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Attachment A:

Proposed Inputs & Assumptions:

2019-2020 Integrated Resource Planning

November 2018

Table of Contents

Table of Contents

1. Introduction

This document describes the key data elements and proposed sources of inputs and assumptions for the California Public Utilities Commission's (CPUC's) 2019-2020 Integrated Resource Planning (2019-2020 IRP) modeling. It also summarizes the methodology for how different data components are used within the RESOLVE model, which will be used to develop the 2019-2020 Reference System Plan.

The proposed inputs, assumptions, and methodologies will be applied to create optimal portfolios for the CAISO electric system in light of different forecasts of load growth, technology costs and potential, fuel costs, and policy constraints. In some cases, while default inputs and assumptions are proposed as listed in the ruling to which this document is appended, further options are presented here for early stakeholder feedback on potential 2019-2020 IRP scenarios and sensitivities. All proposals are subject to change in response to stakeholder feedback or as a result of unanticipated issues with data quality or availability.

1.1 Overview of the RESOLVE model

The high-level, long-term identification of new generation resources that meet California's policy goals is first developed using the RESOLVE resource optimization model. The CPUC uses RESOLVE to develop the Reference System Plan, a look into the future that identifies a portfolio of new 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 Plan because it is a publicly available and vetted tool. The CPUC uses the process of soliciting party feedback on this Inputs and Assumptions document to ensure that RESOLVE contains transparent, publicly available data sources and transparent methodologies to examine the long-term planning questions posed within our Integrated Resource Planning process.

Of note, CPUC also uses the Strategic Energy Risk Valuation Model (SERVM) as a separate model more specifically designed to examine system reliability once an optimal portfolio has been determined by RESOLVE. SERVM is a probabilistic system-reliability planning and production cost model. SERVM has more temporal and geographical granularity than RESOLVE and can therefore provide a higher fidelity assessment of operational performance. The 2019 IRP Reference System Plan development process will include activities to align the inputs and outputs of RESOLVE and SERVM to the extent possible through the use of common data sources to achieve reasonable agreement in outputs between the models.

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

RESOLVE can solve for:

- Optimal investments in renewable resources, energy storage technologies, demand response resources, distributed energy resources, and new thermal gas plants,

Subject to the following constraints:

- An annual constraint on delivered renewable energy that reflects Renewables Portfolio Standard (RPS) policy;
- An annual constraint on greenhouse gas emissions;
- A capacity adequacy constraint to maintain reliability;
- Operational restrictions on generators and resources; 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 CAISO 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 CAISO and the WECC, including the impacts of demand-side programs, load modifiers, and the impacts of electrification;

- **Section 3 (Baseline Resources)** summarizes assumptions on baseline resources. Baseline resources are existing or 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, incremental to the baseline resources that are assumed;
- **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 the operations of each of the resources represented in RESOLVE's internal hourly production simulation model;
- **Section 7 (Resource Adequacy Requirements)** discusses the constraints imposed on the RESOLVE portfolio to ensure system and local reliability needs are met, as well as assumptions regarding the contribution of each resource towards these requirements;
- **Section 8 (Greenhouse Gas Emissions and Renewables Portfolio Standard)** discusses assumptions and accounting used to characterize constraints on portfolio greenhouse gas emissions and renewables portfolio standard targets

1.3 Key Data Source Updates

Since the publication of the "CPUC 2017 IRP RESOLVE Documentation: Inputs & Assumptions"[1] in September 2017, CPUC staff and its consultant E3 have identified numerous inputs and assumptions to update within RESOLVE. The following list is not a comprehensive outline of all planned updates. Key updates will include:

- Updating the Load Forecast assumptions to align with the upcoming CEC 2018 Integrated Energy Policy (IEPR) California Energy Demand Forecast (Section 2.0);
- Updating the Baseline Resource assumptions to the most recent data available on existing and planned resources within and outside of CAISO (Section 3.0);
- Revising the source of capital cost assumptions and trajectories of solar PV, wind and potentially other renewable technologies to capture the rapidly-declining technology costs (Section 4.2);

[1] Found at: http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentB.RESOLVE_Inputs_Assumptions_2017-09-15.pdf

- Revising the capital cost assumptions of battery storage technologies to capture the rapidly-declining technology costs (Section 4.3);
- Adding behind-the-meter (BTM) storage as a candidate resource (Section 4.3); and
- Adding the ability to consider certain energy efficiency measures as candidate resources when modeling scenarios (Section 4.5).

1.4 Menu of Options

This I&A proposal differs from past versions in that it presents options for parties to consider for early comment on the inputs and assumptions that may be used in modeling of 2019-2020 IRP scenarios. In a 2019-2020 IRP Scenarios ruling to be issued in early 2019, staff will draw upon these options to propose a set of scenarios that incorporates selected data inputs for modeling in RESOLVE and SERVM.

Where multiple options are presented, the default ("base case") Reference System Plan (RSP) modeling assumptions are proposed as listed in the ruling to which this I&A document is appended. In this document, an asterisk denotes proposed assumptions for demand-side resources to be included in the base case. Party comments on base case modeling inputs and assumptions, as well as preliminary comments on inputs and assumptions for potential 2019-2020 IRP scenarios, are requested as described in the ruling.

2. Load Forecast

2.1 CAISO Balancing Authority Area

The primary source for CAISO load forecast inputs (both peak demand and total energy) in the 2019-2020 Reference System Plan will be the CEC's 2018 Integrated Energy Policy Report (IEPR) Demand Forecast, which is expected to be released Q1 of 2019.[2] The information presented in this section reflects the CPUC's anticipated data sources and assumptions but is subject to change based on stakeholder feedback, data availability and quality.

[2] In the 2017-2018 IRP cycle, most of the demand data was extracted from IEPR Forms 1.1c, 1.5a, 1.5b, and 1.2. References to IEPR demand data will be updated once the 2018 IEPR is released.

Many components of the CEC IEPR load 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;[3]
- Other electrification;
- Behind-the-meter PV;
- Non-PV self-generation (predominantly behind-the-meter combined heat and power);
- Energy efficiency; and
- Time of use (TOU) rate impacts.

Data sources for demand-side modifier assumptions will be discussed in subsequent sections. In some cases, staff present several potential options for party comment, as described in Section 1.4.

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. Recent versions of the IEPR Demand forecast assumed transmission and distribution losses of 7.3%. Losses will be updated if the IEPR includes updated loss assumptions.

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 in the 2019-2020 IRP cycle will be derived from retail sales reported in the CEC’s 2018 IEPR Demand Forecast along with accompanying information on the magnitude of embedded load modifiers. Creating a baseline consumption forecast enables different combinations of demand-side modifiers to be used in

[3] Building electrification estimates are not currently included in the 2018 IEPR’s Demand Forecast Update but are available from the CEC’s 2018 Deep Decarbonization in a High Renewables Future.

the IRP, including combinations that are not explored in the IEPR 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

CEC IEPR Retail Sales
+ Mid AAEE
+ Non-PV Self Generation
+ Behind-the-Meter PV
+ TOU rate effects
- Electric Vehicles
- Building and Other Electrification
= Baseline Consumption

2.1.2 Electric Vehicles

Staff proposes five potential options for forecasting future electric vehicle demand in the 2019-2020 IRP cycle:

- ***CEC 2018 IEPR Mid:** Based on the CEC's 2018 IEPR Mid Demand Forecast, this forecast will assume a moderate level of vehicle electrification.
- **CEC 2018 IEPR Low:** Based on the CEC's 2018 IEPR Low Demand Forecast, this forecast will assume a relatively low level of vehicle electrification.
- **CEC 2018 IEPR High:** Based on the CEC's 2018 IEPR High Demand Forecast, this forecast will assume a relatively high level of vehicle electrification.
- **Executive Order (B-48-18):** This forecast reflects the Governor's goal of 5 million zero-emission vehicles on the road in California by 2030.
- **CEC 2018 Deep Decarbonization – High Electrification:** This forecast reflects the High Electrification Scenario from the CEC's 2018 study, "Deep Decarbonization in a High Renewables Future," which assumes 6 million zero-emission vehicles on the road by

2030, including 1.5 million battery electric vehicles, 3.6 million plug-in hybrid electric vehicles, 0.8 million fuel cell vehicles, and 10% of trucks are hybrid and alternative fuel.[4]

To the extent that the fourth and fifth options are reasonably comparable with the IEPR 2018 Low, Mid, or High cases, they may be deemed duplicative and removed.

2.1.3 Building Electrification

Staff proposes two options for forecasting future building electrification demand in the 2019-2020 IRP scenarios effort:

- ***Minimal Incremental Building Electrification Measures**: This is consistent with previous versions of the IEPR demand forecast, which did not include building electrification, and with the CARB 2016 Scoping Plan "SP" scenario.
- **CEC 2018 Deep Decarbonization - High Electrification**: This load forecast, developed as part of a CEC study, assumes incremental electrification of residential and commercial HVAC and water heating.

