Senate Bill 350 Study

Volume IV: Renewable Energy Portfolio Analysis

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California ISO

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Energy+Environmental Economics

Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

List of Report Volumes

SB 350 Evaluation and Plan

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1 Executive Summary

1.1 Overview

E3 was retained by the California ISO ("ISO") to estimate the renewable energy procurement benefits of a regional market within the context of its studies conducted in response to Senate Bill 350 ("SB 350"). California Load-Serving Entities ("LSEs") must procure portfolios of renewable energy resources in order to comply with California's 50% Renewables Portfolio Standard ("RPS"). A regional market can provide renewable procurement benefits to California in at least two ways. Firstly, regional market operations can provide *integration benefits*, easing the burden of integrating such a large quantity of variable renewable energy resources, reducing the cost of compliance with a 50% RPS. Secondly, a regional transmission organization can facilitate the development of high-quality, remote resources—such as Class V wind resources in Wyoming and New Mexico—by providing grid access through its administration of a regional market and its authority to identify and allocate the costs of any needed new transmission facilities.

E3 identified optimal (i.e. least-cost) renewable portfolios under three scenarios intended to illuminate the two categories of benefit described above. This Volume describes the analysis that E3 undertook to estimate these benefits. E3's analysis addresses the renewable procurement benefits only; other benefits are estimated through the analyses described in the other volumes of this report.

1.2 Methodology

E3's Renewable Energy Solutions model ("RESOLVE") is an optimal investment and operational model designed to inform long-term planning questions around renewable integration in systems with high penetration levels of renewable energy. RESOLVE co-optimizes investment and dispatch over a multi-year horizon for a study area, in this case the California Independent System Operator ("ISO") footprint. RESOLVE solves for the optimal investments in renewable resources, various energy storage technologies, new gas plants, and gas plant retrofits subject to an annual constraint on delivered renewable energy that reflects the RPS policy, a capacity adequacy constraint to maintain reliability, simplified unit commitment constraints, and scenario-specific constraints on the ability to develop specific renewable resources.

The model is used to quantify the procurement cost of meeting California's RPS targets in the ISO balancing area in different scenarios representing different levels of regionalization. Results for the non-ISO entities in California are obtained by hand-selecting resources representative of plausible renewable procurement activities in each scenario rather than using RESOLVE for their portfolio determination.

1.3 Data & Inputs

Using the RESOLVE model described above, E3 developed renewable portfolios for three scenarios in California that each meet a 50% RPS in 2030:

+ **Current Practice 1 Scenario:** This scenario assumes that renewable energy procurement is largely from in-state resources, with 5,000 MW of out-of-state resources available over existing transmission. This scenario does not assume an expanded regional market.
+ **Regional 2 Scenario: Regional market operations with "current practice" renewable energy procurement policies:** This scenario assumes expanded regional markets, but assumes no change to current renewable energy procurement policies, i.e., procurement policies continue to favor in-state resources even when out-of-state resources are lower cost.
+ **Regional 3 Scenario: Regional market operations with regional procurement:** This scenario assumes expanded regional markets, as well as regional procurement of out-of-state resources over new transmission.

Table 1. Overview of the three scenarios modeled.

Scenarios	Current Practice 1	Regional 2	Regional 3
ISO export limit (MW)[1]	2,000	8,000	8,000
Procurement	Current Practice	Current Practice	WECC-wide
Operations	ISO	WECC-wide	WECC-wide

Input data on electricity demand, thermal resources and renewables is mostly based on public sources such as the CPUC's RPS calculator, the CEC's 2015 Integrated Energy Policy Report Update ("2015 IEPR"), the 2014 Long Term Procurement Planning proceeding ("LTPP") and the 2024 Transmission Expansion Planning Policy Committee ("TEPPC") Common Case.

A number of sensitivities are analyzed to verify the robustness of the results. Only the ISO inputs and results vary across these sensitivities, results for the non-ISO entities are held constant. The following sensitivities are tested:

[1] In the Current Practice 1 scenario, this limit is applied to all resources procured for California, including out-of-state resources that are delivered to California and must be re-exported. This means it is assumed that bilateral markets would accommodate the re-export of all prevailing existing imports (averaging 3,000–4,000 MW) plus export an additional 2,000 MW of (mostly intermittent) renewable resources. In Regional 2 and 3, this limit is relaxed due to the regional market's centralized, optimal dispatch and is applied as a physical transfer limit out of the current ISO footprint as a proxy for a physical simultaneous transfer limit (which does not has not yet been specified).

Table 2. Overview of sensitivities analyzed.

Sensitivity	Description
A. High coordination under bilateral markets	ISO simultaneous export limit is increased from 2,000 MW to 8,000 MW for Current Practice 1, while the procurement and operations are kept business-as-usual and ISO-wide ("Current Practice 1B")
B. High energy efficiency	The additional achievable energy efficiency (AAEE) is doubled by 2030.
C. High flexible loads	3,000 MW of 4-hour batteries are added in all scenarios.
D. Low portfolio diversity	Pumped hydro and geothermal are taken out of the portfolios and total California wind is restricted to 2,000 MW in all scenarios.
E. High rooftop PV	The total installed capacity of rooftop PV in the ISO balancing area is increased from 16 GW to 21 GW by 2030.
F. High out-of-state resource availability	Southwest solar RECs and Northwest wind RECs renewable potential is increased so that they account for up to half of the 50% RPS goal (ISO only, not non-ISO California entities), which equals to a renewable potential of 4,526 MW of Northwest wind RECs and 4,279 MW of Southwest solar RECs.
G. Low cost solar	Solar costs are reduced to $1/W-DC by 2025.
H. 55% RPS	The California RPS goal is increased to 55%.

1.4 Results

Regional markets result in lower renewable procurement costs for California across all scenarios. Renewable procurement cost savings are $680 million/year in 2030 under regional markets with current practices in renewable procurement (Regional 2). Procurement cost savings increase to $799 million/year in 2030 under regional markets with regional renewable procurement (Regional 3).

In both regionalization cases the larger, diversified footprint leads to lower curtailment and less overbuild to meet the RPS target, which lowers renewable procurement costs. Regional 3 shows that California's regional

procurement of Wyoming and New Mexico wind resources over new transmission results in additional cost savings because of the low cost of these resources, even with the additional transmission costs, and its diversification benefits.

The sensitivity results show the renewable procurement cost savings are relatively robust, with savings ranging from $391 to 1,341 million/year across all sensitivities. Sensitivities that increase the renewable integration challenges such as low portfolio diversity, higher RPS and high rooftop PV show an increase in procurement cost savings from regional coordination, while sensitivities that ease integration challenges and/or lower the cost of other resources such as high flexible loads and low solar costs decrease the savings. The highest procurement cost savings occur in the 55% RPS sensitivity, which might become the *de facto* base case after PG&E's recent decision to close Diablo canyon in 2025 and replace its output with renewables.[2]

The tables below show the main base case results, as well as a summary of the sensitivity results:

- Table 3 shows the annual statewide renewable procurement cost that California would be paying in 2030 for resources it procured to go from a 33% RPS to a 50% RPS in each scenario. The cost reflects the annualized procurement cost for all the renewable resources (including storage) to meet California's 50% RPS target by 2030, including transmission costs and an energy credit for REC resources.[3]

[2] See: http://www.utilitydive.com/news/pge-to-close-diablo-canyon-nuclear-plant-replace-it-with-renewables-effi/421297/

[3] *Pricing for REC resources is based on the PPA price of a new resource net of its energy value in local markets. Since this energy credit is not captured explicitly in PSO modeling, it is included here as an explicit adjustment. The energy value of all non-REC renewable resources is captured directly through PSO modeling.

- Table 4 shows the annual renewable curtailment in 2030 in the ISO area modeled by RESOLVE.
- Table 5 and Table 6 show the statewide portfolio that allows California to go from 33% to 50% RPS in 2030, both in MW of installed capacity and GWh of annual generation. The portfolio is additional to existing and planned renewable resources that are assumed to meet the 33% RPS in 2030.
- Table 7 shows a summary of the renewable procurement cost savings across all sensitivities. The cost numbers include the same metrics as the results in table 3, but all results are expressed relative to Current Practice 1 in order to show the procurement cost savings under a regional market.

Table 3. 2030 statewide annual renewable procurement cost and REC revenue ($MM).

Costs ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$3,297	$2,852	$2,347
Transmission Costs (new construction and wheeling; $M	$234	$0	$273
REC Revenue ($MM)	-$240	-$240	-$127
Net Total Costs	**$3,292**	**$2,612**	**$2,492**
Procurement Savings Relative to Current Practice 1		$680	$799

Table 4. 2030 annual renewable curtailment in ISO balancing area.

Renewable Energy Curtailment	Current Practice 1	Regional 2	Regional 3
Total Curtailment (GWh)	4,818	1,606	1,226
Curtailment as % of available RPS energy	4.5%	1.6%	1.2%

Table 5. 2030 statewide cumulative renewable portfolio additions in MW of installed capacity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	7,601	7,804	3,440
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,447	562	318
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	604	604	420
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,995
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,962
Total CA Resources	**11,101**	**10,204**	**5,840**
Total Out-of-State Resources	**5,551**	**5,166**	**7,694**
Total Renewable Resources	**16,652**	**15,370**	**13,534**
Batteries	472	-	-
Pumped Hydro	500	500	500

Table 6. 2030 statewide cumulative renewable portfolio additions in GWh of 2030 annual generation.

New Resources (GWh)	Current Practice 1	Regional 2	Regional 3
California Solar	21,482	22,147	9,827
California Wind	8,480	5,596	5,596
California Geothermal	3,942	3,942	3,942
Northwest Wind, Existing Transmission	4,056	1,574	891
Northwest Wind RECs	2,803	2,803	-
Utah Wind, Existing Transmission	1,693	1,693	1,177
Wyoming Wind, Existing Transmission	1,708	1,708	1,708
Wyoming Wind, New Transmission	-	-	8,037
Southwest Solar, Existing Transmission	-	1,489	1,489
Southwest Solar RECs	2,978	2,978	2,978
New Mexico Wind, Existing Transmission	3,416	3,416	3,416
New Mexico Wind, New Transmission	-	-	7,905
Total CA Resources	33,904	31,685	19,365
Total Out-of-State Resources	16,654	15,661	27,601
Total Renewable Resources	**50,558**	**47,346**	**46,966**
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 7. Summary of 2030 Sensitivity Results

Renewable procurement cost savings from regional market ($MM/year)		Regional 2 vs. Current Practice 1	Regional 3 vs. Current Practice 1
Base Case		$680	$799
A.	**High coordination under bilateral markets**	$391	$511
B.	**High energy efficiency**	$576	$692
C.	**High flexible loads**	$495	$616
D.	**Low portfolio diversity**	$895	$1,004
E.	**High rooftop PV**	$838	$944
F.	**High out-of-state resource availability**	$578	$661
G.	**Low cost solar**	$510	$647
H.	**55% RPS**	$1,164	$1,341

1.5 Conclusions

Regional markets result in significantly lower renewable procurement costs for California across all scenarios and sensitivities tested in the RESOLVE optimal investment model.

