of these class.
- The **CAISO_CHP** plant type is modeled as a must-run resource with an assumed net heat rate of 7,600 Btu/kWh, which is based on CARB's Scoping Plan assumptions for cogeneration. A monthly generation schedule for CAISO_CHP is developed using historical settlement data.

[37] See http://www.caiso.com/Documents/VariableOperationsandMaintenanceCostReport-Dec212018.pdf

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. 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.

6.3.2 Hydro

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

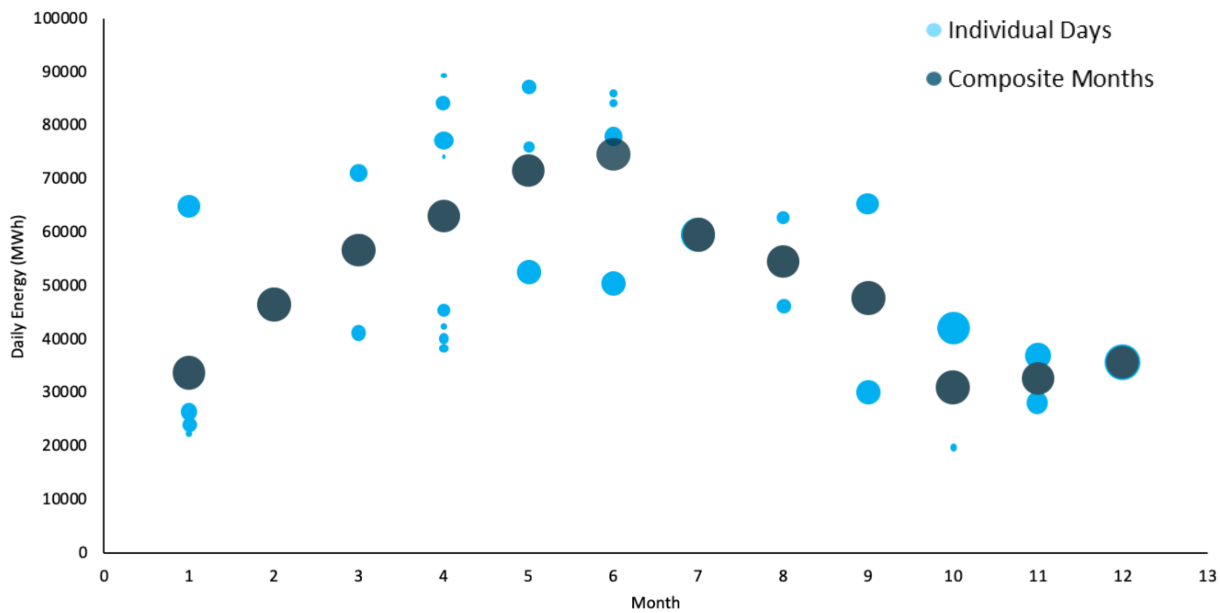
Daily energy budget: the total amount of energy, in MWh, to be dispatched throughout the day.

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.

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, RESOLVE representative day #3 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 6.1. CAISO hydro energy budgets



In the chart above, each of the 37 days is shown as a light blue point according to its calendar month. The size of the bubble in the diagram above represents the weight assigned to that day in RESOLVE. The dark blue points represent the average hydro budget for all days in that month.

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, the daily energy budgets for other regions is 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.

6.3.3 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 2019-2020 IRP can perform energy arbitrage but do not contribute to operational reserve requirements.

For all storage devices, RESOLVE does not 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. RESOLVE does not include ramp rates for storage devices, implicitly assuming that they can ramp quickly over their full operable range. The round-trip efficiency 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.

Table 49. 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	81%	12

6.4 Operational Reserve Requirements

As described in Table 50 below, RESOLVE models 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 of the 37 representative days.

Reserves can be provided by available headroom or footroom from various resources, subject to operating limits (Table 50). 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.

Given that the California generation fleet does not include coal- or oil-fired generators, Table 50 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 50. Reserve types modeled in RESOLVE

Product	Description	RESOLVE 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.	The requirement varies hourly and is formulated using a root mean square of the following values for each hour: 1% of the hourly California 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.	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.	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.	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.
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	939 MW of headroom is held in all hours on gas-fired, conventional hydroelectric, pumped storage, and battery resources. At least half of the headroom (470 MW) must be held on gas-fired and battery resources.	Reflecting governor response limitations, gas-fired generators can contribute available headroom up to 8% of their committed capacity. Wholesale battery storage, pumped storage, and

Product	Description	RESOLVE Requirement	Operating Limits
	response and is typically only deployed in contingency events.		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 California load.	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

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.

