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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