2.1.4 Other Electrification

The forecast of electrification of "other" end uses (e.g. ports, and airport ground equipment) will be based on the CEC 2018 IEPR Demand Forecast.

2.1.5 Behind-the-Meter PV

The 2019-2020 IRP scenarios could include three options for behind-the-meter (BTM) PV adoption, each of which is based on the CEC's IEPR Demand Forecast. These options—Low, Mid, and High—correspond to the 2018 High, *Mid, and Low Demand Forecasts. Note that the IRP Low BTM PV forecast would be based on the IEPR High Demand Forecast and the IRP High BTM PV forecast would be based on the IEPR Low Demand Forecast. The naming of the IEPR forecasts corresponds to the relative level of retail load in each of the forecasts (higher amounts of BTM PV yield lower retail load).

The 2018 IEPR will include forecasts for "Additional Achievable Photovoltaic" (AAPV) adoption to account for behind-the-meter PV adoption attributable to 2019 Title 24 regulations for new

[4] Available at https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

homes. AAPV adoption is incremental to behind-the-meter PV adoption included in the IEPR demand forecast, and includes low-, *mid-, and high- scenarios. The 2019-2020 IRP cycle will include the AAPV options that are available in the 2018 IEPR.

2.1.6 Non-PV Self Generation

The forecast of non-PV self-generation (predominantly on-site combined heat & power (CHP) that does not export to the grid) will be based on the CEC 2018 IEPR Demand Forecast. CEC IEPR primarily models on-site CHP using projections based on past on-site CHP generation data. CHP units that export energy to the grid are separately discussed in section 3.

Staff may also update the forecast of self-generation CHP by comparing CEC IEPR forecasts with data requested from Load Serving Entities (LSEs). Staff will seek to match quantities of behind the BTM CHP facilities between CEC information and IOU submitted data.

2.1.7 Energy Efficiency

The 2019-2020 IRP scenarios study could include three options for varying levels of energy efficiency achievement among CAISO load-serving entities based on the scenarios included in the CEC's 2018 IEPR Demand Forecast.[5] "Additional Achievable Energy Efficiency" (AAEE) refers to efficiency savings beyond current committed programs. The options presented below are based on the IEPR Mid Demand Forecast - other IEPR AAEE scenarios could be included in sensitivity analyses as necessary.

- ***CEC IEPR – Mid AAEE (Scenario 3):** This forecast assumes that utilities continue to procure all cost-effective energy efficiency as identified under current programs.
- **CEC IEPR – High AAEE (Scenario 4):** In addition to including the load impact of the Mid AAEE, this option includes additional load reduction measures.
- **CEC IEPR – High Plus AAEE (Scenario 6):** This scenario includes savings incremental to the High AAEE due to SB 350 goals.

2.1.8 Time-of-Use Rate Impacts

The 2019-2020 IRP scenarios could include three options representing differing impacts of residential time-of-use (TOU) rate implementation on retail load which correspond to the low-, *mid-, and high- residential TOU scenarios from CEC's IEPR Demand Forecast.

[5] AAEE scenarios in the 2018 will be consistent with the 2017 Updated Demand Forecast AAEE Scenarios.

2.2 Other Zones

RESOLVE uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes six zones: four zones capturing California balancing authorities (BANC, CAISO, LADWP, and IID) and two zones that represent regional aggregations of out-of-state balancing authorities. The constituent balancing authorities included in each RESOLVE zone are shown in Table 6 found in Section 6.5.

Demand forecasts for zones outside CAISO will be developed by a process similar to CAISO forecasts. Forecasts will be taken from two sources:

- For each of the zones within California (LADWP, BANC, and IID) but external to CAISO, the CEC's IEPR Demand Forecast will be used.[6] Demand forecasts net of demand-side modifiers will be combined with the forecasted contributions of various load modifiers (behind the meter PV, energy efficiency, and electric vehicle adoption) available in the IEPR.
- For the zones outside of California (the Pacific Northwest and the Southwest), WECC's 2028 Anchor Data Set[7] will be used as the basis for load projections. Sales forecasts net of demand-side modifiers will be combined with available information in the 2028 Anchor Data Set related to demand-side modifier and consumption forecasts. This data will then be aggregated to the RESOLVE zones.

The demand forecasts for each non-CAISO zone will be grossed up for transmission and distribution losses. Staff will provide details to stakeholders on the methodology for developing load forecasts outside of CAISO in future materials or webinars.

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[6] See for Section 6.5 for details on the zonal topology used in RESOLVE.

[7] Version 2.0 of WECC's 2028 Anchor Data Set, posted October 22, 2018 and available here: https://www.wecc.biz/Reliability/WECC_2028ADS_V2.0_PublicData.zip, is the most recent version currently available. If an updated version is issued, 2019-2020 IRP inputs will be updated provided that there is adequate time to do so.

3. Baseline Resources

Baseline resources are existing or planned resources that are assumed to be available for dispatch in the year being modeled. The capacity of baseline resources is a fixed input to the portfolio optimization, but some baseline resources may be retired economically if retirement reduces system costs. Baseline resource capital costs are not considered in the RESOLVE optimization because these costs are sunk costs. An estimation of baseline resource capital costs may be used when calculating total revenue requirements and electricity rates. Existing baseline resources refer to units that are already online. Planned baseline resources refer to units that are not yet online but are assumed to be built within the planning horizon. Planned baseline resource costs are also treated as sunk costs.

A list of baseline resources and their attributes is under development for the 2019-2020 IRP cycle. The information presented in this section reflects the CPUC's anticipated data sources and assumptions but is subject to change based on stakeholder feedback, data availability, and data quality.

Baseline resources include:

- Existing Resources: Resources that have already been built and are currently available, net of expected future retirements.
- Planned Resources – under development: Resources that have contracts approved by the CPUC or the board of a community choice aggregator (CCA) and are far enough along in the development process that it is reasonable to assume that the resource will be completed. These resources are proposed to be discounted by 15 percent, consistent with historical contract failure rates.
- Planned Resources – not optimized: Future projected resource additions that are expected, but not appropriate for optimization (e.g., achievement of the CPUC storage target).
- Planned Resources – other: Future projected resource additions that were included in individual IRP filings, but that are somewhat generic and not represented by existing required targets or approved contracts. These resources are proposed to be discounted by 50 percent.
- Planned Resources – other balancing areas: The IRP process does not optimize resource additions for balancing areas outside CAISO, but changes in the generation portfolio of balancing areas outside of CAISO may influence portfolio selection

within the CAISO area. Consequently, baseline resources are added to other balancing areas to meet policy and reliability targets outside of CAISO.

Note that in the 2019-2020 IRP cycle, RESOLVE will be able to economically retire some, but not all, baseline resources.

Baseline resources will be assembled from the following primary sources:

- Individual LSE IRPs submitted in 2018. Commission staff may need to supplement the information provided with data requests to individual LSEs, to confirm contract, construction, and approval status for the existing and proposed resources.
- The list of generators currently operational inside the CAISO will be compiled from the most current CAISO Master Generating Capability List[8] published in Q1 of 2019. 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 will be supplemented by the CAISO MasterFile, a confidential data set with unit-specific operational attributes. The CAISO MasterFile also includes information related to dynamically scheduled generators. These generators are physically located outside of the CAISO but are able to participate in the CAISO market as if they were internal to CAISO. However, because they have no obligation to sell into CAISO they will be modeled as unspecified imports and will have no special priority given to their energy dispatch.
- Future renewable generators that will serve IOU-related CAISO load will be compiled from the RPS database maintained by CPUC staff and supplemented by data staff may request from energy service providers (ESPs) and CCAs. Information provided in individual LSE IRPs in 2018 will also be included, supplemented by additional data requests to LSEs, where needed. Additional information may be necessary to distinguish projects represented by Commission-approved or CCA board-approved contracts, from other generic planned renewable resources. The CEC will also assist staff in determining the full set of new generation under construction.
- For generators outside of CAISO, including areas within California such as LADWP and SMUD, generator listings and their associated operating information will be taken from

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

the most current version of the 2028 WECC Anchor Data Set (ADS) and supplemented by data from the CEC.

The sources for generator information are summarized in Table 2.

Table 2. Data Sources for Baseline Resources

Zone	Existing/Planned	Generator type	Dataset used
In CAISO	Existing	Renewable and Non-Renewable	CAISO Master Generating Capability List + CAISO Masterfile
In CAISO	Planned	Renewable	RPS Contract Database and Individual IRPs + supplementary data as necessary
In CAISO	Planned	Non-Renewable	WECC ADS
Out of CAISO	Existing and planned	Renewable and Non-Renewable	WECC ADS + CEC Renewable Net Short spreadsheet + Individual IRPs + supplementary data as necessary

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 MasterFile or the WECC ADS. For each zone, the following 5 resource classes can be modeled: Nuclear, Coal, Combined Cycle Gas Turbine (CCGT), Peaker, and Combined Heat and Power (CHP). Classes will be grouped and differentiated based on natural breakpoints observed in the distribution of data within class averages.