2017-2018 CAISO hour-ahead forecasts and 5-minute actual values of load, wind, and solar are used to develop the load following and regulation requirements. 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 are calculated for the years 2020 and 2030 using 1) load profiles scaled to future annual projected load and 2) wind and solar profiles scaled to baseline installed capacity (2020) or baseline and selected capacity built from a preliminary CPUC 2019/2020 IRP 46 MMT case (2030). Requirements for years between 2020 and 2030 are linearly interpolated on an hourly basis using the 2020 and 2030 values. The same linear relation is used to extrapolate for reserve requirements beyond 2030.

Table 51 below summarizes the minimum, maximum and average load following and regulation requirements in the upwards and downwards directions for 2020 and 2030. The requirements typically exhibit maximums during daylight hours and minimums at night, which reflects the forecast uncertainty imposed by large penetrations of solar energy.

Table 51. Summary of Load Following and Regulation Requirements Modeled in RESOLVE

Reserve Product	2020			2030		
	Maximum (MW)	Minimum (MW)	Average (MW)	Maximum (MW)	Minimum (MW)	Average (MW)
Load Following Up	3,302	467	2,089	7,375	1,872	3,831
Load Following Down	4,582	122	1,897	10,546	146	3,510
Regulation Up	899	150	381	2,075	174	734
Regulation Down	1,697	132	401	4,033	149	781

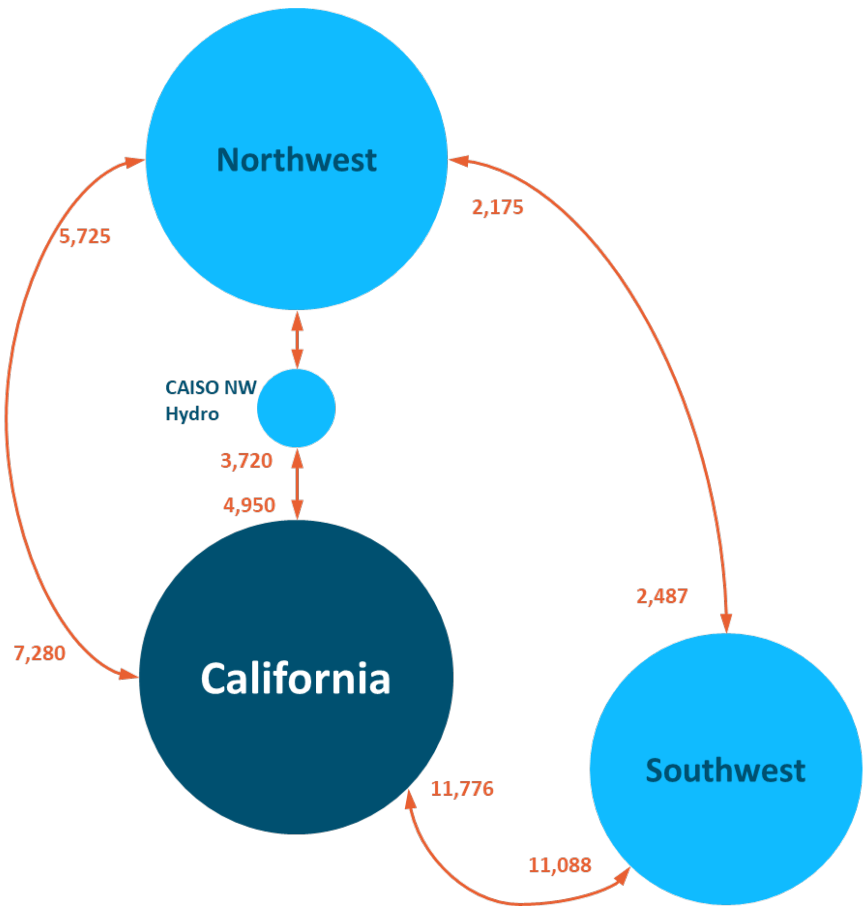
6.5 Transmission Topology

Transmission flow limits between RESOLVE BAAs are the sum of flow limits between individual BAAs in the CPUC's SERVM model.[38] SERVM flow limits were in-turn derived from the CAISO's 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 2028 ADS 2.0 dataset and path limits from WECC Path Rating 2018 catalog. The CEC's PLEXOS model was used as a

[38] 2019 Unified RA and IRP Modeling Datasets available at: https://www.cpuc.ca.gov/General.aspx?id=6442461894

supplemental data source for paths that did not have enough geographic resolution in CAISO's dataset.