+ Renewable procurement cost savings are $680 million/year in 2030 under regional markets with current practices in renewable procurement.
+ Procurement cost savings are $799 million/year in 2030 under regional markets with regional renewable procurement.
+ Savings range is $391-1,341 million/year in 2030 under regional markets, across all sensitivities.

2 RESOLVE Model Methodology

2.1 Introduction

E3's Renewable Energy Solutions ("RESOLVE") Model is an optimal investment and operational model designed to inform long-term planning questions around renewables integration in California and other systems with high penetration levels of renewable energy. RESOLVE co-optimizes investment and dispatch over a multi-year horizon with one-hour dispatch resolution for a study area, in this case the California Independent System Operator ("ISO") footprint. The model incorporates a geographically coarse representation of neighboring regions in the West in order to characterize and constrain flows into and out of the ISO. RESOLVE solves for the optimal investments in renewable resources, various energy storage technologies, new gas plants, and gas plant retrofits subject to an annual constraint on delivered renewable energy that reflects the RPS policy, a capacity adequacy constraint to maintain reliability, constraints on operations that are based on a linearized version of the classic zonal unit commitment problem as well as feedback from ISO, and scenario-specific constraints on the ability to develop specific renewable resources.

The RESOLVE model is designed to answer planning and operational questions related to renewable resource integration. In general, these models fall along a spectrum from planning-oriented models with enough treatment of operations to characterize the value of resources in a traditional power system to detailed operational models that include full characterization of renewable integration challenges on multiple time scales but treat planning decisions as exogenous. The California Public Utilities Commission's ("CPUC's") RPS Calculator evaluates solutions on an annual basis without regard to the benefits of a long-term view. The Power System Optimizer ("PSO") model utilized by Brattle as part of this SB 350 analysis is an example of a detailed production simulation dispatch model which takes the renewable resource procurement decisions (along with all other investment or retirement decisions) as exogenous inputs. RESOLVE is used to develop the California renewable resources portfolios that are considered input for the PSO model in the SB 350 study. Below, we provide a description of the RESOLVE model.

2.2 Theory

One economic lens that can be used to evaluate various integration solutions is to consider the consequences of failing to secure the solutions. This is similar to the avoided cost framework, which has been applied broadly to cost-effectiveness questions in the electricity sector and other areas. In a flexibility-constrained system, the default consequence of failing to secure enough operational flexibility to deliver all of the available renewable energy is to curtail some amount of production in the time periods in which the system becomes constrained. In a jurisdiction with a binding renewable energy target, however, this curtailment may jeopardize the utility's ability to comply with the renewable energy target. In such a system a utility may need to procure enough renewables to produce in excess of the energy target in anticipation of curtailment events to ensure compliance with the Renewable Portfolio Standard ("RPS"). This "renewable overbuild" carries with it additional costs to the system. In these systems, the value of an integration solution, like energy storage, can be conceptualized as the renewable overbuild cost that can be avoided by using the solution to deliver a larger share of the available renewable energy. Cost effectiveness for an integration solution under these conditions may be established when the avoided renewable overbuild cost exceeds the cost of the integration solution.

Beyond cost effectiveness, this framework also allows for the determination of an optimal solution by examining the costs and benefits of increasing levels of investment in the integration solutions. If a single integration solution is available to the system, the optimal investment in that solution is the investment level at which the marginal cost of the solution is equal to the marginal benefit in terms of avoided renewable overbuild of the solution. However, as described above, many different strategies can be pursued and the value of each solution will depend on its individual performance characteristics as well as the rest of the solution portfolio. RESOLVE provides a single optimization model to explicitly treat the cost and behavior of specific solutions as well as the interactions between solutions.

2.3 Methodology

The RESOLVE model co-optimizes investment and operational decisions over several years in order to identify least-cost portfolios for meeting renewable energy targets. This section describes the RESOLVE model in terms of its temporal and geographical resolution, characterization of system operations, and investment decisions. Particular attention is placed on topics that are unique to an investment model that seeks to examine renewable integration challenges, including: renewables selection; reserve requirements; energy storage; flexible loads; and day selection and weighting for operational modeling.

2.3.1 TEMPORAL SCOPE AND RESOLUTION

In this analysis, investment decisions are made with 5-year resolution between 2015 and 2030. Operational decisions are made with hourly resolution on a subset of independent days modeled within each investment year. Modeled days are selected to best reflect the long run distributions of key variables like load, wind, solar, and hydro availability. The day selection and weighting methodology is described in more detail below.

For each year, the user defines the portfolio of resources (including conventional, renewable, and storage) that are available to the system without incurring additional fixed costs – these include existing resources, resources that have already been approved, and contracted resources, net of planned retirements. In addition to these resources, the model may be given the option to select additional resources or retrofit existing resources in each year in order to meet an RPS requirement, fulfill a resource adequacy need, or to reduce the total cost. Fixed costs for selected resources are annualized using technology-specific financing assumptions and costs are incurred for new investments over the remaining duration of the simulation. The objective function reflects the net present value of all fixed and operating costs over the simulation horizon, plus an additional *N* years, where the *N* years following the last year in the simulation are assumed to have the same annual costs as the last simulated year, *T*. When the investment decision resolution is coarser than one year, the weights applied to each modeled year in the objective function are determined by approximating the fixed and operating costs in un-modeled years using linear interpolations of the costs in the surrounding modeled years.

2.3.1.1 Operating Day Selection and Weighting

To reduce the problem size, it is necessary to select a subset of days for which operations can be modeled. In order to accurately characterize economic relationships between operational and investment decisions, the selected days and the weights applied to their cost terms in the objective function must reflect the distributions of key variables. In the analysis described here, distributions of the following parameters were specifically of interest: hourly load, hourly wind production, hourly solar production, hourly net load, and daily hydropower availability. In addition, the selection of the modeled days sought to accurately characterize: the number of days per month, average monthly hydropower availability, and site-specific annual capacity factors for key renewable resources.

To select and weight the days according to these criteria or target parameters, an optimization problem was constructed. To construct the problem, a vector, *b*, was created that contained all of the target parameter values and described each target parameter distribution with a set of elements, each of which represents the probability that the parameter falls within a discrete bin. The target values can be constructed from the full set of days that the problem may select or from an even longer historical record if data is available.

For each of the days that can be selected, a vector, a, is produced to represent the contribution of the conditions on that day to each of the target parameters. For example, if b_i represents the number of hours in a year in which the load is anticipated to fall within a specified range, a_{ij} will represent the number of hours in day j that the load falls within that range. The target parameters vector, b, may therefore be represented by a linear combination of the day-specific vectors, a_j, and the day weights can be determined with an optimization problem that minimizes the sum of the square errors of this linear combination. An additional term is included in the objective function to reduce the number of days selected with very small weights and a coefficient, c, was applied to this term to tune the number of days for which the selected weight exceeded a threshold. The optimization problem was formulated as follows:

$$\begin{aligned} &\mathit{minimize} \quad \sum_i \left[\left(\sum_j a_{ij} w_j \right) - b_i \right]^2 - c \sum_j w_j^2 \\ &\mathit{subject\ to} \quad \sum_j w_j = 365 \end{aligned}$$

The resulting weights can then be filtered based on the chosen threshold to yield a representative subset of days. This method can be modified based on the specific needs of the problem. For example, in this analysis, while the hourly net load distribution was included in the target parameter vector, cross-correlations between variables were not explicitly treated.

2.3.2 GEOGRAPHIC SCOPE AND RESOLUTION

While RESOLVE selects investment decisions only for the region of interest, in this case the ISO, operations in a highly interconnected region are influenced by circumstances outside the region. For example, the conditions in the Northwest, Southwest, and Los Angeles Department of Water and Power ("LADWP") regions influence the ISO dispatch via economic imports and exports. To capture these effects, RESOLVE includes a zonal dispatch topology with interactions between the zones characterized by a linear transport model. Both the magnitudes of the flows and the ramps in flows over various durations can be constrained based on the scenario. Hurdle rates can also be applied to represent friction between balancing areas. Simultaneous flow constraints can also be applied over collections of interties to constrain interactions with neighboring regions.

The zonal topology for the analysis is shown in Figure 1 – the ISO footprint is the primary zone and the Northwest and Southwest regions and LADWP balancing area are the secondary zones. The Northwest region includes the region encompassed by the U.S. portion of the Northwest Power Pool, plus the Balancing Area of the Northern California. The Southwest region includes New Mexico, Arizona, Southern Nevada, and the Imperial Irrigation District. The flow constraints applied in this analysis are summarized in Table 1. Negative numbers in the table represent exports from California, while positive values represent imports.

Figure 1. Zonal topology

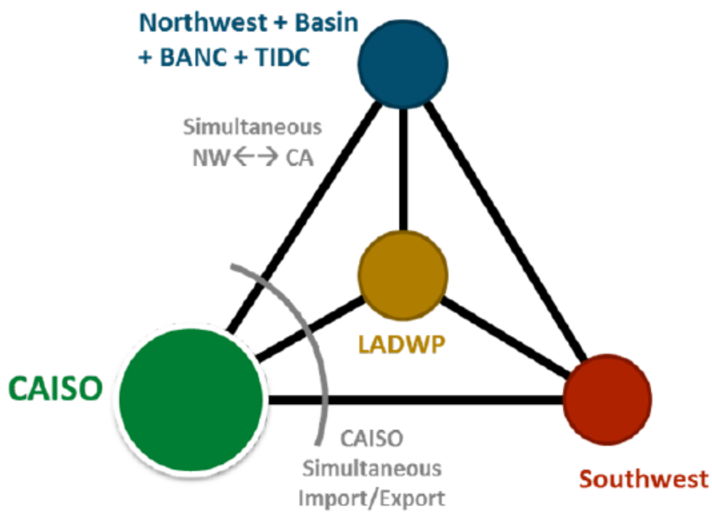


Table 8. Flow constraints between zones and simultaneous flow constraints (negative numbers reflect flows in opposite direction).