To more accurately reflect different classes of gas generators in the CAISO zone, CAISO's gas generators are further divided into subcategories. Resources will be grouped and differentiated into subcategories based on natural breakpoints in operating efficiency observed in the distribution of data within class averages[9]:

- 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 based on 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, most of which are scheduled to retire by 2020 to achieve compliance with the State Water Board's Once-Through-Cooling regulations.
- 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. CPUC staff is requesting data from the IOUs on CHP units in their respective service areas to determine contract details and whether the unit has a thermal host. Former CHP facilities that no longer have a thermal host and/or have transitioned to be dispatchable in response to market conditions will be classified under other categories (e.g. CCGT, Peaker, ST, etc.) depending on their characteristics.

The capacity of fossil-fueled and nuclear thermal generators that have formally announced retirement will be removed from baseline thermal capacity using the announced retirement schedule. Resources that have announced an intention to mothball will not be removed.

The 2019-2020 IRP version of RESOLVE will be able to retire baseline CAISO gas-fired resources economically within the optimization. This functionality was not present in the version of RESOLVE used in the 2017-2018 IRP cycle. Fixed operations and maintenance costs (fixed O&M)

[9] Staff will analyze the distribution of unit efficiencies across all units in a resource class (such as CAISO CCGTs) to determine the appropriate thresholds for subdividing each class.

of baseline gas-fired resources will be considered in RESOLVE's optimization logic such that these generators may be retired by the model, subject to reliability constraints, if it is cost-effective to do so. Fixed O&M costs will be derived from E3's 2014 review of capital costs for WECC, Capital Cost Review of Power Generation Technologies.[10]

This new functionality will allow for study of various scenarios. Staff proposes the following two options:

- **Economic Retirement or Retention**: Gas-fired generators will remain available to CAISO in perpetuity unless retirement has been formally announced – generators are not retired based on an assumed technical lifetime. In this option, the decision to retire is based on the cost to retain the resource and as compared to the cost of alternatives.
- ***Age-based Retirement**: Retirement decisions in this option would be based on generator age. For example, generators could be retired 40 years after their online date.

3.1.2 CAISO

Baseline natural gas, coal, and nuclear resources serving CAISO load will be drawn from a combination of the CAISO Master Generating Capability List and the CAISO MasterFile. Planned new generation for the CAISO area will be taken from the WECC 2028 Anchor Data Set. Other public data that the CPUC reviews, such as procurement applications and other CPUC proceedings, may supplement this information.

3.1.3 Other Zones

For zones external to the CAISO, the baseline gas, coal, and nuclear generation fleet will be based on the assumptions of the WECC 2028 Anchor Data Set. The ADS will be used to characterize the existing fleet in each zone as well as anticipated future changes, including announced retirements of coal generators and near-term planned additions included in utility integrated resource plans entities outside of CAISO file with their respective state commissions.[11] To maintain reliability and reflect the fact that coal fleet retirements are

[10] Available at: https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf. E3 updated the Review of Capital Costs for Generation Technologies in January of 2017 and found that natural gas resource costs remained stable since the 2014 version. https://www.wecc.biz/Administrative/2017-01-31%20E3%20WECC%20Capital%20Costs%20v1.pdf

[11] CPUC staff will compile a list of resources operating in each study zone for each study year and post it to the CPUC website prior to creation of the Reference System Plan in the 2019-2020 IRP cycle.

generally associated with a transition to natural gas, CCGTs will be added in each zone such that the total installed capacity of the thermal fleet does not decrease below its present level.

3.2 Renewables

Baseline renewable resources include all existing RPS eligible resources (solar, wind, biomass, geothermal and small hydro) in each zone. Renewable resources that are represented by contracts already approved by the Commission or CCA boards, as well as those under construction, will also be included in the baseline, though these resources are proposed to be discounted by 15 percent to approximate the historical rate of 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 under executed contracts with LSEs. As described above, information on existing renewable resources within CAISO will be compiled from the CAISO Master Generating Capability List and the CAISO MasterFile. Information on planned resources that are under development or with approved contacts is compiled from multiple sources:

- **CPUC IOU Contract Database:** The CPUC maintains a database of all of the IOUs' active and past contracting activities for renewable generation. Utilities submit monthly updates to this database with changes in contracting activities; the IRP will rely on the most up-to-date information in the contract database.
- **CEC POU Contract Reports:** Publicly owned utilities report their renewable contracting activities to the CEC. These reports provide detail on the facilities under contract to each POU and the expected duration of those contracts.
- **CEC Statewide Renewable Net Short spreadsheet:** The CEC tracks the total renewable generation in California, as well as out-of-state resources under contract to California entities, in an effort to quantify the total statewide renewable net short. The generator-specific information in this spreadsheet, including annual historical generation figures (MWh), is used as a supplemental source and a check to ensure that the combined portfolios of the California entities reflects the appropriate total amount of existing renewable generation.
- **Individual 2018 IRP filings and Supplementary Data Sources:** Commission staff will look to the resources included in the individual LSE IRP filings in 2018. The CEC, CCAs and ESPs may be consulted regarding generators holding contracts with POUs, CCAs, and

ESPs that may not already be included in the individual IRP filings or the other sources listed above.

3.2.2 Other Zones

3.2.2.1 Other California LSEs

For non-CAISO LSEs in California (those in the balancing authority areas IID, LADWP or BANC), the existing resources included in each renewable portfolio will be derived from the 2028 WECC Anchor Data Set and supplemented by the CEC's Statewide Renewable Net Short spreadsheet and contract reports provided by the POUs. In the CEC POU contract reports, publicly owned utilities submit annual updates to the CEC summarizing their renewable contracting activities. These reports provide detail on the facilities under contract to each POU and the expected duration of those contracts.

The 2019-2020 IRP cycle will assume that LSEs in each of the non-CAISO balancing authorities comply with the current RPS statute (60% RPS by 2030 and interim targets before 2030).[12] Portfolios of resources for each of these entities will be developed outside of RESOLVE and will be an input to the model. Future resources needed to continue compliance with the increasing RPS requirements will be based on existing integrated resource plans where available; where such information is unavailable, utility-scale solar resources will fill the renewable net short.

3.2.2.2 Non-California LSEs

RESOLVE assumes that neighboring states outside of California comply with their applicable RPS statutes to more accurately reflect the likely available out-of-state renewable potential. The portfolios of resources procured to meet each state's goals will be based on WECC's 2028 Anchor Data Set, developed by WECC staff with input from stakeholders.

Beyond 2028, renewable resources will be added in the Northwest and Southwest to maintain the same level of penetration reached in 2028 across the zone.[13] In the Northwest, these generic resources will be assumed to be new wind generation; in the Southwest, new generic resources beyond 2028 are assumed to be solar PV.

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[12] SB 100 was signed into law on September 10, 2018. SB 100 establishes a new RPS target of 60% by 2030. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100
[13] Note that Oregon has a 35 percent renewable requirement by 2030 for large utilities.

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 will be removed from the set of resources assumed to meet the policy goals of the non-California LSEs. To the extent the CAISO Master Generating Capability List identifies them as dynamically scheduled they will be modeled as if they are physically located inside the CAISO area and included in CAISO totals. Resources that are not dynamically scheduled into CAISO will be modeled as supplying RECs to CAISO RPS requirements, but energy from these projects will be added to the local zone's energy balance.

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 will be represented as providing energy to their local zone, with the exception of Hoover, which is split among the CAISO, LADWP, and SW zones in proportion to its ownership shares.

A fraction of the total Pacific Northwest hydro capacity will be made available to CAISO as a directly scheduled import. The quantity will be based on the amount of specified hydro imported into California will be based on historical import data.

3.4 Energy Storage

3.4.1 Pumped Storage

Existing pumped storage resources in CAISO will be based on the most current CAISO Master Generating Capability List. The storage capability of each facility, in MWh, will be based on input assumptions in CAISO's 2014 LTPP PLEXOS database. Because of RESOLVE'S 24-hour dispatch window, the capability to store energy beyond one day is not captured in RESOLVE.

3.4.2 Baseline Battery Storage

The 2019-2020 IRP cycle will 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, as Baseline resources. Specifically, 1,285 MW of battery storage will be modeled to fulfill the CPUC procurement targets established in response to AB 2514.[14] The remaining 40 MW of the total 1,325 MW of AB 2514 targets is the Lake Hodges Pumped Hydro project, which will be included with pumped storage as described above. Additional battery storage capacity not already installed or contracted will be split between wholesale and behind-the-meter installations.

In addition, Staff will look to CPUC procurement decisions and rolling IOU data request information submitted to the CPUC to identify the following:

- Energy storage procured towards any targets set by the CPUC in accordance with AB 2868, which allows for up to 500 MW of distributed energy storage systems. Only energy storage incremental to AB 2514 and already approved by the CPUC will be counted towards the baseline.[15]
- Additional behind-the-meter storage installations resulting from the Small Generator Incentive Program (SGIP) not already accounted for under AB 2514 or AB 2828 will be estimated using the SGIP Weekly Statewide Report.[16]
- Existing LSE storage procurement incremental to the policy-driven procurement mechanisms listed above. To obtain additional information, Commission staff will use the following sources:
    - Individual LSE IRPs filed in 2018 including planned additions, discounted at 50%.
    - CAISO Generator Interconnection Queue.[17]
    - Additional data requests to LSEs.
    - Industry press.