Figure 6.2. 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 California. 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 simultaneous import limits into California, taking into account resources that are external to California but are modeled in RESOLVE as within California (the California LSE share of Hoover, Intermountain Power Plant, and Palo Verde).

Table 52. Assumed California net export and net import limits (MW)

Constraint	2027	2030	2035	2040	2045
Net Export Limit	4,000	5,000	5,000	5000	5,000
Net Import Limit	10,208	10,208	10,208	10,208	10,208

6.5.1 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 CPUC 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 average export hurdle of the constituent BAAs, plus an additional hurdle for a zone adjacent to CAISO: APS for the SW and BPA for the NW.

Table 53. Hurdle Rates in RESOLVE ($/MWh)

Export Zone	Hurdle Rate ($/MWh)
From BANC	$2.42
From CAISO	$10.39
From IID	$3.18
From LADWP	$5.59
From NW	$4.91
From SW	$7.35

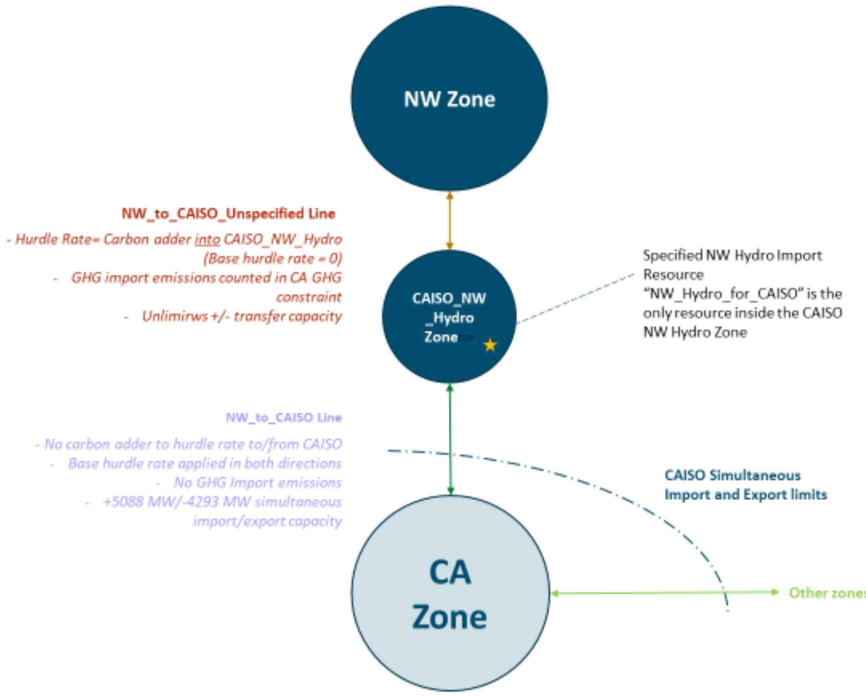
In addition to cost-based hurdle rates, an additional cost from CARB's cap and trade program is added to unspecified imports into California; this cost is calculated based on the relevant year's carbon allowance cost and a deemed rate of 0.428 metric tons/MWh.[39]

6.5.2 Transmission Topology for Specified Imports of NW Hydro

As shown in Figure 6.3, the 2019 IRP RESOLVE model has been updated to represent 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 in between the NW and California and does not have any load. All unspecified imports from the NW to California, and exports from California to the NW, must pass through the CAISO_NW_Hydro zone. Emissions from unspecified imports from the NW are counted towards California'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 the NW_to_CAISO transmission line between the CAISO zone and the CAISO_NW_Hydro zone. The NW_to_CAISO line is subject to the simultaneous import and export limits between California and the Northwest.

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

Figure 6.3. Transmission Topology of NW Hydro Imports in RESOLVE



6.6 Fuel Costs

Three options for fuel costs are included in RESOLVE, each of which is based on a WECC burner tip price estimate from the CEC's NAMGas model run posted in April 2019.[40] Prices for each RESOLVE region are aggregated from NAMGas burner tip information using the average of the region of interest. Hydrogen fuel cost estimates include hydrogen production cost,[41] storage cost,[42] and pipeline cost.[43]

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[40] Available here: https://ww2.energy.ca.gov/assessments/ng_burner_tip.html.

[41] Assuming off-grid California wind or solar to power the electrolyzer, with electrolyzer costs and trajectories developed by the University of California at Irvine (UCI) for the E3 study "The Challenge of Retail Gas in California's Low-Carbon Future" for the California Energy Commission:
Aas, Dan, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, and Snuller Price. 2020. *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. Appendix C.* California Energy Commission. Publication Number: CEC-500-2019-055-AP-G. https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-AP-G.pdf

[42] Based on the H2A Analysis by the US Department of Energy (DOE): https://www.hydrogen.energy.gov/h2a_analysis.html.