Path	Minimum Flow (MW)	Maximum Flow (MW)
SW → ISO	-7,250	6,785
NW → ISO	-5,171	6,364
LADWP → ISO	-2,045	4,186
LADWP → NW	-,2826	2,963
SW → LADWP	-3,373	3,373
NW → SW	-1,480	1,465
Simultaneous NW → CA	-7,934	9,390
ISO Simultaneous Import	-8,000 to -2,000	10,068

2.3.3 INVESTMENT DECISIONS

2.3.3.1 Renewable Resources

The RESOLVE model was designed primarily to investigate investment driven by a renewable energy target. This constraint, which is applied based on the policy goal each year, ensures that the procured renewable energy net of any renewable energy curtailed in operations exceeds a MWh target based on the load or retail sales in that year. RESOLVE allows the user to specify a set of resources that must be built in each modeled year as well as additional renewable resources that may be selected by the optimization. These options allow for the design of portfolios that take into consideration factors such as environmental or institutional barriers to development.

While a traditional capacity-expansion model might take into consideration the technology cost, transmission cost, capacity factor of candidate renewable resources, RESOLVE also considers the energy value through avoided operational costs, capacity value through avoided resource adequacy build, and the integration value through avoided renewable resource overbuild. These three factors depend on the timing and variability of the renewable resource availability as well as the operational capabilities of the rest of the system. To account for all of these factors, each candidate resource is characterized by its hourly capacity factor over the subset of modeled days, installed cost on a per kW basis, location within a set of transmission development zones, and maximum resource potential, in MW.

Transmission development zones are characterized by a threshold total renewable build, above which a $/MW-yr cost is applied to incremental renewable build to reflect the annualized cost of additional transmission build to support interconnecting renewables on to the high-voltage transmission system. Multiple renewable resources may be assigned to the same transmission development zone (for example some zones may have both solar and wind resources that can be developed) and the selection of resources within each zone will depend on their relative net cost and the combined impact of resource build on incurred transmission development costs.

2.3.3.2 Integration Solutions

RESOLVE is also given the option to invest in various renewables integration solutions such as different types of energy storage or gas resources. Renewable curtailment occurs when the system is not capable of accommodating all of the procured renewable energy in hourly operations. While there is no explicit cost penalty applied to the curtailment observed in the system dispatch, the implicit cost is the cost of overbuilding renewable resources to replace the curtailed energy and ensure compliance with the renewable energy target. This renewable overbuild cost is the primary renewable integration cost experienced by the system and may be reduced by investment in integration solutions.

2.3.3.3 Resource Portfolios in Secondary Zones

RESOLVE selects investment decisions only for the primary zone, in this case the ISO. The resource portfolios for the secondary zones, in this case the Northwest, Southwest and LADWP, must be designed to ensure resource adequacy and renewable policy compliance, and selected as a RESOLVE input. These decisions, which are exogenous from the planner's perspective in the primary (ISO) zone are also exogenous to the model. For each year of the simulation, each secondary zone is characterized by the hourly load, hourly renewable availability, hydro availability, and conventional resource stack. Because the model only selects investment decisions for the primary zone, the resource portfolios for the secondary zones must be designed to ensure resource adequacy and renewable policy compliance outside of RESOLVE. These decisions, which are exogenous from the planner's perspective in the primary zone are also exogenous to the model. For the SB 350 project, renewable resources were hand-selected selected for the California municipal utilities outside the ISO's balancing area to ensure compliance with a 50% RPS by 2030 for these regions.

2.3.4 SYSTEM OPERATIONAL CONSTRAINTS

2.3.4.1 General

RESOLVE requires that sufficient generation is dispatched to meet load in each hour in each modeled zone. In addition, dispatch in each zone is subject to a number of constraints related to the technical capabilities of the fleets of generators within the zone, which are described in detail below. In general, dispatch in each zone must satisfy

$$\sum_{i\in I_z} x_h^{it} + w_h^{zt} + \sum_{\omega\in Z}\sum_{j\in J_{z\omega}} \left(R_{jt}^{tot} r_h^j - q_h^{jt}\right) + \sum_{k\in K_z^{in}} f_h^{kt} - \sum_{k\in K_z^{out}} f_h^{kt}$$

$$+x_h^{dzt} - x_h^{czt} + u_h^{zt} - o_h^{zt} = l_h^{zt}$$

where l_h^{zt} is the load in zone *z*, year *t*, and hour *h*; x_h^{it} is the generation from thermal resource *i*; I_z is the set of all thermal resources in zone *z*; R_{jt}^{tot} is the total installed capacity of renewable resource *j*; q_h^{jt} is the curtailment of renewable resource j; $J_{z\omega}$ is the set of all renewable resources located in zone *z* and contracted to zone ω; w_h^{zt} is hydro generation in zone *z*; x_h^{dzt} and x_h^{czt} are the energy discharged from energy storage and energy extracted from the grid to charge energy storage respectively; u_h^{zt} is the undergeneration and o_h^{zt} is other overgeneration in zone z; f_h^{kt} is the flow over line k, K_z^{in} and K_z^{out} are the sets of all transmission lines flowing into and out of zone z, respectively.

2.3.4.2 Reserve Requirements and Provision

RESOLVE requires upward and downward load following reserves to be held in each hour in order to ensure that the system has adequate flexibility to meet sub-hourly fluctuations and to accommodate forecast errors. In real systems, reserve requirements depend non-linearly on the composition of the renewable portfolio and the renewable output in each hour. To avoid additional computational complexity, RESOLVE requires the user to specify the hourly reserve requirements for each scenario. In the ISO example, the methodology described in NREL the Eastern Wind Integration and Transmission Study ("EWITS")[4] was used to derive hourly reserve requirements associated with today's renewable portfolio, a 33% RPS portfolio in 2020, and two potential 50% RPS portfolios in 2030 – one dominated by solar resources and one with a more diverse mix of solar, wind, and geothermal resources. For each scenario, the user selects which set of reserve requirements to use for 2020 and 2030 and the reserve requirements in each year are approximated via linear interpolation.

The user specifies whether each technology is capable of providing flexibility reserves, and the reserve provisions available from each technology are described above. Upward flexibility reserve violations are penalized at a very high cost to ensure adequate commitment of resources to meet upward

[4] National Renewable Energy Laboratory, "Eastern Wind Integration and Transmission Study," Revised February 2011. Available at: http://www.nrel.gov/docs/fy11osti/47078.pdf

flexibility challenges within the hour. However, downward reserve shortages are not penalized as operating violations. RESOLVE assumes that a portion of downward reserve needs – 50% in the cases analyzed for this study – can be managed via real-time curtailment of renewable resources. This behavior is approximated in RESOLVE through a parameterization of the sub-hourly imbalances similar to that implemented in E3's REFLEX model.[5] Sub-hourly curtailment in RESOLVE is a function of the reserve provisions held, as described in Hargreaves et al (2014). If the entire downward reserve requirement is held, then it is anticipated that the system will experience no additional renewable curtailment in real-time to manage sub-hourly imbalances. If the downward reserve requirement cannot be met, then the expected real-time curtailment can be approximated.

This formulation allows the dispatch model to directly trade-off between the cost of holding additional reserves (including the cost of committing additional units and operating these units at less efficient set points) against the cost of experiencing some amount of expected sub-hourly renewable curtailment by shorting the downward reserve provision. Just as with curtailment experienced on the hourly level, expected sub-hourly curtailment is not directly penalized in the objective function, but does result in additional cost to the system by requiring additional renewable overbuild for policy compliance.

In addition, RESOLVE allows the user to constrain the absolute amount of observed sub-hourly curtailment in each hour to reflect potential limits in the participation of renewable resources in real-time markets or real-time dispatch

[5] Hargreaves, J., E. Hart, R. Jones, A. Olson, "REFLEX: An Adapted Production Simulation Methodology for Flexible Capacity Planning," IEEE Transactions of Power Systems, Volume:PP, Issue: 99, September 2014, pp 1 – 10.

decisions. These limits are typically set as a fixed fraction of the available energy from curtailable renewable resources in each hour.

Finally, RESOLVE allows the user to apply a minimum constraint on the fraction of the downward reserve requirement held with conventional units. Specifying a limit on the ability of renewables to provide the necessary downward reserves ensures that that the model will carry a portion of the needed reserves on conventional resources such as hydro or thermal resources, or on energy storage resources. While full participation of renewable resources in real-time markets may be the lowest cost approach to managing downward flexibility challenges, a system operator may seek to keep some downward flexibility across the conventional fleet as a backstop in case the full response from renewable resources does not materialize in real-time.

2.3.4.3 Other requirements

Additional operational constraints are imposed based on specific system needs. For example, for this SB 350 project, additional constraints were designed for consistency with modeling efforts by the ISO for the California Long-Term Procurement Plan ("LTPP"). These include: a frequency response requirement of 775MW in each hour, half of which can met upward capability on hydro resources and the other half of which can be met with other dispatchable units on the system including renewables and energy storage resources.

2.3.4.4 Resource Adequacy

In addition to hourly operational constraints, RESOLVE enforces an annual resource adequacy constraint based on a parameterization of resource adequacy needs to maintain reliability. The parametrization was developed based on simulations of loss of load probability ("LOLP") in the ISO system under high-solar and diverse renewable portfolio scenarios and takes into account the expected load-carrying capability ("ELCC") of the renewable portfolio. The constraint requires that sufficient conventional capacity is available to meet net load plus a certain percentage above net load. In this study, the capacity adequacy constraint is not binding and does not cause procurement of conventional capacity.

2.3.5 OPERATIONAL CONSTRAINTS

2.3.5.1 Thermal Resources

For large systems such as the ISO's, in RESOLVE thermal resources are aggregated into homogenous fleet of units that share a common unit size, heat rate curve, minimum stable operating level, minimum up and down time, maximum ramp rate, and ability to provide reserves. In each hour, dispatch decisions are made for both the number of committed units and the aggregate set point of the committed units in the fleet. For sufficiently large systems, such as the ISO, commitment decisions are represented as continuous variables. For smaller systems, specific units may be modeled with integer commitment variables. For the continuous commitment problem, reserve requirements ensure differentiation between the committed capacity of each fleet and its aggregated set point. The ability of each fleet to provide upward reserves, $\overline{x}_h^{it}$, is:

$$x_h^{it} + \overline{x}_h^{it} \leq n_h^{it} x_{max}^{i} \quad \forall i, t, h$$

where n_h^{it} is the number of committed units and x_{max}^i is the unit size. Downward reserve provision is limited by:

$$x_h^{it} - \underline{x}_h^{it} \geq n_h^{it} x_{min}^i \quad \forall i, t, h$$

where x_{min}^i is the minimum stable level of each unit.