Reflecting current development practices, baseline storage resources are assumed to have an average duration of four hours.

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[14] AB 2514 was signed into law on September 29, 2010. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514
[15] AB 2868 was signed into law on September 26. 2016. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868
[16] Available at: https://www.selfgenca.com/home/resources/
[17] Available at: http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx

3.5 Demand Response

Shed (or "conventional") demand response reduces demand only during peak demand events. The 2019-2020 IRP will treat the IOUs' existing shed demand response programs as baseline resources. Shed demand response procured through the Demand Response Auction Mechanism (DRAM) will be included. The assumed peak load impact for each utility's programs will be based on the April 1, 2018 Demand Response Load Impact Report[18], and may be supplemented by the demand response resources economically participating in the CAISO market, drawn from the CAISO MasterFile, and by contracted DRAM capacity from DRAM III and DRAM IV advice letter filings.

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 multiple different types of resources, including natural gas generation, renewables, energy storage, and demand response. The optimal mix is a function of the relative costs and characteristics of the candidate resources 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.

Data for candidate resources are under development for the 2019-2020 IRP. The information presented in this section reflects the CPUC's anticipated data sources and assumptions but is subject to change based on stakeholder feedback, data availability, and data quality.

Generation profiles and operating characteristics for candidate resources are addressed in Section 6.

[18] 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.

4.1 Natural Gas

The 2019-2020 IRP will include three technology options for new natural gas generation: Advanced Combined Cycle (CCGT), Aeroderivative Combustion Turbine, and Reciprocating Engine. Each option has different costs, efficiency, and operational characteristics. The natural gas resource classes available to the model and their respective all-in fixed costs are derived from E3's 2014 review of capital costs for WECC, *Capital Cost Review of Power Generation Technologies*.[19] Natural gas fuel costs are discussed in Section 6.6. Operational assumptions for these plants are summarized in Section **Error! Reference source not found.**.

4.2 Renewables

RESOLVE is currently able to select from the following candidate renewable resources:

- Biomass
- Geothermal
- Solar Photovoltaic
- Onshore Wind

Candidate solar photovoltaic and onshore wind resources will be represented as either utility-scale or distributed. Candidate distributed resources will include different cost and performance assumptions from their utility-scale counterparts, as described in Section 6.2. Limited distributed wind resource potential was included in the 2017-2018 IRP, and the potential for this resource will likely be small in the 2019-2020 IRP cycle.

Offshore wind may be included as a new candidate resource in a sensitivity in the 2019-2020 IRP cycle. Assumptions about the potential, cost and performance of offshore wind will be developed with stakeholder input.

4.2.1 Potential

The CPUC is currently reviewing the 2017-2018 IRP assumptions on the potential of candidate renewable resources, which were based on data developed by Black & Veatch for the CPUC's

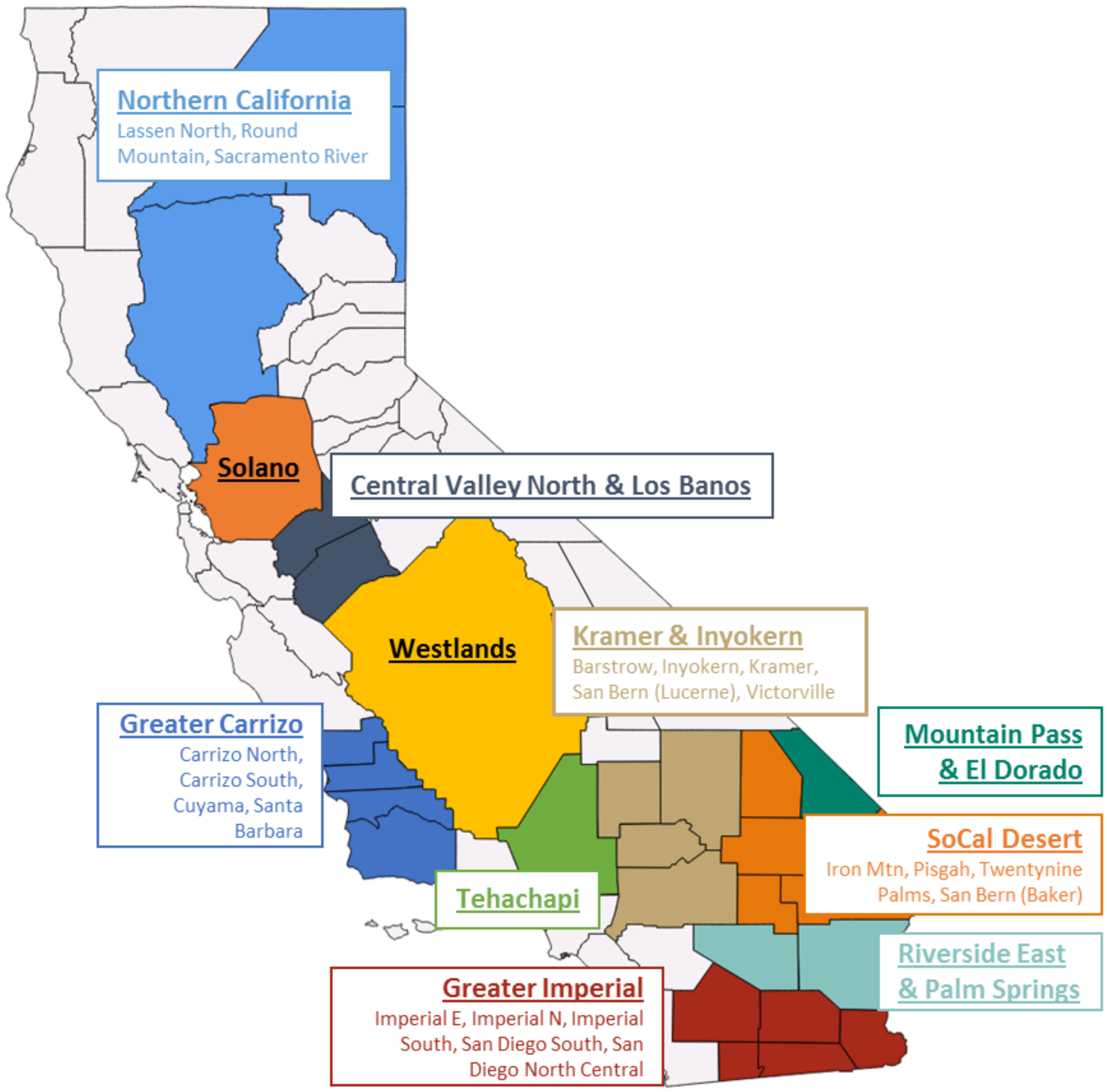
[19] Available at: https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf. E3 updated the Review of Capital Costs for Generation Technologies in January of 2017 and found that natural gas resource costs remained stable since the 2014 version. https://www.wecc.biz/Administrative/2017-01-31%20E3%20WECC%20Capital%20Costs%20v1.pdf

RPS Calculator v.6.3.[20] The Black & Veatch study an assessment of potentially viable sites and resource potential within those sites to determine an overall technical potential for each renewable technology. The information in this section may be revised for the 2019-2020 IRP based on updated information provided by the CEC or stakeholders.

Black & Veatch used 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." Within California, transmission zones are groupings of Competitive Renewable Energy Zones (CREZs). These groupings are shown in Figure 1. Candidate distributed solar and wind resources are assumed to be built locally and are therefore not assigned a transmission zone.

[20] 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 has been developed. This is because the IRP system plan development process is anticipated to replace the function previously served by the RPS Calculator.

Figure 1. In-state transmission zones in RESOLVE



The raw technical potential estimates developed by Black & Veatch are filtered through a set of environmental screens to produce the potential assumed available to RESOLVE. RESOLVE 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)[21] and San Joaquin Valley (SJV)
- **Minimum:** the potential when all the above screens are applied simultaneously

A more detailed explanation of each of these environmental screening is available in the Black & Veatch, RPS Calculator V6.3 Data Updates.[22] As described in Section 3.2.2.1, a small amount of the in-state renewable potential will be assumed to be developed by California entities outside of CAISO to meet incremental RPS needs and will therefore be made be unavailable to CAISO LSEs for development.

The available potential for out-of-state resources for the 2017-2018 IRP was also based primarily on Black & Veatch's assessment of renewable resource potential that identifies "high-quality" resources in Western Renewable Energy Zones (WREZs), which were aggregated to regional bundles. Some of these high-quality resources were assumed to require investments in new transmission to deliver to California loads. These estimates of resource potential were 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 2019-2020 IRP scenarios could include three "screens" for out-of-state resources[23]:

- **None:** no candidate out-of-state resources are included;
- ***Existing Tx Only:** only resources that can be interconnected on the existing transmission system and delivered to California are included as candidate resources; and
- **Existing & New Tx:** all out-of-state resources, including those requiring major investments in new transmission, are included as candidate resources.