[43] Navigant. 2019. *Gas for Climate. The Optimal Role for Gas in a Net-Zero Emissions Energy System.* https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf

Table 54. Fuel Cost Forecast – Low ($/MMBtu, 2016$)

Fuel Type	2027	2030	2035	2040	2045
CA_Natural_Gas	$3.54	$3.53	$3.35	$3.19	$3.01
NW_Natural_Gas	$3.16	$3.17	$3.19	$3.21	$3.23
SW_Natural_Gas	$1.87	$1.87	$1.79	$1.72	$1.64
CA_Coal	$2.00	$2.00	$2.00	$2.00	$2.00
Coal	$2.00	$2.00	$2.00	$2.00	$2.00
Uranium	$0.70	$0.70	$0.70	$0.70	$0.70
Hydrogen	$28.41	$26.15	$23.07	$21.09	$19.44

Table 55. Fuel Cost Forecast – Mid ($/MMBtu, 2016$).

Fuel Type	2027	2030	2035	2040	2045
CA_Natural_Gas	$4.34	$4.36	$4.43	$4.50	$4.57
NW_Natural_Gas	$3.38	$3.40	$3.41	$3.42	$3.44
SW_Natural_Gas	$2.62	$2.64	$2.78	$2.92	$3.06
CA_Coal	$2.00	$2.00	$2.00	$2.00	$2.00
Coal	$2.00	$2.00	$2.00	$2.00	$2.00
Uranium	$0.70	$0.70	$0.70	$0.70	$0.70
Hydrogen	$47.61	$45.28	$41.67	$39.40	$37.68

Table 56. Fuel Cost Forecast – High ($/MMBtu, 2016$).

Fuel Type	2027	2030	2035	2040	2045
CA_Natural_Gas	$5.12	$5.10	$5.07	$5.05	$5.03
NW_Natural_Gas	$3.59	$3.60	$3.62	$3.63	$3.64
SW_Natural_Gas	$3.32	$3.32	$3.34	$3.34	$3.34
CA_Coal	$2.00	$2.00	$2.00	$2.00	$2.00
Coal	$2.00	$2.00	$2.00	$2.00	$2.00
Uranium	$0.70	$0.70	$0.70	$0.70	$0.70
Hydrogen	$47.61	$45.28	$41.67	$39.40	$37.68

The CEC SB100 analysis assumptions include three options for carbon costs. Each option is based on revised 2019 IEPR Preliminary Nominal Carbon Price Projections.[44] The carbon projections increase 5% year-over-year in real terms. Nominal prices are converted to real $2016 for use in RESOLVE. RESOLVE only applies these carbon prices to resources in California, as well as unspecified imports into California. The CEC SB100 model inputs also include the option to run RESOLVE without a carbon price via the "Zero" trajectory. The "Low" trajectory is used by default.

Table 57. Carbon Cost Forecast Options ($/tCO2, 2016$)

Fuel Type	2027	2030	2035	2040	2045
Low	$21.66	$25.25	$32.55	$41.96	$54.09
Mid	$40.82	$58.21	$105.20	$190.11	$343.57
High	$49.26	$74.80	$150.08	$301.09	$604.08
Zero	-	-	-	-	-

[44] Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=227328&DocumentContentId=58424

7. Resource Adequacy Requirements

7.1 System Resource Adequacy

To ensure that the optimized generation fleet is sufficient to meet resource adequacy needs throughout the year, RESOLVE includes a planning reserve margin constraint for the California zone that requires the total available generation plus available imports in each year to meet or exceed a 15% margin above the annual 1-in-2 peak demand. The California 1-in-2 managed peak demand in each year is calculated by adding or subtracting demand-side modifiers from the baseline consumption forecast (Section 2.2). As discussed below, the contribution of each resource to the 15% margin requirement depends on its performance characteristics and availability to produce power during the most constrained periods of the year.

7.1.1 Gas, Coal, and Nuclear Resources

The contribution of gas, coal, and nuclear generators to resource adequacy is based on CAISO's Net Qualifying Capacity (NQC) list. The weighted-average NQC value for each class of generator (CCGT, CT, ST, Nuclear, etc.), expressed as a percentage of nameplate capacity, is calculated from the NQC list for September. In RESOLVE, this percentage is multiplied by the nameplate capacity of each class of generator to arrive at the contribution of existing and new resources towards the planning reserve margin. For most gas, coal, and nuclear generators, these percentages are relatively close to 100%. Note that the only coal resource in California is the Intermountain Power Plant – a dedicated import from Utah.