Upward reserve requirements are imposed as firm constraints to maintain reliable operations, but downward reserve shortages may be experienced by the system with implications for renewable curtailment (See section 2.3.4.2). The primary impact of holding generators at set points that accommodate reserve provisions is the increased fuel burn associated with operating at less efficient set points. This impact is approximated in RESOLVE through a linear fuel burn function that depends on both the number of committed units and the aggregate set point of the fleet:

$$g_h^{it} = e_i^1 x_h^{it} + e_i^0 n_h^{it}$$

where g_h^{it} is the fuel burn and e_i^1 and e_i^0 are technology-specific parameters.

Minimum up and down time constraints are approximated for fleets of resources in RESOLVE. In addition, startup and shutdown costs are incurred as the number of committed units change from hour to hour, and constraints to approximate minimum up and down times for thermal generator types are imposed.

Must-run resources are modeled with flat hourly output based on the installed capacity and a de-rate factor applied to each modeled day based on user-defined maintenance schedules. Maintenance schedules for must-run units are designed to overlap with periods of the highest anticipated oversupply conditions so that must run resources may avoid further exacerbating oversupply conditions in these times of year. Maintenance and forced outages may be treated for any fleet through the daily de-rate factor. However, in the analysis presented here, maintenance schedules for dispatchable resources were not explicitly modeled – it was instead assumed that maintenance on these systems could be scheduled around the utilization patterns identified by RESOLVE's dispatch solution.

2.3.5.2 Hydroelectric Resources

Hydroelectric resources are dispatched in the model at no variable cost, subject to: an equality constraint on the daily hydro energy; daily minimum and maximum outputs constraints; and multi-hour ramping constraints. These constraints are intended to reflect seasonal environmental and other constraints placed on the hydro system that are unrelated to power generation. The daily energy, minimum, and maximum constraints are derived from historical data from the specific modeled days. Ramping constraints, if imposed, can be derived based on a percentile of ramping events observed over a long historical record. Hydro resources may contribute to both upward and downward flexibility reserve requirements.

2.3.5.3 Energy Storage

Each storage technology is characterized by a round-trip efficiency, per unit discharging capacity cost ($/kW), per unit energy storage reservoir or maximum state of charge cost ($/kWh), and for some resources, maximum available capacity. Energy storage investment decisions are made separately for discharging capacity and reservoir capacity or maximum state of charge. Dispatch from each energy storage resource is modeled by explicitly tracking the hourly charging rate, discharging rate, and state-of-charge of energy storage systems based on technology-specific parameters and constraints. Reserves can be provided from storage devices over the full range of maximum charging to maximum discharging. This assumption is consistent with the capabilities of battery systems, but overstates the flexibility of pumped storage systems, which can only provide reserves in pumping mode if variable speed pumps are installed, typically pump storage units cannot switch between pumping and generating on the time scales required for reserve products, and are subject to minimum pumping and minimum generating constraints that effectively impose a deadband on the resource operational range.

An adjustment to the state of charge in RESOLVE is assumed that represents the cumulative impact of providing flexibility reserves with the device over the course of the hour. For example, if a storage device provides upward reserves throughout the hour, it is anticipated that over the course of the hour the storage device will be called upon to increase its discharge rate and/or decrease its charge rate to help balance the grid. These sub-hourly dispatch adjustments will decrease the state of charge at the end of the hour. Similarly, providing downward reserves will lead to an increase in the state of charge at the end of

the hour. Little is known about how energy storage resources will be dispatched on sub-hourly timescales in highly renewable systems – this behavior will depend on storage device bidding strategies and technical considerations like degradation. Rather than model these factors explicitly, RESOLVE approximates the impact of sub-hourly dispatch with a tuning parameter, which represents the average deviation from hourly schedules experienced as a fraction of the energy storage reserve provision.

3 SB 350 Study Assumptions

3.1 Scenario Definitions and Assumptions

Using the RESOLVE model described above, E3 developed renewable portfolios for three scenarios in California. Each of the scenarios meets a 50% renewables portfolio standard ("RPS") in 2030. The scenarios are:

+ **Current Practice 1 Scenario: Current practice:** This scenario assumes that renewable energy procurement is largely from in-state resources, with 5,000 MW of out-of-state resources available over existing transmission. This scenario does not assume an expanded regional market.
+ **Regional 2 Scenario: Regional market operations with "current practice" renewable energy procurement policies:** This scenario assumes expanded regional markets, but assumes no change to current renewable energy procurement policies, i.e., procurement policies continue to favor in-state resources even when out-of-state resources are lower cost.
+ **Regional 3 Scenario: Regional market operations with regional procurement:** This scenario assumes expanded regional markets, as well as regional procurement of out-of-state resources over new transmission.

3.2 Load Forecast

The ISO load forecast is based on the 2015 IEPR Mid AAEE load forecast (January 2016 Update)[6]. 2026-2030 data (not in IEPR) is extrapolated using the 2024-2026 average annual growth rate. The IEPR forecast includes estimates for energy efficiency, electric vehicles, and behind-the-meter solar, among others (see below).

Table 9. 2015 IEPR Mid Baseline Mid AAEE Forecast for ISO

Metric (all units in GWh/yr)	2015	2020	2025	2030
Mid Baseline Demand Before Any Modifiers	**309,930**	**328,805**	**343,450**	**360,166**
Demand Adders	**481**	**2,344**	**6,299**	**12,280**
Electric Vehicles	481	1,785	4,954	9,910
Other Electrification	-	311	849	1,553
Climate Change Impacts	-	248	497	818
Demand Reducers	**92,511**	**118,954**	**140,076**	**170,485**
Self-Generation Photovoltaic*	5,297	10,139	16,964	28,465
Self-Generation Other Private Generation	11,934	13,528	13,962	14,281
AAEE Savings	137	8,838	16,600	26,208
Committed EE Savings	75,143	86,449	92,550	101,530
2015 IEPR Managed Sales (retail)	**217,900**	**212,195**	**209,673**	**201,961**
2015 IEPR Managed Net Energy for Load**	**235,011**	**228,748**	**225,877**	**217,302**

* De-rated by 2% to account for losses incurred when exporting customer PV (different from IEPR forecast which assumes no losses). The equivalent installed capacity in 2030 is 16,649 MW (ac)

** Grossed up for losses at 7.33%.

[6] Available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03

3.2.1 HOURLY LOAD SHAPES

Load shapes for the ISO zone were built up from end use-specific hourly shapes. Hourly load shapes for non-transportation ISO loads are based on historical data. These non-transportation ISO loads are then adjusted to account for the impact of implementing mandatory residential time-of-use rates by 2020. Furthermore, the impact of smart charging and day-time charging availability of light-duty electric vehicles ("EV") is reflected in an EV load shape that is added onto the adjusted non-transportation load shape.

Load shapes in other zones, including non-ISO California entities, are based on the TEPPC 2024 Common Case, with fixed annual load growth rates extrapolated to 2030.

3.2.1.1 Time-of-use rates and flexible loads

The effect of time-of-use rates is implemented as a fixed 24-hour load shape adjustment for every month. The load shape adjustment for January is shown in the table below; other months show essentially the same load shape adjustment. By 2030, we assume there is up to about 1,000 MW of load shifting, from the evening hours into the early morning and midday hours. Aside from this time-of-use rate adjustment, demand response and other flexible loads are not explicitly modeled in this iteration of the analysis.

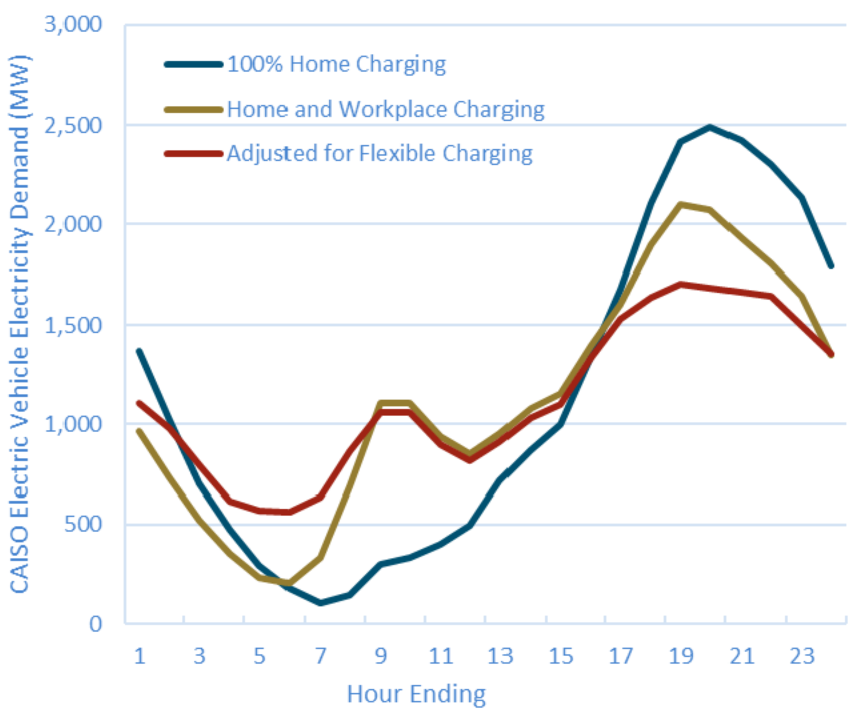
Table 10. Hourly load shape adjustment (MW) due to time-of-use rates in ISO in the month of January for the years 2015, 2020, 2025 and 2030.

Hour	2015	2020	2025	2030
1	0	319	321	264
2	0	319	321	264
3	0	319	321	264
4	0	319	321	264
5	0	319	321	264
6	0	319	321	264
7	0	319	321	264
8	0	418	435	410
9	0	517	549	556
10	0	616	663	701
11	0	715	777	847
12	0	813	891	992
13	0	715	777	992
14	0	616	663	847
15	0	287	305	437
16	0	-42	-53	27
17	0	-371	-412	-383
18	0	-601	-656	-793
19	0	-831	-900	-1057
20	0	-831	-900	-1057
21	0	-831	-900	-1057
22	0	-831	-900	-1057
23	0	-831	-900	-1057
24	0	-601	-656	-1057

3.2.1.2 Electric Vehicle Load Profiles

EV load profiles are created using an EV charging model developed by E3, which modify the base load profile assumptions. The charging model is based on the 2009 National Household Transportation Survey ("NHTS"), a dataset on personal travel behavior. The model translates travel behavior into aggregate EV load shapes by weekday/weekend-day, charging strategy, and charging location availability. The weekend/weekday shapes are aggregated and normalized into month hour shapes by charging location availability. A blend is created by assuming 20% of drivers have charging infrastructure only available at home, while 80% of drivers have charging infrastructure available both at home and at the workplace. Last, the evening peak of this blended shape is shifted partly to the early morning hours to reflect smart charging. To obtain the actual load profile, the normalized profile is multiplied with the annual EV load. The resulting ISO EV Load shape for January 2030 is shown below.