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

[22] Black & Veach. 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

[23] 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

4.2.2 Resource Cost

NREL's 2018 Annual Technology Baseline[24] (ATB) will be used as the basis for renewable generation cost updates. In particular, because market data suggests notable cost reductions since the 2017-2018 IRP, the costs of solar PV and wind resources will be updated using the ATB for the 2019-2020 RSP. The planned approach for these updates is described below.

For resources that have not seen a material change in costs, 2017-2018 IRP cost assumptions may be used for the 2019-2020 IRP. The 2017-2018 IRP used data developed by Black & Veatch for the RPS Calculator v.6.3 in early 2013.[25]

4.2.2.1 Solar Capital Cost Assumptions

The ATB will be used to determine both capital costs and operating costs of solar PV resources within each forecast year. Both utility-scale and distributed solar PV cost projections will use ATB data.

Three capital cost trajectories could be developed based on the ATB report, where each projection would stem from the same estimated base value. The "Low" case would follow a more ambitious trajectory fueled by increased R&D funding, improvements in technology, and/or aggressive global demand, while the *"Mid" case would represent a medium level scenario. The "Constant" case would assume no improvements are made beyond present-day cost levels and would be assumed as the "High" case. The impact of tariffs on PV modules is not part of the ATB's base capital costs but is included as a capital cost adder in certain scenarios that could be utilized in the 2019-2020 IRP process.

The ATB's solar cost data are location-independent (developed to be free of geographical factors) and regional adjustments may be made to reflect California and out-of-state conditions, if material. The data is based on current industry practice of using a single-axis tracking system with a 1.35 inverter loading ratio for grid-scale solar and a fixed-tilt system with

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

[25] 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 has been developed. This is because the IRP system plan development process is anticipated to replace the function previously served by the RPS Calculator.

1.1 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 will be estimated based on an average ratio of O&M to capital expenditure (CAPEX) reported in the ATB. Low, *Mid, and High trajectories of O&M forecasts could be derived following this same methodology. This treatment implicitly assumes that the same historical correlations seen in O&M and CAPEX cost reductions will hold into the future. CAPEX, O&M, and future projections of distributed solar will also be derived using an analogous methodology.

4.2.2.2 Wind Capital Cost Assumptions

NREL's 2018 ATB also provides estimates of onshore wind costs. The ATB 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. Assumptions associated with the TRGs that resemble California and out-of-state wind conditions will be selected for use in the 2019-2020 IRP cycle. As for solar, the ATB provides base CAPEX and O&M values for wind, as well as three possible cost trajectories for consideration in potential scenarios: Low, *Mid, and Constant. The ATB's estimates of the O&M of wind do not include regional variants and are assumed constant 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.

4.2.3 Transmission Cost & Availability

Candidate renewable resources in RESOLVE may be selected for the portfolio either as **fully deliverable (FCDS)** resources or **energy only (EO)** resources, each representing a different classification of deliverability status by CAISO. The deliverability status assigned to each resource has implications for the transmission system as well as upon the value the resource provides to the system. The primary tradeoff between fully deliverable and energy only resources is the relative cost of transmission upgrades and the value of capacity provided by the resource: full deliverability allows a resource to count towards a load-serving entity's resource adequacy requirement but may require costly Deliverability Network Upgrades (DNUs); whereas energy only resources cannot be counted for capacity but do not require transmission upgrades for interconnection.

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 capacity that can be installed on the existing system while still receiving full capacity deliverability status.
- ***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).
- **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.

Assumptions on the cost and availability of transmission for renewable resources will be derived from outputs of the CAISO's annual transmission planning process, as contemplated in the 2010 memorandum of understanding on transmission planning.[26] Previous iterations of this information were incorporated into the RPS Calculator.[27] Most of these input assumptions are provided by CAISO; where CAISO has not studied costs of transmission system upgrades, generic cost estimates from the RPS Calculator will be used to supplement.

Candidate distributed solar and wind resources are assumed to be fully deliverable on the existing transmission system and do not incur additional transmission costs.

New out-of-state resources 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 will be based on assumptions developed for the CEC's Renewable Energy Transmission Initiative 2.0 (RETI 2.0).[28]

[26] http://www.caiso.com/Documents/100517DecisiononRevisedTransmissionPlanningProcess-CPUCMOU.pdf
[27] For example, see pages B22-B25 of the RPS Calculator 6.2 User Guide, available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10349
[28] https://www.energy.ca.gov/reti/

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

As in the 2017-2018 IRP cycle, the capital costs of candidate pumped storage resources for the 2019-2020 IRP will be based on *Lazard's Levelized Cost of Storage 2.0* (2016).[29] Pumped storage costs will be assumed to remain constant in real terms. Candidate pumped storage resources must have at least 12 hours of duration.

[29] 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.

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.[30] The types of costs included in each category are summarized in the table below.

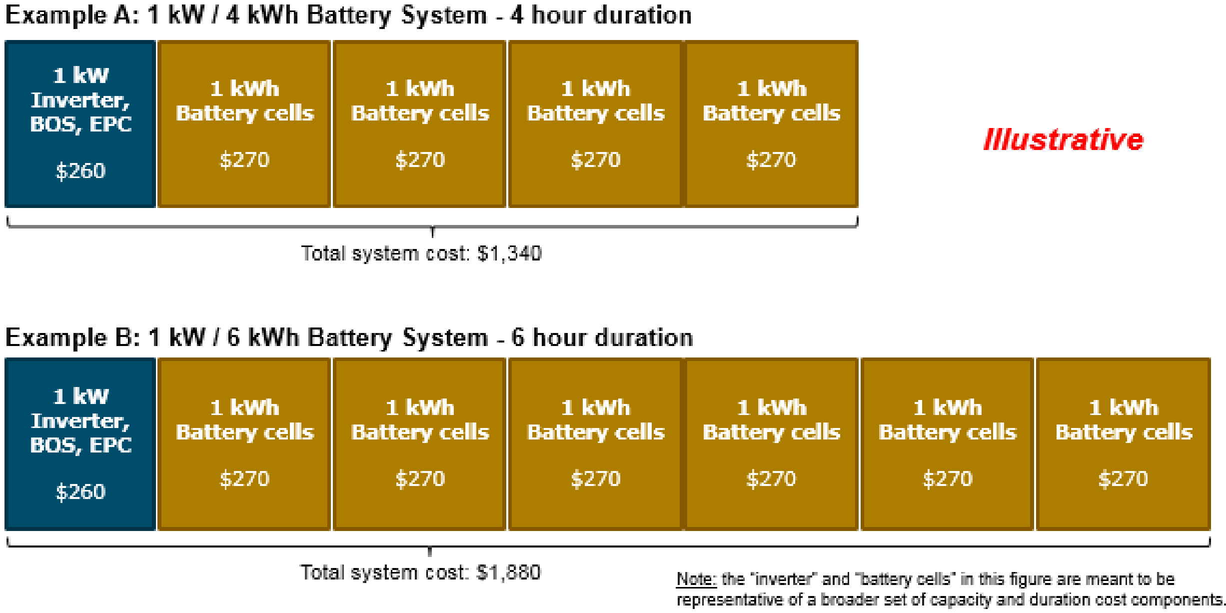
Table 3. Battery Storage Cost Categories

Cost category	**Battery storage system components**
Capacity (kW)	Inverter, switches and breakers, other balance of system and Engineering, procurement and construction (EPC) costs
Duration (kWh)	Battery cell modules, racking frame/cabinet, battery management system

The total cost of an energy storage system can be calculated by summing the cost for each capacity and duration "building block." This cost relationship is illustrated for two battery systems of different durations in the following figure.

[30] 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."

Figure 2. Illustrative example of methodology to calculate total capital costs for battery storage resources



Reflecting the hourly dispatch interval used in RESOLVE, candidate battery storage resources must have at least 1 hour of duration.

The 2019-2020 IRP cycle will include both wholesale and Behind-The-Meter (BTM) battery storage as candidate resources and will rely on storage cost assumptions from the most recent version of Lazard's Levelized Cost of Storage report.[31] Cost assumptions for candidate wholesale storage will be derived from Lazard's peaker replacement use case using the methodology described above. Both Li-ion and Flow technologies will be included as candidate wholesale battery storage resources. Candidate BTM battery storage will be assumed to be Li-ion technology, with costs derived from Lazard's commercial use case for Li-ion.

Given the uncertainty regarding future battery costs, the 2019-2020 IRP scenarios could include low, mid and high cost options to reflect a range of potential cost trajectories. In addition to breaking out capital costs between capacity and 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.

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[31] Currently Levelized Cost Storage 3.0 (2017) available at https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf. If Lazard's Levelized Cost Storage 4.0 (2018) becomes available before values in RESOLVE are finalized, values may be updated.