Table 58. Assumed Net Qualifying Capacity (NQC) for thermal generators (% of maximum capability)

Resource Class	NQC (% of max)
CHP	63%
Nuclear	99%
CCGT1	94%
CCGT2	100%
Coal	98%
Peaker1	92%
Peaker2	96%
Advanced_CCGT	95%
Aero_CT	95%
Reciprocating_Engine	100%
Gas Steam (ST)	100%

7.1.2 Hydro

The NQC of existing hydroelectric resources is based on CAISO's NQC list for September 2018. The same NQC assumptions are applied to non-CAISO hydro.

7.1.3 Demand Response

The contribution of demand response resources to the resource adequacy requirement, including new shed DR resources selected by RESOLVE, is assumed to be equal to the 1-in-2 ex ante peak load impact.

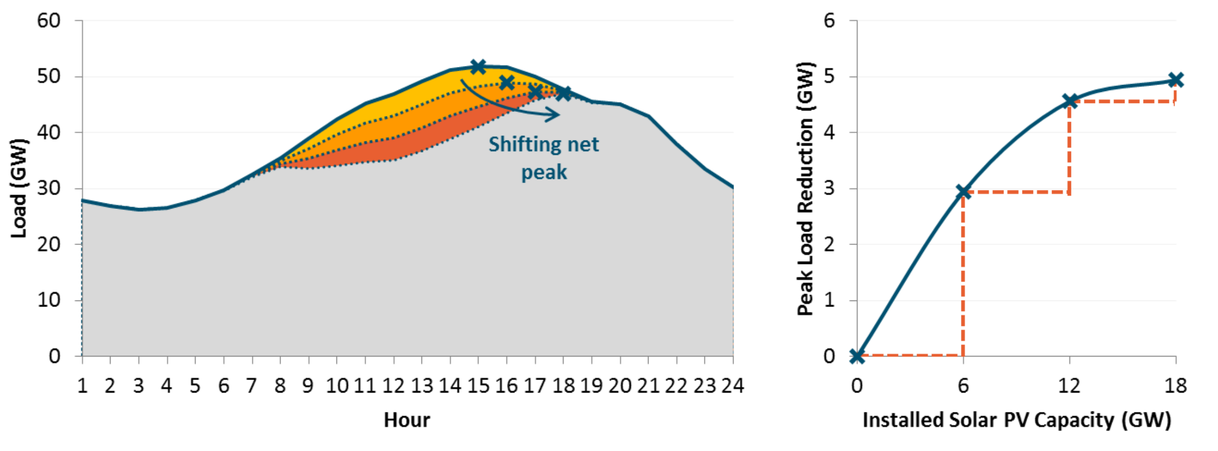
7.1.4 Renewables

Renewable resources with full capacity deliverability status (FCDS) (Section 4.2.7) are assumed to contribute to system resource adequacy requirements. Within RESOLVE, these resources fall into two categories: (1) firm, which includes biomass, geothermal, and small hydro; and (2) variable resources, which includes both solar and wind resources. The treatment of each category reflects the differences in their intermittency.

For candidate firm renewables, the contribution of each resource to resource adequacy is assumed to be equivalent to its average annual capacity factor (i.e., a geothermal resource with an 80% capacity factor is also assumed to have 80% net qualifying capacity). This assumption reflects the characteristic of firm resources that they produce energy throughout the year with a flat profile, and thereby their contribution to peak needs is not materially different from their average levels of production throughout the year. The capacity contribution of a candidate firm renewable resources is only counted towards the planning reserve margin constraint if RESOLVE allocates FCDS transmission capacity to the firm resource (Section 4.2.7). The NQC of baseline firm renewable resources is based on CAISO's NQC list for September.

To measure the contribution of variable renewable resources to system resource adequacy needs, RESOLVE uses the concept of "Effective Load Carrying Capability" (ELCC), defined as the incremental load that can be met when that resource is added to a system while preserving the same level of reliability. The contribution of wind and solar resources to resource adequacy needs depends not only on the coincidence of the resource with peak loads, but also on the characteristics of the other variable resources on the system. This relationship is illustrated by the phenomenon of the declining marginal capacity value of solar resources as the "net" peak demand shifts away from periods of peak solar production, as shown in Figure 7.1. Correctly accounting for the capacity contribution of variable renewable resources requires a methodology that accounts for the ELCC of the collective portfolio of intermittent resources on the system.