Figure 2. ISO Electric Vehicle charging Profile (January 2030 example)



3.3 Renewable Generation Shapes

Hourly shapes for wind resources were obtained from NREL's Wind Integration National Dataset ("WIND") Toolkit[7] and adjusted using a filter in order to match the site-specific capacity factors in the CPUC's RPS Calculator (version 6.1)[8]. Hourly solar shapes were obtained using NREL's Solar Prospector[9] and scaled/filtered to match capacity factors in the CPUC's RPS Calculator (version 6.1).

3.4 Thermal Resources

The thermal resource stack in the ISO footprint is characterized based on the 2014 Long Term Procurement Plan modeling undertaken by the ISO and adjusted to reflect retirements that are scheduled to occur between after 2015. Thermal resources are grouped by technology and performance characteristics (heat rate, minimum stable level, and ramp rate) into fleets of similarly behaving resources which RESOLVE treats as homogenous. The resulting thermal fleets are summarized in Table 2. Outside of ISO, thermal fleets are developed for each region based on the 2024 TEPPC Common Case. Coal retirements planned for between 2024 and 2030 are also reflected in each resource stack, assuming a one-for-one replacement with combined cycle gas units. A coarser aggregation approach is applied to non-ISO regions in order to reduce

[7] The Wind Toolkit and associated materials can be obtained from NREL at: http://www.nrel.gov/electricity/transmission/wind_toolkit.html
[8] The RPS Calculator and associated materials can be obtained from the CPUC at: http://www.cpuc.ca.gov/RPS_Calculator/
[9] The Solar Prospector and associated materials can be obtained from NREL at: http://maps.nrel.gov/node/10

computational complexity. The conventional resource installed capacities by year are listed in Table 11.

Table 11. Performance characteristics for planned (i.e. exogenously selected) resources in each zone

Planned Resources	Pmax (MW)	Pmin (MW)	Max Ramp (%Pmax/hr)	Min Up/Down Time (hrs)	Startup Cost ($/MW)	Fuel Burn Slope (MMBtu/MWh)	Fuel Burn Intercept (MMBtu/unit)
ISO Resources							
CHP	39 3	39.2	0%	24	0.0	6.845	0
Nuclear	572	572	0%	24	0.0	9.576	0
CCGT1	393	175	100%	6	50.9	6.268	288
CCGT2	410	118	100%	6	48.8	6.050	427
Gas Peaker1	64.4	28.0	100%	1	77.6	8.262	74
Gas Peaker2	44 9	16.3	100%	1	111.5	7.577	122
Steam Turbine	358	28.7	100%	6	10.0	9.302	212
Demand Response	1	0	100%	0	0	0	0
Northwest Resources							
Nuclear	1,170	995	0%	24	-	10.907	-
Coal	344	137	100%	24	14.54	9.222	283
CCGT	337	166	100%	6	14.83	6.614	219
Gas Peaker	30	11	100%	1	662.71	9.381	39
Southwest Resources							
Nuclear	953	953	0%	24	-	10.544	-
Coal	427	171	100%	24	11.70	9.151	354
CCGT	391	199	100%	6	12.77	6.619	315
Gas Peaker	71	25	100%	1	279.97	8.795	141
LADWP Resources							
Nuclear	152	152	0%	24	-	10.544	-
Coal	820	328	100%	24	6.10	8.656	644
CCGT	230	123	100%	6	22	6.967	65
Gas Peaker	79.1	36	100%	1	253	8.857	88

Table 12. Installed capacities of planned (i.e. exogenously selected) resources in each zone across all scenarios

Resource	Planned Installed Capacity (MW)			
	2015	2020	2025	2030
ISO Resources				
CHP	4,006	4,006	4,006	4,006
Nuclear	2,862	2,862	1,742	622
CCGT1	10,705	9,307	10,207	10,207
CCGT2	5,328	5,328	5,328	5,328
Gas Peaker1	3,471	3,471	3,671	3,671
Gas Peaker2	3,200	3,046	2,916	2,916
Steam Turbine	10,388	6,314	0	0
Demand Response	2,088	2,169	2,179	2,179
Northwest Resources				
Nuclear	1,170	1,170	1,170	1,170
Coal	12,784	10,962	9,665	7,970
CCGT	12,034	14,296	15,593	17,288
Gas Peaker	4,193	4,135	4,135	4,050
Southwest Resources				
Nuclear	2,858	2,858	2,858	2,858
Coal	12,391	10,080	9,241	9,241
CCGT	21,130	23,445	24,169	24,169
Gas Peaker	8,885	11,329	12,903	12,528
LADWP Resources				
Nuclear	457	457	457	457
Coal	1,640	1,640	0	0
CCGT	2,069	2,069	3,709	3,709
Gas Peaker	2,742	2,769	2,531	2,531

3.5 ISO Base Portfolio (33% RPS)

The model starts from a ISO base portfolio that meets 33% RPS in 2030. This portfolio is based on contracted resources in the CPUC's RPS Calculator (version 6.1) and consists mostly of currently existing renewable resources. All results shown in the results section of this report are additional to this "existing" base portfolio, and lift the total amount of RPS renewable energy from 33% to 50%.

Table 13. ISO Base Portfolio: Renewables to meet 33% RPS in the ISO balancing area in 2030.

Renewable Resources	Installed Capacity (MW)	Annual Energy (GWh)
ISO Solar	9,890	18,259
ISO Wind	5,259	15,859
ISO Geothermal	1,117	9,785
ISO Small Hydro	429	3754
ISO Biomass	794	6955
Northwest Wind	2,186	6,073
Northwest Biomass	32	280
Northwest Geothermal	1	6
Southwest Solar	197	380
Imperial Geothermal	449	3933
Total ISO Resources	**17,489**	**54,612**
Total Non-ISO Resources	**2,417**	**10,672**
Total Renewable Resources	**20,354**	**65,284**
Other Resources	**Installed Capacity (MW)**	**Annual Energy (GWh)**
Energy Storage	3,157	-
Behind-the-meter Rooftop PV	16,649	29,046

3.6 In-State Renewable Potential

The California renewable potential considered in RESOLVE is based on the CPUC's RPS Calculator (version 6.1) with several modifications:

+ The RPS Calculator's granular resource potential data has been aggregated to eleven California resource zones, each of which consists of one or more Competitive Renewable Energy Zones (CREZs), shown in Figure 3; and
+ The potential resources available in each zone have been limited based on discussions with the Aspen Environmental Group, which identified environmental constraints that may make development in specific areas challenging.

Because of these modifications to the RPS Calculator's resource potential assumptions, the "potential" considered in RESOLVE does not reflect the maximum technical potential for each resource available in California, but rather is intended to reflect a reasonable upper limit for development in each zone that accounts for environmental, political, and transmission-related factors.

The renewable potential assumed in each of these resource zones, which is considered available in all scenarios, is summarized in Table 14.

Figure 3. California resource zones included in RESOLVE model

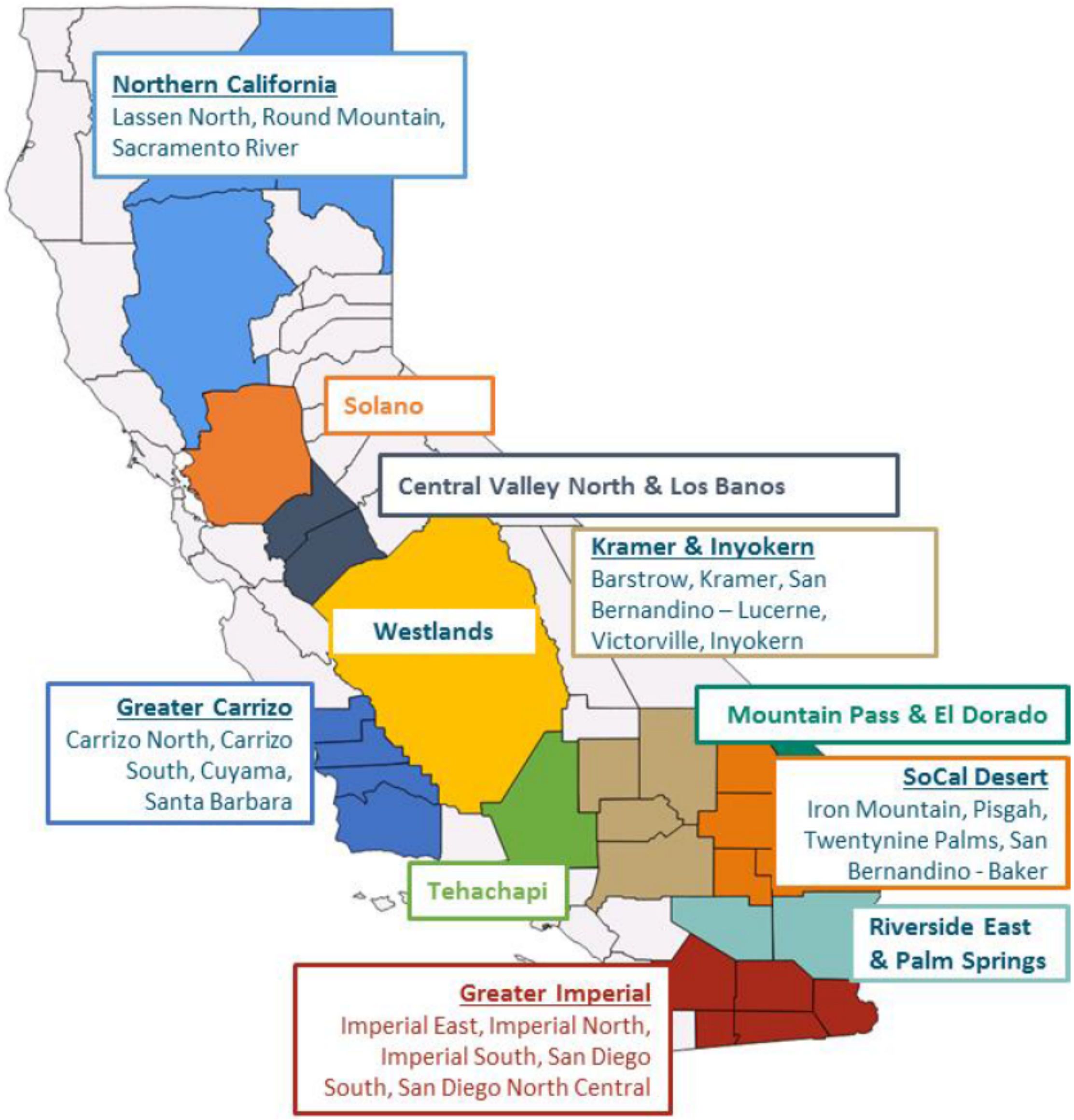


Table 14. California renewable potential considered in RESOLVE (additional to existing renewables)