Forecasts for storage cost declines will be based on Lazard through 2022, the last year of the Lazard forecast. After 2022, it will be 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 will be applied equally to capital costs in the capacity and duration categories.

The default RESOLVE assumptions do 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 will be based on Lawrence Berkeley National Laboratory's report for the CPUC: *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study*.[32] The resource potential supply curve is based on data outputs from LBNL's DRPATH model, with the scenario assumptions outlined below in Table 4. DRPATH potential estimates are not incremental to existing demand response programs. Consequently, LSE demand response programs, including demand response procured through DRAM, will be removed from the DRPATH supply curve because these programs will be 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 will be removed from the supply curve in order of least to most expensive.

Table 4. 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

[32] 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

Energy Efficiency Scenario	Mid AAEE
Rate Scenario	Rate Mix 1—TOU and CPP (as defined by LBNL report)
Cost Framework	Gross

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 will continue to be based on Lawrence Berkeley National Laboratory's report for the CPUC: *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study*.[33] The resource potential supply curve is based on data outputs from LBNL's DRPATH model, with the scenario assumptions outlined below in Table 5.

Table 5. Scenario assumptions for LBNL's DRPATH model used to generate shift DR supply curve data for IRP modeling

Category	**Assumption**
Base year	2020
DR Availability Scenario	Medium

[33] 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

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

4.5 Energy Efficiency

Energy efficiency in the 2019-2020 IRP cycle will be represented as a load modifier by default (see Section 2.1.7) and therefore the level of efficiency will not be selected by the RESOLVE portfolio optimization. If energy efficiency is represented as a candidate resource in sensitivity studies, assumptions on the cost, performance, potential, and definition of candidate energy efficiency bundles will be based on Navigant's report for the CPUC: *IRP Technical Analysis: Considerations for Integrating Energy efficiency into California's Integrated Resource Plan -- Final Draft* (2018).[34]

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 2019-2020 IRP will assume financing is provided by an Independent Power Producer (IPP), which reflects current development practices in which most new

[34] Navigant, *IRP Technical Analysis: Considerations for Integrating Energy efficiency into California's Integrated Resource Plan -- Final Draft* (2018). Available as "Attachment: Navigant IRP Technical Analysis Report" at: https://pda.energydataweb.com/#!/documents/2083/view

resources in California are third-party owned and contracted with LSEs rather than financed by LSEs themselves. The pro forma determines the optimum IPP financing structure for each type of resource by maximizing the debt/equity ("D/E") ratio subject to three key constraints: 1) the expected asset return for a specific resource, which reflects asset risk factors, 2) the cost of investment grade corporate debt, and 3) a minimum debt service coverage ratio (DSCR) of 1.2, which represents an approximate benchmark criteria for investment grade debt. These assumptions are developed based on E3's expertise and experience working with developers in California. This approach yields different optimal financing structures for each resource due to differences in resource costs, tax incentives, depreciation schedules, financing lifetimes, etc. Ultimately, these different financing assumptions are reflective of the differences observed in real world transactions.

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.

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:

- **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes six zones: four zones capturing California balancing authorities and two zones that represent regional aggregations of out-of-state balancing authorities. The constituent balancing authorities included in each RESOLVE zone are shown in Table 6.

Table 6. Constituent balancing authorities in each RESOLVE zone

RESOLVE Zone	Balancing Authorities
BANC	Balancing Authority of Northern California (BANC) Turlock Irrigation District (TID)
CAISO	California Independent System Operator (CAISO)
LADWP	Los Angeles Department of Water and Power (LADWP)
IID	Imperial Irrigation District (IID)
NW	Avista Corporation (AVA) 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	*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)*

- **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 CT). 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. Additional constraints on operations (e.g. Pmin, Pmax, ramp rate limits, minimum up & down time) further limit the flexibility of each class' operations.
- **Co-optimization of energy & ancillary services:** RESOLVE dispatches generation to meet demand across the Western Interconnection while simultaneous reserving headroom and footroom on resources within CAISO to meet the contingency and flexibility reserve needs of the CAISO balancing authority.
- **Representative sampling of days:** RESOLVE differs from production cost models in that production cost models simulate a fixed set of resources, whereas RESOLVE can build or retire resources. 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 complete distribution of potential hydro conditions. An optimization algorithm is used to select the days and identify 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 simulating operations for only the 37 days.[35]

6.2 Load Profiles and & Renewable Generation Shapes

Load and renewable generation profiles ("shapes") characterize the hourly energy demand and the operations of each of the resources represented in 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 non-CAISO zones, the profiles are used without modification. For the CAISO zone, the final consumption load profile is created by adding appropriate shapes that either add to or subtract from load on an hourly basis to represent behind-the-meter PV, electric vehicles, energy efficiency, and time-of-use rate impacts to the baseline consumption profile.

6.2.1.1 Energy Efficiency Profiles

Energy efficiency will be modeled as a load-modifier (not a candidate resource) by default in the 2019-2020 IRP. Load-modifier energy efficiency hourly profiles will use data from the CEC's 2018 IEPR Demand Forecast. For any sensitivity studies that include energy efficiency measures as candidate resources, hourly profiles will be based on data developed by Navigant in their report for the CPUC: *IRP Technical Analysis: Considerations for Integrating Energy Efficiency into California's Integrated Resource Plan -- Final Draft* (2018).[36]

[35] A representative 37 days allows staff to run numerous scenarios (approximately 200 in 2017) to test various futures.

[36] Navigant, *IRP Technical Analysis: Considerations for Integrating Energy efficiency into California's Integrated* https://pda.energydataweb.com/#!/documents/2083/view

6.2.1.2 Electric Vehicle Load Profiles

EV load profiles included in the CEC 2018 IEPR Demand Forecast will be used as the default EV charging profiles in the 2019-2020 IRP. If additional analysis on charging profiles becomes available in time to include in the 2019-2020 IRP, these profiles may be included.

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 have flexible charging, 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. Unless new data becomes available, flexible charging assumptions from the 2017-2018 IRP cycle will be used for any flexible charging sensitivities in the 2019-2020 IRP. 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, will be reflected in IRP modeling. Building Electrification Load Profiles

The load profiles used to represent incremental building electrification will be based on end-use load shapes used in CEC's *Deep Decarbonization in a High Renewables Future* report. Within RESOLVE, the profile for building electrification is input as a representative hourly shape for each month. The profile is a composite of shapes associated with the following end uses: (1) residential cooking, (2) residential space heating, (3) residential water heating, (4) commercial space heating, and (5) commercial water heating. In the composite profile, each of these end uses is weighted in proportion to the relative amount of incremental electrification assumed in the Deep Decarbonization report.

6.2.1.3 Other Electrification Load Profiles

Other electrification profiles will be based on the CEC's 2018 IEPR.

6.2.1.4 Time-of-Use Rates Adjustment Profiles

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

6.2.2 Solar Profiles

Solar profiles for RESOLVE are created using a solar simulation tool made by E3. The tool uses standard solar modeling principles as laid out by Sandia's PV Performance Modeling Collaborative[37] to simulate PV production based on weather data from the National Solar Radiation Database (NSRDB)[38], and applies to both utility-scale and behind-the-meter solar.

For each of the resources modeled in RESOLVE, NSRDB data for five to twenty representative lat-lon coordinates (more for larger regions) is collected for the years 2007-2009. PV production profiles for each of these locations are then simulated for a fixed-tilt configuration, a single-axis tracking configuration, and a behind-the-meter rooftop configuration. The inverter loading ratio is assumed to be 1.3 for utility-scale systems, and 1.1 for behind-the-meter systems. Next, aggregate profiles for each resource and configuration (fixed-tilt, single-axis tracking, behind-the-meter) are obtained by taking the average of the representative locations. For utility scale resources, the final weighted-average profile is developed by assuming that utility-scale PV installations will be 25% fixed tilt and 75% tracking. Behind-the-meter systems are assumed to be 100% fixed tilt.

Before the solar profiles can be used in RESOLVE, they are scaled such that the weighted capacity factor of the 37 modeled days matches the capacity factor derived from the CPUC's RPS Calculator (Version 6.3) Supply Curve. For out-of-state resources, the target capacity factors will be based on data from the 2028 WECC Anchor Data Set. The reshaping is done by linearly scaling the shape up or down until the target capacity factor is met. When scaling up, the maximum normalized output is capped to 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.

6.2.3 Wind Profiles

Hourly shapes for wind resources are obtained from NREL's Wind Integration National Dataset ("WIND") Toolkit.[39] For each of the wind resources modeled in RESOLVE, wind production profiles for a set of representative locations is collected for the years 2007-2009. The profiles

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[37] Available at: **https://pvpmc.sandia.gov/** The modeling framework and assumptions on this website are very similar to what is used in NREL's PVWatts tool and NREL's System Advisor Model.
[38] See: **https://nsrdb.nrel.gov/current-version**
[39] See: https://www.nrel.gov/grid/wind-toolkit.htm

are then adjusted using a filter such that the weighted capacity factor of the 37 modeled days matches the capacity factor derived from the CPUC's RPS Calculator v.6.3 supply curve.[40] For out-of-state resources, the target capacity factors are based on data from the 2028 WECC Anchor Data Set. The filter is set up such that outputs at lower level are affected more (to represent better/worse turbine technology), while hourly ramps are preserved.