Figure 7.1. Illustrative example of the declining marginal ELCC of solar PV with increasing penetration[45]



To approximate the cumulative ELCC of California's wind and solar generators, RESOLVE incorporates a three-dimensional ELCC surface much like the one derived for Version 6 of the CPUC's RPS Calculator.[46] The surface expresses the total ELCC of a portfolio of wind and solar resources as a function of the penetration of each of those two resources; each point on the surface is the result of a single model run of E3's Renewable Energy Capacity Planning (RECAP) model. To incorporate the results into RESOLVE, the surface is translated into a multivariable linear piecewise function, in which each facet of the surface is expressed as a linear function of two variables: (1) solar penetration, and (2) wind penetration. The surface is normalized by annual load, such that the ELCC of a portfolio of resources will adjust with increases or decreases in load.

Each facet on the surface is a multivariate linear equation of the form fi(S,W) = aiS + biW + ci, where fi(S,W) is the total ELCC provided by wind & solar (expressed as a percentage of 1-in-2 peak demand) and S and W represent the penetrations of solar and wind, respectively (measured as a percentage of annual load). Because of the declining marginal ELCC of solar and wind (and the corresponding convexity of this surface), the cumulative ELCC F(S,W) for any penetration of wind and solar can be evaluated as the minimum of all twenty-four linear equations: F(S,W) = min[fi(S,W)].

BTM PV is modeled as a supply-side resource within the system resource adequacy constraint, and is therefore not represented as a demand-side modifier. Within the RESOLVE optimization,

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[45] For additional information see the RPSCalcWkshp_0203ResourceValuation.pptx and is located in the 02_RPS Calculator 6.0 Workshop_Feb2015 folder. Materials are available for download at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9366

[46] *Ibid*

the capacity value of BTM PV is calculated using the ELCC value of solar as described above. Additional adjustments are made to the planning reserve margin target to move BTM PV to the supply side (Section 2.2.4).

7.1.5 Energy Storage

For energy storage, a use-limited resource, the contribution to the planning reserve margin is a function of both the capacity and the duration of the storage device. To align with resource adequacy accounting protocols, RESOLVE assumes a resource with four hours of duration counts its full capacity towards the planning reserve margin, up to a capacity threshold (see the ELCC curve below). For resources with a duration of less than four hours, the capacity contribution is derated in proportion to the duration relative to a four-hour storage device (e.g. a 2-hour energy storage resource receives half the capacity credit of a 4-hour resource). This logic is applied to all baseline and candidate storage resources.

Battery storage does not provide equivalent capacity to dispatchable thermal resources at higher battery storage penetrations because storage flattens the net peak, requiring longer duration and/or higher stored energy volumes. Also, increasing penetrations face the challenge of having enough energy to charge to support peak demand. Consequently, RESOLVE includes a declining storage ELCC curve for utility-scale Li-Ion and Flow batteries that reduces the capacity value of battery storage at higher battery storage penetrations.

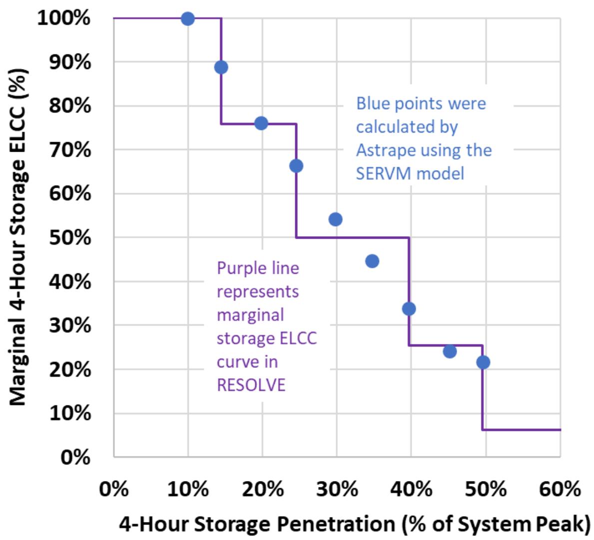
Astrapé Consulting used the SERVM model and CPUC's SERVM model database populated with the November 2019-vintage proposed 46 MMT Reference System Plan Portfolio[47] to calculate the capacity contribution of storage across a wide range of storage capacities . The portfolio used to develop the ELCC curve includes significant BTM and utility-scale solar capacity, which modifies the net load shape and by extension the capacity value of battery storage.. The ELCC curves may therefore overstate battery capacity value in a power system with lower levels of solar deployment, and care should be taken when using the curves outside of the context of the CPUC IRP.