Resource	Zone	Potential (MW)
Geothermal	Greater Imperial	1,384
	Northern California	424
	Subtotal	***1,808***
Solar PV	Central Valley & Los Banos	1,000
	Greater Carrizo	570
	Greater Imperial	1,317
	Kramer & Inyokern	375
	Mountain Pass & El Dorado	-
	Northern California	1,702
	Riverside East & Palm Springs	2,459
	Solano	551
	Southern California Desert	-
	Tehachapi	2,500
	Westlands	1,450
	Subtotal	**11,924**
Wind	Central Valley & Los Banos	150
	Greater Carrizo	500
	Greater Imperial	400
	Riverside East & Palm Springs	500
	Solano	600
	Tehachapi	850
	Subtotal	***3,000***
Total California Renewable Potential		**16,732**

3.7 Out-of-State Renewable Potential

In Current Practice 1 and Regional 2, the renewable portfolios to meet California's RPS mandates are constrained to include only out-of-state resources that can be delivered on the existing system without requiring major new transmission; resources that would require major new interregional transmission projects are excluded. In Regional 3, the portfolio considers both projects that can be delivered through existing transmission as well as those that would require major new transmission investment. The transmission costs associated with each of these resources are discussed in Section 3.9.

Table 15. Out-of-state resource potential included in RESOLVE.

Resource		Description	Potential (MW)		
			Current Practice 1	Regional 2	Regional 3
Arizona Solar PV		High quality solar PV resource, available for delivery on existing transmission system	1,500	1,500	1,500
New Mexico Wind	1	Highest quality wind resource, requires new transmission investment	-	-	1,500
	2	Medium quality wind resource, requires new transmission investment	-	-	1,500
	3	Lowest quality wind resource, available for delivery on existing transmission system	1,000	1,000	1,000
Oregon Wind		Low quality wind resource, available for delivery on existing transmission system	2,000	2,000	2,000
Wyoming Wind	1	Highest quality wind resource, requires new transmission investment	-	-	1,500
	2	Medium quality wind resource, requires new transmission investment	-	-	1,500
	3	Lowest quality wind resource, available for delivery on existing transmission system	500	500	500
Total Out-of-State Resources Available			**5,000**	**5,000**	**11,000**

3.8 Renewable Cost & Performance

Renewable resource cost and performance for the resources identified in Sections 3.3 and 3.7 are derived from the CPUC's RPS Calculator (version 6.1), with adjustments made to solar and geothermal costs based on stakeholder feedback as part of the SB 350 study process. The RPS Calculator's assumptions regarding cost and performance for new renewables have been modified—in most cases, reduced—for this study based on stakeholder feedback and a review of current literature, including:

- *2014 Wind Technologies Market Report* (US DOE);[10]
- *Utility Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (LBNL);[11]
- WREZ Generation and Transmission model (version 2.5);[12] and
- Email correspondence with the Geothermal Energy Association.

The cost and performance of all candidate renewables for the portfolios—both in California and in the rest of the WECC—are summarized in Table 16. The federal renewable investment tax credit ("ITC") and production tax credit ("PTC") are both assumed to be reduced by 2030 according to current federal policy. The Federal PTC and ITC phase out by 2019 for wind and by 2021 for solar and geothermal. Solar PV and geothermal remain eligible for a 10% ITC after 2021.

Learning rates are assumed to reduce the capital cost of renewable technologies over time. However, the scheduled roll-offs of the federal PTC and ITC can result in a higher levelized cost of energy ("LCOE") in 2030 compared to today.

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[10] Available at: http://energy.gov/sites/prod/files/2015/08/f25/2014-Wind-Technologies-Market-Report-8.7.pdf
[11] Available at: https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf
[12] Available at: http://www.westgov.org/component/docman/doc_download/1475-wrez-generation-and-transmission-model-

Table 16. Renewable resource cost & performance assumptions in RESOLVE.

Resource	Geography		Capacity Factor (%)	Capital Cost (2015 $/kW)		LCOE (2015 $/MWh)	
				2015	2030	2015	2030
California Geothermal	Imperial		90%	$ 5,142	$ 5,142	$ 76	$ 96
	Northern California		80%	$ 3,510	$ 3,510	$ 59	$ 81
California Solar PV	Central Valley & Los Banos		30%	$ 2,174	$ 1,826	$ 58	$ 76
	Greater Carrizo		33%	$ 2,174	$ 1,826	$ 53	$ 69
	Greater Imperial		31%	$ 2,174	$ 1,826	$ 56	$ 73
	Kramer & Inyokern		34%	$ 2,174	$ 1,826	$ 50	$ 66
	Mountain Pass & El Dorado		34%	$ 2,174	$ 1,826	$ 50	$ 65
	Northern California		29%	$ 2,174	$ 1,826	$ 59	$ 78
	Riverside East & Palm Springs		32%	$ 2,174	$ 1,826	$ 53	$ 70
	Solano		29%	$ 2,174	$ 1,826	$ 59	$ 78
	Southern California Desert		34%	$ 2,174	$ 1,826	$ 51	$ 67
	Tehachapi		33%	$ 2,174	$ 1,826	$ 52	$ 68
	Westlands		31%	$ 2,174	$ 1,826	$ 55	$ 72
OOS Solar PV	Arizona		34%	$ 2,001	$ 1,711	$ 45	$ 56
California Wind	Central Valley & Los Banos		30%	$ 2,069	$ 2,008	$ 51	$ 76
	Greater Carrizo		31%	$ 1,914	$ 1,857	$ 49	$ 74
	Greater Imperial		35%	$ 2,083	$ 2,022	$ 43	$ 68
	Riverside East & Palm Springs		33%	$ 2,047	$ 1,987	$ 57	$ 82
	Solano		27%	$ 1,992	$ 1,933	$ 58	$ 82
	Tehachapi		35%	$ 2,087	$ 2,025	$ 47	$ 72
OOS Wind	New Mexico	1	46%	$ 1,738	$ 1,687	$ 21	$ 46
		2	42%	$ 1,738	$ 1,687	$ 26	$ 51
		3	39%	$ 1,738	$ 1,687	$ 30	$ 55
	Oregon		32%	$ 1,943	$ 1,885	$ 49	$ 74
	Wyoming	1	46%	$ 1,738	$ 1,687	$ 21	$ 46
		2	42%	$ 1,738	$ 1,687	$ 26	$ 51
		3	39%	$ 1,738	$ 1,687	$ 30	$ 55

* OOS = out-of-state, LCOE = levelized cost of energy . Solar capital cost is expressed with respect to AC capacity with assumed inverter loading ratio of 1.3; i.e. the cost per kW-AC is 1.3 times higher than the cost per kW-DC.

3.9 Transmission Availability & Cost

3.9.1 CALIFORNIA RESOURCES

For each resource zone in California, the ability to connect resources to the existing system is limited; assumptions are based on the rules of thumb developed by ISO for its 50 % Renewable Energy Special Study conducted as part of the 2015-2016 Transmission Planning process.[13] To the extent that the available resource potential in a zone exceeds the limits of the existing system, a transmission cost penalty is included for incremental additions beyond these limits; the assumed transmission cost is based on the assumptions of the RPS Calculator. This two-tiered approach for applying transmission costs to new resources is shown illustratively in Figure 4, where 'Available Capacity (a)' represents the limit of a system to accommodate new renewables at no cost; and 'Incremental Cost (b)' reflects the cost of new transmission upgrades once the available capacity has been exhausted. The assumptions for each of these parameters for each resource zone in California are summarized in Table 17.

[13] Available at: https://www.ISO.com/Documents/Draft2015-2016TransmissionPlan.pdf

Figure 4. Illustrative transmission costing for a California resource zone in RESOLVE

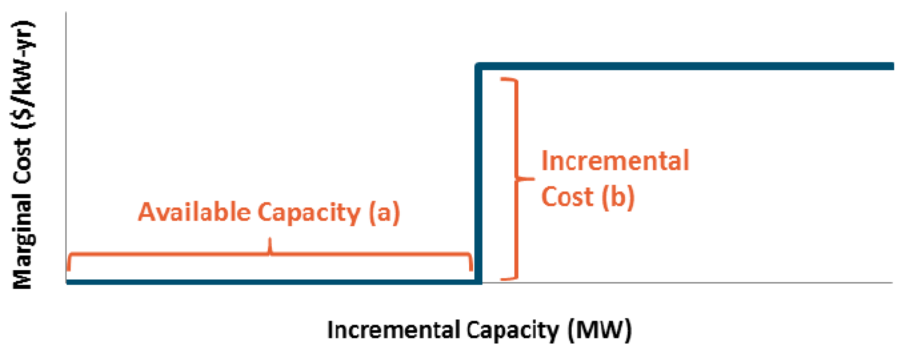

Table 17. Availability of energy only capacity and cost of transmission upgrades in California zones.

Zone	Capacity Available at no cost (MW)	Cost for Incremental Capacity ($/kW-yr.)
Central Valley & Los Banos	2,000	$ 29
Greater Carrizo	1,140	$ 114
Greater Imperial	2,633	$ 68
Kramer & Inyokern	750	$ 52
Mountain Pass & El Dorado	2,982	$ 65
Northern California	3,404	$ 95
Riverside East & Palm Springs	4,917	$ 85
Solano	1,101	$ 13
Southern California Desert	-	$ 64
Tehachapi	5,000	$ 21
Westlands	2,900	$ 58

3.9.2 OUT-OF-STATE RESOURCES

The transmission needs associated with out-of-state resources vary depending both on the resource and the scenario, but generally reflect one of two types of costs:

- Wheeling and pancake losses resulting from the need to purchase firm service on the existing transmission system from one or more neighboring balancing authorities; or
- Costs associated with major new projects to deliver a renewable resource to a sufficiently liquid trading hub.