6.3 Operating Characteristics

6.3.1 Natural Gas, Coal, and Nuclear

The thermal fleet in RESOLVE is represented by a limited set of resource classes by zone that represent the capacity-weighted average for each resource class in that zone. Constraints on gas and coal plant operation are based on a linearized version of the unit commitment problem. The principal operating characteristics (Pmax, Pmin, Variable operations and maintenance costs - VO&M, heat rate, etc.) for each resource class will be compiled from a combination of January 2019 vintage version of the CAISO MasterFile and the 2028 Anchor Data Set. For the resources that are represented in the CAISO MasterFile, the non-confidential operating characteristics such as max capacity, in service data, fuel type, fuel curve, and location, will be aggregated by resource class. In the event that information is available for some generators but not others, information will be filled in from other appropriate or comparable generator class averages. Several plant types will be modeled using operational information from other sources:

- The **CAISO_Aero_CT** and **CAISO_Advanced_CCGT** operating characteristics will be based on manufacturer specifications of the latest available models of these class.
- The **CAISO_CHP** plant type will be modeled as a must-run resource at its full maximum capacity with an assumed net heat rate of 7,600 Btu/kWh, based on CARB's Scoping Plan assumptions for cogeneration.

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

[40] 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 has been developed. This is because the IRP system plan development process is anticipated to replace the function previously served by the RPS Calculator.

(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 high hydro availability and low loads.

6.3.2 Hydro

The operations of the hydro fleets in each region are constrained on each day by three constraints:

- **Daily energy budget:** the total amount of energy, in MWh, to be dispatched throughout the day; and
- **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; and
- **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 budget and operational range is based on actual CAISO daily operations on February 12, 2011).

Outside CAISO, where daily operational data was not available, 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.

6.3.3 Energy Storage

In RESOLVE's internal production simulation, storage devices can perform energy arbitrage or 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 will be able to perform energy arbitrage but will 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 over their full operable range almost instantly. The round trip efficiency for each storage technology (Li-ion, Flow and Pumped Hydro) will be based on the most recent information in the Lazard’s Levelized Cost of Storage report.

6.4 Operational Reserve Requirements

As described in

Table 7 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.

For generators, headroom and footroom are the difference between the current operating level and the maximum and minimum generation output, respectively. Reserves are modeled as mutually exclusive, meaning that headroom or footroom committed to one reserve product cannot be used towards other requirements.

Reserves are only modeled for the CAISO zone due to computational limitations. Given that the CAISO generation fleet does not include coal- or oil-fired generators,

Table 7 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 7. Reserve types modeled in RESOLVE

Product	Description	RESOLVE Requirement	Operating Limits
Frequency Response	Aside from system inertia, this is the fastest reserve type and is operated through governor or governor-like response.	770 MW of headroom is held in all hours on conventional hydroelectric, gas-fired, and battery resources. At least half of the headroom (385 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 and conventional hydroelectric resources are constrained by available headroom.
Regulation Up/Down	This is the second fastest reserve product modeled (4 sec – 5 min). 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. In practice, this is controlled by generators on Automated Generator Control (AGC), which get sent a signal based on the frequency deviations of the system.	The requirement is 1% of the hourly CAISO load both 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 the load forecast, as well as lumpy blocks of imports/exports/generator commitments, can be addressed in real-time.	In the 2017-2018 IRP, RESOLVE used an hourly requirement based on subhourly analysis that was done for one 33% and two 50% RPS cases in the CAISO system. This analysis parameterized the hourly load following requirements for each of the 37 RESOLVE model days based on the renewable penetration and diversity (high solar vs. diverse). The 2019-2020 IRP may include updated load following requirements.	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.

Spinning Reserve	This contingency reserve ensures that there are enough generators online in case of an outage or other contingency.	The default assumption is 3% of the hourly CAISO 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 generation is available 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 for these services is 20%. In other words, for every MW of regulation or load following up provided in a certain hour, we assume that 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. By default 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. Renewables are not assumed to provide any reserve product other than load following down.

6.5 Transmission Topology

The zonal transmission topology assumed in RESOLVE is based on compiled information from a number of public data sources. Where possible, transfer capability between zones is tied to rated WECC paths, per the WECC 2016 Path Catalog.[41] In instances where rating in one direction (e.g., West-to-East) is not defined, it is assumed to be symmetric with the opposite

[41] See https://www.wecc.biz/Reliability/Path Rating Logbooks.zip

direction. WECC path ratings are complemented by other available data, including scheduling total transfer capacity provided on the OASIS sites[42] of certain utilities and transmission owners. Where path data is not available, the sum of thermal ratings on lines connecting neighboring zones in WECC's nodal ADS cases has been used to allocate or provide information. This data is supplemented by other documents identified in past public filings online, as well as conversations with transmission engineers, to approximate actual operations to the extent possible.

RESOLVE also incorporates hurdle rates for transfers between zones; these hurdle rates are intended to capture the transactional friction to trade energy across neighboring transmission systems. The hurdle rates are based on CAISO's 2014 LTPP PLEXOS Case and are tied to the zone of export. In addition to these 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.[43]

In addition to the physical underlying transmission topology, RESOLVE also includes constraints on simultaneous net imports into, and exports out of CAISO. The net export constraint is included to capture explicitly the uncertainty in the size of the future potential market for California's exports of surplus renewable power.

6.6 Fuel Costs

The 2019-2020 IRP assumptions will include three options for fuel costs, each of which is based on a WECC burner tip price estimate from the CEC's NAMGas model run supporting the 2017 IEPR posted in April 2018.[44] Prices for each RESOLVE region are aggregated from NAMGas burner tip information using the average of the region of interest.

The 2019-2020 IRP assumptions will include four options for carbon costs, each of which will be based on revised IEPR Nominal Carbon Price Projections following the November 14, 2018 CARB allowance auction. The carbon projections will be assumed to increase 5% year-over-year in

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

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

[44] Available here: http://www.energy.ca.gov/2014publications/CEC-200-2014-008/April_2018_Model_CEC-200-2014-008.xlsm. If the 2018 IEPR update reruns NAMGas, the updated estimates will be used.

real terms. Nominal prices will be converted to real dollars assuming a constant 2% inflation rate. The model's default assumption is to only apply these carbon prices to resources in California, as well as unspecified imports into California.

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 CAISO balancing area 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 CAISO 1-in-2 peak demand in each year is calculated by adding or subtracting demand-side modifiers from the baseline consumption forecast (Section 2.1). 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. The capacity value of BTM PV is calculated using the ELCC value of solar as described below. The contribution of each type of generation resource to the 15% margin requirement depends on its performance characteristics and availability to produce power during the most constrained periods of the year; the treatment of each type of resource in the planning reserve margin constraint is discussed below.

7.1.1 Gas, Coal, and Nuclear Resources

The contribution of gas, coal, and nuclear generators to resource adequacy will be 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, will be calculated from the NQC list. 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 will be relatively close to 100%.

7.1.2 Hydro

The NQC of existing hydroelectric resources will be based on CAISO's NQC list.

7.1.3 Demand Response

The contribution of demand response resources to the resource adequacy requirement, including new shed DR resources selected by RESOLVE, will be assumed to be equal to the 1-in-2 ex ante peak load impact. Shift demand response selected by RESOLVE are currently not assumed to have an impact on the planning reserve margin.

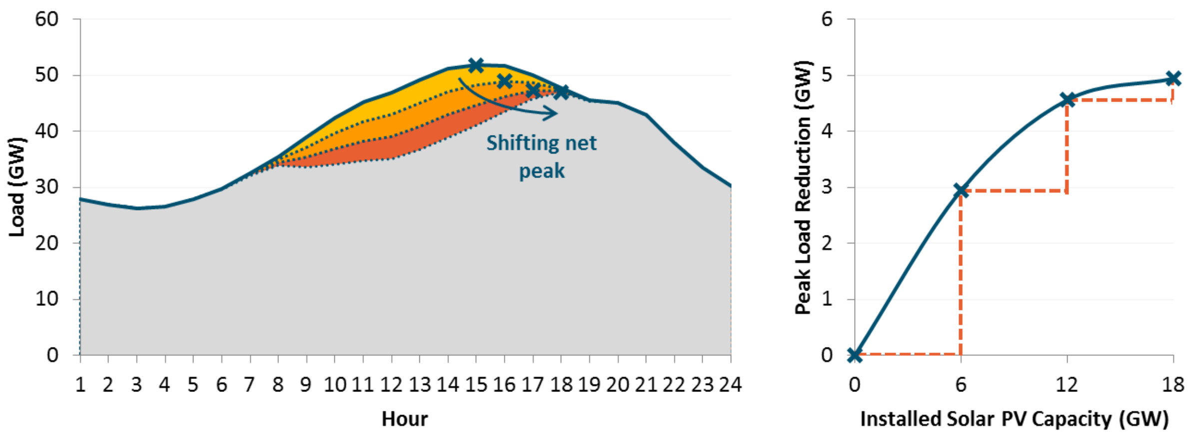
7.1.4 Renewables

Renewable resources with full capacity deliverability status (FCDS) are assumed to contribute to system resource adequacy requirements. Within RESOLVE, these resources fall into two categories: (1) firm, which includes all 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 firm renewables, each resources' contribution 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 an 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.