Astrapé produced battery ELCC curves for 2022 and 2030 resource portfolios; the 2022 ELCC curve is used in RESOLVE for all years (Figure 7.2) because it is moderately more conservative than the 2030 curve. In an effort to balance model complexity and data fidelity, the number of steps in the 2022 curve produced by Astrapé was reduced in RESOLVE (see Figure 7.2). Astrapé's most recent simulations explored up to 50% of battery capacity relative to peak

[47]https://www.cpuc.ca.gov/General.aspx?id=6442463190

demand; results of a previous Astrape study[48] at even higher penetration levels were included at above 50% of peak.

Figure 7.2. Battery Storage ELCC Curve



The marginal battery capacity value as calculated in the RESOLVE optimization, expressed as a percentage of the battery power capacity, is equal to: Marginal ELCC [%, from Figure 7.2] * Min(1, Duration [hours]/4 hours).

7.1.6 Imports

Reflecting historical levels of RA import capacity, 5 GW is used as the default assumption for available RA import capacity (Table 59). Other options for RA import capacity include the Maximum Import Capability into CAISO, and a "Low" option that roughly approximates the capacity of dedicated import resources modeled in RESOLVE in 2020.

Table 59. Options for assumed import capability for resource adequacy.

RA Import Option	Capacity (MW)
Maximum Import Capability (High)	11,665
Default	5,000
Low	2,000

[48] https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2019-20%20IRP%20Astrape%20Battery%20ELCC%20Analysis.pdf

The RA import limit values above include the RA contribution of California LSE's contracted share of Palo Verde and Hoover resources. RESOLVE includes the capacity of these resources as a portion of the CAISO_Nuclear & LADWP_Nuclear and CAISO_Hydro & LADWP_Hydro resources respectively. Because their RA contribution counts towards California RA requirements at the resource level, the RA contribution of these resources (2,230 MW in 2020) is deducted from the import capability to determine the contribution of unspecified imports to the Planning Reserve Margin. For example, a 5 GW RA import limit is modeled in RESOLVE as (5,000 - 2,230) MW = 2,770 MW of unspecified RA imports, plus RA capacity from the Palo Verde and Hoover portions of the CAISO_Nuclear, LADWP_Nuclear, CAISO_Hydro, and LADWP_Hydro resources.

7.2 Local Resource Adequacy Constraint

RESOLVE includes a constraint that requires that sufficient generation capacity must be maintained or added to meet the local needs in Local Capacity Resource (LCR) areas. To characterize local capacity needs, RESOLVE relies on the CAISO's Transmission Planning Process (TPP). The 2018-19 TPP[49] does not identify any local areas as overall deficient, so RESOLVE does not include any incremental local capacity need.

7.3 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. While no incremental need for new capacity in local areas is modeled in the 2019-2020 cycle, the CAISO Local Capacity Technical Study (LCT Study)[50] demonstrates that electrical areas and sub-areas have limited transmission import capability. The LCT study determines the minimum generation capacity (MW) needed to fill local needs in case one or more transmission or generation elements is not available. CPUC Staff analysis uses the LCT Study to determine the minimum generation capacity that comes from thermal generation, referred to as Market Gas in the LCT Study. Market Gas values are used from the Category C Performance Criteria by Sub-Area, meaning the situation that would result from the loss of one element, time for adjustment, then loss of another element. The Minimum Thermal (Market Gas) requirement is calculated as the total MW Deficiency, less the generation other than Market Gas available in the Sub-Area. The minimum thermal requirement is allocated to

[49] CAISO 2018-'19 Transmission Plan, Appendix D: Local Capacity Technical Analysis, available at: http://www.caiso.com/Documents/Final2019LocalCapacityTechnicalReport.pdf
[50] http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx

individual units using the CAISO effectiveness factors list in Attachment B of the LCT, and the individual units are aggregated to RESOLVE generator classes. The RESOLVE optimization enforces the minimum retention values (Table 60) for each class of generator in each year.

Table 60. Minimum gas retention

RESOLVE Resource	2030 Planned Capacity (MW)	LCR capacity - retained indefinitely (MW)	Retention decided by RESOLVE (MW)
CAISO_CCGT1	13,333	8,412	4,921
CAISO_CCGT2	2,928	1,885	1,043
Peaker1	4,914	3,163	1,751
Peaker2	3,683	1,309	2,374
CAISO_Reciprocating_Engine	255	184	71

8. Renewable Portfolio Standard and SB100 Policy

8.1 Greenhouse Gas Constraint

While RESOLVE includes optionality to enforce a greenhouse gas (GHG) constraint on emissions, no constraint was used in the CEC SB100 RESOLVE modeling.

8.2 Greenhouse Gas Accounting

RESOLVE tracks greenhouse gas emissions attributed to entities 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 Generators

The annual emissions of generators 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 California

RESOLVE attributes emissions to generation that is imported to California 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[51]—a rate slightly higher than the emissions rate of a combined cycle gas turbine.