The application of these costs to out-of-state resources varies by scenario:

- In Current Practice 1, only resources that can be delivered on the existing system are considered; the cost of wheeling through neighboring balancing areas is attributed to these resources. Current Practice 1 does not include resources that would require major new interregional transmission infrastructure to be constructed.
- Regional 2 considers the same set of resources as Current Practice 1; however, the shift towards a regional market results in no direct wheeling costs for the entities within the Regional ISO.
- Regional 3 considers both resources that can be delivered on the existing system as well as those that would require major new transmission. Resources that can be delivered on the existing system incur no transmission costs. Resources that require transmission upgrades are assumed to pay the annual revenue requirement associated those upgrades.

The differential treatment of transmission costs in each scenario—as well as the basis used to estimate each resource's associated transmission costs—are summarized in Table 18.

Table 18. Transmission cost assumptions for out-of-state resources

Resource		Quantity (MW)	Costs ($/kW-year)			Basis for Assumption
			CP 1	Reg. 2	Reg. 3	
Southwest Solar PV		1500	$39	$0	$0	Wheeling & losses on APS system
New Mexico Wind	1	1500	N/A	N/A	$50	Assumed project capital cost ($567 million for 1,500 MW of new transmission) based on RPS Calculator transmission costs, scaled for distance for delivery to Four Corners
	2	1500	N/A	N/A	$129	Sum of public information regarding SunZia costs ($2 billion for 3,000 MW) and assumed upgrade costs from Pinal Central to Palo Verde based on RPS Calculator
	3	1000	$72	$0	$0	Wheeling & losses on PNM & APS systems
Northwest Wind		2000	$34	$0	$0	Wheeling & losses on BPA system (system + southern intertie rates)
Wyoming Wind	1 & 2	3000	N/A	N/A	$88	Costs of Gateway project reported ($252 million per year for 2,875 MW) reported in *Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration* (Technical Appendix)
	3	500	$66	$0	$0	Wheeling & losses on PacifiCorp East & NV Energy systems

3.10 Storage Resources

Energy storage cost and performance inputs are based on a review of the literature and projections from manufacturers and developers, including:

+ *Lazard's Levelized Cost of Storage Analysis – version 1.0 (*Lazard, 2015);[14]
+ *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA* (Sandia National Laboratories, 2013);[15]
+ *Electrical energy storage systems: A comparative life cycle cost analysis* (Zakery and Syri, Renewable and Sustainable Energy Reviews 2015);[16]
+ *Rapidly falling costs of battery packs and electric vehicles* (Nykvist and Nilsson, Nature Climate Change 2015);[17]
+ *2015 Greentechmedia.com coverage on emerging battery manufacturers*
+ *Tesla Powerwall webpage (Last visited March 2016);*[18]
+ *Capital Cost Review of Power Generation Technologies; Recommendations for WECC's 10- and 20-year studies (E3, 2014); only used for pumped hydro*[19]

[14] Available at: https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf
[15] Available at: http://www.sandia.gov/ess/publications/SAND2013-5131.pdf
[16] Available at: http://www.sciencedirect.com/science/article/pii/S1364032114008284
[17] Available at: http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html
[18] Available at: https://www.teslamotors.com/powerwall
[19] Available at: https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

Capital investment and O&M costs are annualized using E3's WECC Pro Forma tool. For lithium ion and flow batteries, a 15% adder is added on top of the capital costs shown in Table 20 to take into account engineering, procurement and construction ("EPC"), and interconnection. E3 modeled replacement of the lithium ion battery pack in year 8 and replacement of the flow battery and lithium ion battery power conversion system in year 10. Replacement costs are assumed to be equal to the capital costs of the replacement item in the year of replacement (not including the 15% adder).

Cost and performance assumptions for energy storage technologies are summarized in the tables below.

Table 19. Energy storage performance and resource potential by technology.

Technology	Charging & Discharging Efficiency	Financing Lifetime (yr)	Replace-ment (yr)	Minimum duration (hrs)	Resource Potential (MW)
Lithium Ion Battery	92%	16	8	0	N/A
Flow Battery	84%	20	N/A	0	N/A
Pumped Hydro	87%	40	N/A	12	4,000

Note: For Lithium Ion Batteries and Flow Batteries we also assume inverter replacement at year 10.

Table 20. Energy storage cost assumptions by technology.

Type	Cost Metric	2015	2030
Lithium Ion Battery	Storage Cost ($/kWh)	$375	$183
	Power Conversion System Cost ($/kW)	$300	$204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	$7.5	$3.7
	Fixed O&M PCS ($/kW-yr)	$6.0	$4.1
Flow Battery	Storage Cost ($/kWh)	$700	$315
	Power Conversion System Cost ($/kW)	$300	$204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	$14.0	$6.3
	Fixed O&M PCS ($/kW-yr)	$6.0	$4.1
Pumped Hydro	Storage Cost ($/kWh)	$117	$117
	Power Conversion System Cost ($/kW)	$1,400	$1,400
	Fixed O&M Battery/Reservoir ($/kWh-yr)	-	-
	Fixed O&M PCS ($/kW-yr)	$15	$15

Table 21. Energy storage cost estimates in 2015 and 2030 for each technology ($/kW-yr and $/KWh-yr).

Technology	2015 Annualized Cost Components ($/kW-yr; $/kWh-yr)	2030 Annualized Cost Components ($/kW-yr; $/kWh-yr)
Lithium Ion Battery	$69; $85	$46; $40
Flow Battery	$58; $118	$39; $53
Pumped Hydro	$146; $12	$146; $12

Note: The first number indicates the annualized cost of the power conversion system ($/kW-yr) of the device and the second number indicates the annualized cost of the energy storage capacity or reservoir size ($/kWh-yr). Both numbers are additive. This annualized cost is the full cost of owning and operating the system, including O&M and replacement costs

3.11 Conservative nature of study assumptions

When considering appropriate assumptions for the base case, E3 has tried as a general to make assumptions that are conservative, i.e., that tend to understate the potential benefits of a regional market. While not every individual assumption is conservative, we believe that the assumptions as a whole result in a conservative estimate of the benefits of a regional market. Most importantly, we have assumed that a number of renewable integration solutions are in place by 2030, despite the fact that each solution is significantly more costly than a regional market (which returns positive net benefits even before renewable integration is considered). Conservative assumptions include:

- The study assumes that time-of-use retail electricity rates are in place that encourage daytime use, shifting 1000 MW of load into daylight hours with overgeneration.

- The study assumes that 5 million electric vehicles are in service by 2030, with near-universal access to workplace charging. A significant proportion of the charging occurs during daylight hours with overgeneration.

- The study assumes that 500 MW of pumped storage are added to the portfolio in all scenarios, despite the fact that this resource is not cost-effective using study assumptions. This significantly reduces the renewable integration burden under Current Practice 1.

- The study assumes that 500 MW of geothermal are added to the portfolio in all scenarios, displacing approximately 1500 MW of wind or solar resources that would otherwise have been needed. This significantly reduces the renewable integration burden under Current Practice 1.

- The study assumes that 5,000 MW of out-of-state renewable resources, delivered over existing transmission, are available to be selected on a least-cost basis. This provides diversity to the portfolio and significantly reduces the renewable integration burden under Current Practice 1.

- The study assumes that a regional market makes available only 6000 MW of out of state resources. In reality, a truly regional market could unlock vast quantities of renewable resource potential from across the interconnection.

- The study assumes that unlimited bulk energy storage is available to be selected on a least-cost basis, with very aggressive cost reduction trajectories.

- The study assumes that renewables are allowed to provide downward operating reserves across all scenarios. This significantly reduces the quantity of thermal generation that runs during overgeneration hours, and therefore the quantity of renewable curtailment that could be avoided with a regional market.

- The study assumes that storage and hydro provide operating reserves and frequency response, significantly reducing the quantity of thermal generation that runs during overgeneration hours and therefore the quantity of renewable curtailment that could be avoided with a regional market.

- The study uses a simplified representation of the thermal portfolio and imports, understating the extent to which thermal generation inflexibility could exacerbate renewable overgeneration.

- The study assumes that energy-only resources are the dominant form of contract in future renewable procurement, eliminating the need for any new transmission in California to meet the 50% RPS under the Current Practice 1 scenario.

- The study does not fully account for improved regional optimization of hydro resources, which could be called upon to perform renewable integration services under a regional market, reducing curtailment and the necessary renewable overbuild in the Regional 2 and Regional 3 scenarios.

4 Renewable Portfolio Results

4.1 Summary of key findings

Regional markets result in significantly lower renewable procurement costs for California across all scenarios and sensitivities.

- Renewable procurement cost savings are **$680 million/year** in 2030 under regional markets with current practices in renewable procurement
- Procurement cost savings are **$799 million/year** in 2030 under regional markets with regional renewable procurement
- Savings range is **$391-$1,341 million/year** in 2030 under regional markets, across all sensitivities. The largest savings occur under the 55% RPS sensitivity, which is roughly consistent with the commitment PG&E made in the recent Diablo Canyon retirement settlement.

Table 22. Summary of 2030 renewable procurement cost savings offered by a regional market.

Renewable portfolio cost savings from regional market ($MM/year)		Regional 2 vs. Current Practice 1	Regional 3 vs. Current Practice 1
Base Case		$680	$799
A.	**High coordination under bilateral markets**	$391	$511
B.	**High energy efficiency**	$576	$692
C.	**High flexible loads**	$495	$616
D.	**Low portfolio diversity**	$895	$1,004
E.	**High rooftop PV**	$838	$944
F.	**High out-of-state resource availability**	$578	$661
G.	**55% RPS**	$1,164	$1,341
H.	**Low cost solar**	$510	$647

4.2 Renewable portfolios

RESOLVE is used to obtain the optimal renewable portfolios for the ISO balancing area in each scenario. For the non-ISO balancing areas ("Munis"), the 2030 renewable portfolios are obtained by hand-selecting resources representative of plausible renewable procurement activities in each scenario, which is informed by historical procurement decisions as well as the optimal portfolios RESOLVE selected for the ISO.

The tables below show the renewable portfolios to go from 33% RPS to 50% RPS in 2030 for the ISO, the Munis, and California statewide.