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 as well. 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 3. Because of this phenomenon, 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 3. Illustrative example of the declining marginal ELCC of solar PV with increasing penetration[45]



To approximate the cumulative ELCC of the CAISO's wind & 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.

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. For resources with durations under

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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] 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

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.

7.1.6 Imports

The contribution of imports to the resource adequacy requirement will be based on the CAISO's allocation of import capability for resource adequacy, which identifies a MW of import capability available for resource adequacy in CAISO.[47] Because CAISO's contractual shares of both Palo Verde and Hoover are modeled within CAISO in RESOLVE, the capacity of these resources will be deducted from the import capability to determine the contribution of imports to the Planning Reserve Margin.

7.2 Local Resource Adequacy

RESOLVE also 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 predominantly on the CAISO's Transmission Planning Process (TPP). The local capacity deficiencies identified across all LCR areas in the 2018-19 TPP will be represented in RESOLVE as an aggregated LCR need. If the 18-19 TPP does not identify any local areas with expected shortfalls in 2023 or 2028 (as occurred in the 2017-18 TPP[48]), RESOLVE will not include any incremental local capacity need. Retirement of capacity of resources located in LCR areas will result in the need for additional local capacity.

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[47] CAISO, "Step 6 – 2019 Assigned & Unassigned RA Import Capability on Branch Groups." Available at: http://www.caiso.com/Documents/Step6-2019AssignedandUnassignedRAImportCapabilityonBranchGroups.pdf
[48] CAISO 2017-'18 Transmission Plan, Appendix D: Local Capacity Technical Analysis, available at: http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf

8. Greenhouse Gas Emissions and Renewables Portfolio Standard

8.1 Greenhouse Gas Constraint

RESOLVE includes optionality to enforce a greenhouse gas (GHG) constraint on CAISO emissions. Staff plans to run the RESOLVE model to generate least-cost portfolios under different policy assumptions about the size of the electric sector's share, with respect to that of other sectors, in reducing statewide GHG emissions by 2030. To set the bookends of this analysis, staff will refer to the CARB-established GHG planning target range for the electric sector of 30–53 MMTCO2 statewide by 2030. This range was informed by the 2017 Scoping Plan Update and further supported by CPUC's IRP analysis in developing the 2017-2018 Reference System Plan.

Another consideration in determining points of analysis for electric sector GHG emissions is the recent passage of Senate Bill 100, which 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. Further to this, is the signing of Executive Order B-55-18 which requires achievement of statewide carbon neutrality as soon as possible, and no later than 2045. In 2017, IRP staff used RESOLVE to show that a 60% RPS by 2030 goal would fall within the range of 2030 GHG targets for the electric sector established by CARB. Staff does not yet have a recommendation on the implementation of the SB 100 goal or recent executive order in the 2019-2020 IRP, and invite party comment on the selection of GHG and/or RPS constraints for evaluation in 2019-2020 IRP modeling.

As in the previous IRP cycle, the statewide emissions of the electricity sector in this scenario will be multiplied by 81%—the share of ARB's forecasted 2030 allocation of emissions allowances to distribution utilities within the CAISO footprint[49]—to yield a target for CAISO LSEs.

8.2 Greenhouse Gas Accounting

RESOLVE tracks greenhouse gas emissions attributed to entities within the CAISO footprint using a method consistent with the California Air Resources Board's (CARB) regulation of the electric sector under California's cap & trade program.

[49] CARB's allowance allocation to distribution utilities from 2021-2030 is available here: https://www.arb.ca.gov/regact/2016/capandtrade16/ attach10.xlsx

8.2.1 CAISO Generators

The annual emissions of generators within the CAISO is calculated in RESOLVE as part of the dispatch simulation based on (1) the annual fuel consumed by each generator; and (2) an assumed carbon content for the corresponding fuel.

8.2.2 Imports to CAISO

RESOLVE attributes emissions to generation that is imported to CAISO based on the deemed emissions rate for unspecified imports as determined by CARB. The assumed carbon content of imports based on this deemed rate is 0.428 metric tons per MWh[50]—a rate slightly higher than the emissions rate of a combined cycle gas turbine.

Specified imports to CAISO are modeled as if the generator is located within CAISO, therefore any emissions associated with specified imports are included with emissions associated with CAISO generators. The majority of specified imports to CAISO are non-emitting resources.

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.[51] To retain consistency with CARB's Scoping Plan accounting conventions in the 2019-2020 IRP cycle, emissions associated with BTM CHP generation included in the IEPR forecast will be calculated and subtracted from the GHG constraint in RESOLVE.

8.3 RPS Constraint

8.3.1 RPS requirement

RESOLVE includes a constraint that enforces RPS compliance in CAISO 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. The RPS and greenhouse gas constraint

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

[51] 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.

(discussed in the previous section) both usually result in a portfolio with additional renewable generation to the baseline. 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.

As discussed in Section 3.2.2.2, renewable portfolios for zones outside of CAISO are specified as baseline resources and are designed to meet RPS requirements applicable to each zone.

The 2019-2020 IRP assumptions may also include levels of voluntary renewable commitments, which would increase the level of RPS resources procured beyond LSE's RPS requirements. If voluntary renewable commitments from corporations or LSE programs are included in the 2019-2020 IRP, the appropriate assumptions about volume will be developed with stakeholder input.

8.3.2 RPS Banking

As a compliance option for CAISO's RPS requirement, RESOLVE includes the ability to retire banked Renewable Energy Certificates (RECs) - renewable generation in excess of an LSE's RPS compliance requirements that can be redeemed during subsequent compliance periods. The volume of RECs that are banked at any point in time can be material, and the timing of REC redemption may significantly impact the selection of candidate resources. RESOLVE is able to model REC banking using two separate approaches, only one of which can be used in a given model run:

- A specified schedule of bank redemption (GWh in each year), calculated in advance of the RESOLVE optimization. This approach was used for the 2017-2018 IRP cycle.
- Bank usage is optimized within RESOLVE. A starting REC bank is specified, and bank deposits and withdrawals are made based on the economics of REC supply and demand within and between each RESOLVE investment period. Because RESOLVE models RPS compliance and REC banks at the CAISO-wide level, individual LSE banks cannot be considered within the optimization.

Given changing markets conditions, including the recent growth in RPS procurement of the CCAs, the CPUC is considering multiple options for representing RPS bank usage in the 2019-2020 IRP cycle:

- *Option 1 - Liquid trading: Represents a future in which LSEs will trade RECs with, or will transfer renewable contracts to, any other LSE to meet RPS requirements. This approach would likely lead to lower system-wide costs than Option 2 (described below) because

LSEs that do not have enough renewable generation under contract to meet RPS obligations would be able to buy RECs from LSEs that are long (i.e. have more renewable generation than necessary to meet their obligations), thereby reducing the need to develop new renewable projects in the near-term. Liquid REC trading could be represented in RESOLVE in two different ways:

  - 1A) A schedule of REC bank accrual and redemption would be calculated by comparing CAISO-wide RPS requirements to baseline physical renewable production potential. These inputs would be used to develop annual forecasts for REC bank accrual or usage within CAISO.
  - *1B) A starting REC bank representing current REC bank levels would be given to RESOLVE, and the schedule of bank accrual and redemption would be optimized within the model.

- Option 2 - Less liquidity: Represents a future in which in which LSEs only trade RECs with, or transfer renewable contracts to, other similar LSEs. For example, IOUs only trade with other IOUs, but do not trade with Community Choice Aggregators (CCAs). The analysis outlined in Option 1A would be performed three times, that is, once for each LSE type - the IOUs, CCAs, and ESPs. Data from the preferred system plan analysis would be used to inform how to divide baseline renewable production between the three LSE types. RESOLVE inputs for RPS procurement targets and REC bank redemption schedules would be adjusted based on the long or short positions of the three LSE types. In the near-term, some CCAs and other LSEs may not have enough renewables under contract to cover their RPS obligations, resulting in higher levels of near-term renewable build, potentially raising system costs relative to Option 1. Endogenous bank optimization would require details of REC and renewable generation at the LSE type level and is therefore not possible with Option 2 because RESOLVE can only optimize bank accrual and spend at a CAISO-wide level.

All options will require data from LSEs on the amount of RECs that are currently banked.

End of Attachment A