Specified imports to California are modeled as if the generator is located within California, therefore any emissions associated with specified imports are included with emissions associated with California generators. The majority of specified imports 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 the IRP, and therefore emissions from BTM CHP are not directly captured in RESOLVE's generation dispatch.[52] To retain consistency with CARB's Scoping Plan accounting conventions and the 2019-2020 IRP

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[51] Rules for CARB's Mandatory Greenhouse Gas Reporting Regulation are available here: https://ww2.arb.ca.gov/mrr-regulation

[52] 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.

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 the 2018 IEPR load forecast, totaling 5.5 MMT/yr in each year from 2020-2030.

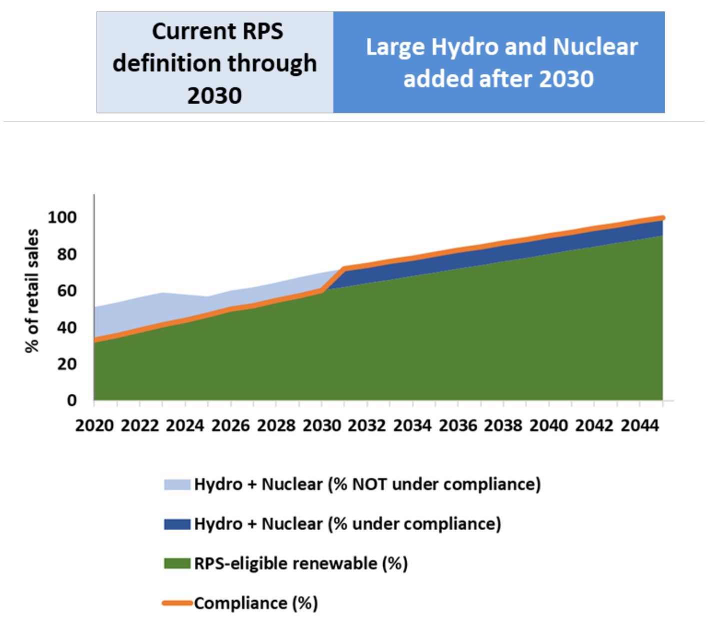
8.3 RPS/SB100 Constraint

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.

8.3.1 RPS requirement

RESOLVE includes a constraint that enforces RPS compliance in all modeled years. 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 result in selection of candidate renewable resources. However, only one of these constraints will typically be binding- either the RPS requirements will result in a lower emitting portfolio than the GHG limit, or the GHG constraint will result in higher renewable build than the RPS requirement. Reflecting SB100, renewables, nuclear and hydro are assumed to be RPS/SB100 eligible resources after 2030 (Figure 8.1). The retail sales compliance trajectory after 2030 is a modeling assumption and does not reflect policy direction.

Figure 8.1. RPS/SB100 compliance



8.3.2 RPS Banking

As a compliance option for 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 if the RPS constraint is driving renewable investment. For the CEC SB100 modelling, RESOLVE models a specified schedule of bank redemption (GWh in each year). This approach was used for the 2019-2020 IRP cycle and the 2017-2018 IRP cycle. IOU's 2018 RPS Plans are compiled to determine the starting bank in 2018. A schedule of REC bank accrual and redemption is then calculated by comparing CAISO-wide RPS requirements to baseline physical renewable production potential.

8.3.3 Storage Losses

The CEC SB100 RESOLVE model was updated to modify the accounting of storage losses within the RPS framework. In prior versions of RESOLVE, storage losses were treated like curtailment, where energy lost due to storage device roundtrip efficiency would not count toward annual RPS even if the energy had been generated by an RPS-eligible resource.

At the time, this was implemented to prevent a perverse incentive that the model had to "burn" excess renewable generation as storage losses by cycling rapidly (thus generating more RECs than the system otherwise could balance) but is inconsistent with the language of the policy. For example, in situations with significant renewable overgeneration, such as in 100% variable generation scenarios, storage resources would be incentivized in the model to charge and discharge simultaneously within a given hour. This behavior is possible in certain types of storage resources (notably flow batteries) but uncommon in other types (such as lithium-ion).

For the scenarios where storage losses were counted toward RPS, the RESOLVE model was updated to limit the ability for the storage resources to cycle on an hourly and daily basis. On an hourly basis, storage resources were limited to choosing to charge or discharge for fractions of the hour such that the resources were not simultaneously charging and discharging in any given hour. On a daily basis, storage resources were limited to cycling no more than 3 times/day, which was based on the maximum possible cycling of a 4-hour battery within a given 24-hour period.

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