Table 23. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	5,226	5,429	2,136
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,000	115	-
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**8,726**	**7,829**	**4,536**
Total Out-of-State Resources	**4,500**	**4,115**	**6,000**
Total Renewable Resources	**13,226**	**11,944**	**10,536**
Batteries	472	-	-
Pumped Hydro	500	500	500

Table 24. 2030 ISO cumulative renewable portfolio additions in GWh of 2030 annual generation.

New Resources (GWh)	Current Practice 1	Regional 2	Regional 3
California Solar	14,890	15,555	6,211
California Wind	8,480	5,596	5,596
California Geothermal	3,942	3,942	3,942
Northwest Wind, Existing Transmission	2,803	321	-
Northwest Wind RECs	2,803	2,803	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	1,708	1,708	1,708
Wyoming Wind, New Transmission	-	-	6,044
Southwest Solar, Existing Transmission	-	1,489	1,489
Southwest Solar RECs	2,978	2,978	2,978
New Mexico Wind, Existing Transmission	3,416	3,416	3,416
New Mexico Wind, New Transmission	-	-	6,044
Total CA Resources	**27,312**	**25,093**	**15,749**
Total Out-of-State Resources	**13,708**	**12,715**	**21,679**
Total Renewable Resources	**41,020**	**37,808**	**37,428**
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 25. 2030 ISO out-of-state share in renewable portfolio.

Out of State Resource Accounting	Current Practice 1	Regional 2	Regional 3
Out of State Share in incremental 33-50% Portfolio	33%	34%	58%
Out of State Share in total Portfolio	23%	23%	31%

Table 26. 2030 Munis cumulative renewable portfolio additions in MW of installed capacity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	2,375	2,375	1,304
California Wind	-	-	-
California Geothermal	-	-	-
Northwest Wind, Existing Transmission	447	447	318
Northwest Wind RECs	-	-	-
Utah Wind, Existing Transmission	604	604	420
Wyoming Wind, Existing Transmission	-	-	-
Wyoming Wind, New Transmission	-	-	495
Southwest Solar, Existing Transmission	-	-	-
Southwest Solar RECs	-	-	-
New Mexico Wind, Existing Transmission	-	-	-
New Mexico Wind, New Transmission	-	-	462
Total CA Resources	**2,375**	**2,375**	**1,304**
Total Out-of-State Resources	**1,051**	**1,051**	**1,694**
Total Renewable Resources	**3,426**	**3,426**	**2,998**
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 27. 2030 Munis cumulative renewable portfolio additions in GWh of 2030 annual generation.

New Resources (GWh)	Current Practice 1	Regional 2	Regional 3
California Solar	6,592	6,592	3,616
California Wind	-	-	-
California Geothermal	-	-	-
Northwest Wind, Existing Transmission	1,253	1,253	891
Northwest Wind RECs	-	-	-
Utah Wind, Existing Transmission	1,693	1,693	1,177
Wyoming Wind, Existing Transmission	-	-	-
Wyoming Wind, New Transmission	-	-	1,993
Southwest Solar, Existing Transmission	-	-	-
Southwest Solar RECs	-	-	-
New Mexico Wind, Existing Transmission	-	-	-
New Mexico Wind, New Transmission	-	-	1,861
Total CA Resources	**6,592**	**6,592**	**3,616**
Total Out-of-State Resources	**2,946**	**2,946**	**5,922**
Total Renewable Resources	**9,538**	**9,538**	**9,538**
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 28. 2030 Munis out-of-state share in renewable portfolio.

Out of State Resource Accounting	Current Practice 1	Regional 2	Regional 3
Out of State Share in incremental 33-50% Portfolio	31%	31%	62%
Out of State Share in total Portfolio (estimate)	29%	29%	39%

The 33% Muni portfolio is not explicitly modeled. E3 estimates the 33% portfolio consists of 13,442 GWh in-state renewables and 5,073 GWh out-of-state renewables

Table 29. 2030 Statewide cumulative renewable portfolio additions in MW of installed capacity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	7,601	7,804	3,440
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,447	562	318
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	604	604	420
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,995
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,962
Total CA Resources	11,101	10,204	5,840
Total Out-of-State Resources	5,551	5,166	7,694
Total Renewable Resources	**16,652**	**15,370**	**13,534**
Batteries	472	-	-
Pumped Hydro	500	500	500

Table 30. 2030 Statewide cumulative renewable portfolio additions in GWh of 2030 annual generation.

New Resources (GWh)	Current Practice 1	Regional 2	Regional 3
California Solar	21,482	22,147	9,827
California Wind	8,480	5,596	5,596
California Geothermal	3,942	3,942	3,942
Northwest Wind, Existing Transmission	4,056	1,574	891
Northwest Wind RECs	2,803	2,803	-
Utah Wind, Existing Transmission	1,693	1,693	1,177
Wyoming Wind, Existing Transmission	1,708	1,708	1,708
Wyoming Wind, New Transmission	-	-	8,037
Southwest Solar, Existing Transmission	-	1,489	1,489
Southwest Solar RECs	2,978	2,978	2,978
New Mexico Wind, Existing Transmission	3,416	3,416	3,416
New Mexico Wind, New Transmission	-	-	7,905
Total CA Resources	33,904	31,685	19,365
Total Out-of-State Resources	16,654	15,661	27,601
Total Renewable Resources	**50,558**	**47,346**	**46,966**
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 31. 2030 Statewide out-of-state share in renewable portfolio.

Out of State Resource Accounting	Current Practice 1	Regional 2	Regional 3
Out of State Share in incremental 33-55% Portfolio	33%	33%	59%
Out of State Share in total Portfolio (estimate)	24%	24%	33%

The 33% Muni portfolio is not explicitly modeled. E3 estimates the 33% portfolio consists of 13,442 GWh in-state renewables and 5,073 GWh out-of-state renewables

4.3 Renewable procurement cost results

Total 2030 annual renewable procurement costs for the non-ISO balancing areas, the ISO balancing area, and the total California state are shown below for each of the modeled scenarios.

Table 32. 2030 Annual cost and REC revenue for the non-ISO balancing areas ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$678	$678	$586
Transmission Costs (new construction and wheeling)	$36	$0	$66
Energy Credit for REC Resources*	-	-	-
Net Total Costs	**$714**	**$678**	**$652**
Procurement Savings Relative to Current Practice 1		$36	$62

**Pricing for REC resources is based on the PPA price of a new resource net of its energy value in local markets. Since this energy credit is not captured explicitly in PSO modeling, it is included here as an explicit adjustment. The energy value of all non-REC renewable resources is captured directly through PSO modeling.*

Table 33. 2030 Annual cost and REC revenue for the ISO balancing area ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,619	$2,174	$1,761
Transmission Costs (new construction and wheeling)	$198	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs	**$2,578**	**$1,934**	**$1,840**
Procurement Savings Relative to Current Practice 1		$644	$737

Table 34. 2030 Statewide annual cost and REC revenue ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$3,297	$2,852	$2,347
Transmission Costs (new construction and wheeling)	$234	$0	$273
Energy Credit for REC Resources*	(240)	(240)	(127)
Net Total Costs	**$3,292**	**$2,612**	**$2,492**
Procurement Savings Relative to Current Practice 1		$680	$799

4.3.1 TOTAL RETAIL REVENUE REQUIREMENT CALCULATION

The total retail revenue requirement used for the purpose of the overall rate-impact analysis presented in this SB350 study is based on EIA's 2015 revenue requirement for the state of California.[20] Consistent with RPS calculator results, E3 assumed 82% of the 2015 revenue requirement is fixed and thus, does not change across the scenarios modeled in this study (i.e., only the remaining 18% is a variable cost covered by TEAM variable procurement cost and an RPS-portfolio-related variable capital investment cost). These fixed costs of serving California retail load that do not vary across the modeled scenarios consist of the costs associated with existing transmission, distribution, generation and renewables, DSM programs, and other fees. These fixed retail costs are assumed to increase at a 1% real escalation rate.

Total retail annual revenue requirement associated with serving California ratepayers is then calculated by adding costs from the following simulation results to the fixed retail costs estimates:

[20] Available here: http://www.eia.gov/electricity/data/eia826/xls/sales_revenue.xls

- Annualized renewable procurement costs associated RPS-portfolio-related incremental capital investment (from RESOLVE, includes incremental renewable procurement, storage incremental to the storage mandate, wheeling and losses charges for out-of-state renewables, energy credit for REC resources, and incremental transmission buildout);
- Wholesale power production, purchase and sales costs (from TEAM calculations);
- Annualized generation capacity cost impacts associated with regional load diversity benefit; and
- Changes in Grid Management Charges (GMC) to California loads

4.4 Renewable Curtailment

The table below shows the 2030 renewable curtailment results for the ISO balancing area.

Table 35. 2030 Renewable curtailment in ISO balancing area.

Renewable Energy Curtailment	Current Practice 1	Regional 2	Regional 3
Total Curtailment (GWh)	4,818	1,606	1,226
Curtailment as % of available RPS energy	4.5%	1.6%	1.2%

4.5 Results by CREZ

The tables below show the renewable portfolios and the costs to go from 33% RPS to 50% RPS in 2030 detailed by CREZ, for the non-ISO balancing areas, the ISO balancing area, and California State. The study team made a determination of siting the renewables based on both the capacity required to meet 50% RPS and the environmental impact to the various CREZ.

The non-ISO portfolios are hand-picked to provide a representative indication of the potential effects of a regional market on the portfolios of non-ISO utilities. The resource portfolios were selected to be consistent with the overall resource procurement patterns emerging from the RESOLVE analysis.

For the ISO area, several trends are notable. First, the total quantity of resources procured is reduced moving from Current Practice 1 and Regional 2, and again to Regional 3. This is due to two factors: reduced curtailment, requiring less overbuild of the portfolio (between Current Practice 1 and Regional 2) and access to higher quality resources, allowing more energy to be produced per MW of resource installed (between Regional 2 and Regional 3).

Second, there is some variation among the scenarios in terms of the California solar zones selected. For example, development moves from the Westlands zone in Current Practice 1 to the Riverside East zone in Regional 2. This is due to minor differences in the resource output shape that result in very small differences in resource valuation across scenarios. These differences can make an impact in an optimization model like RESOLVE; however, RESOLVE does not consider issues like environmental impact, permitting, siting, water availability, and others that can have a material impact on the success of real projects. Thus, the specific zones that are selected should be thought of as representative of areas with similar resource quality, rather than a firm indication that development is more likely in one area than another.

Finally, Regional 3 results in significant quantities of additional wind development in Wyoming and New Mexico. This development, which requires new transmission lines to be constructed in other states for the benefit of California consumers, is highly unlikely to occur in the absence of a regional transmission entity. While there are a number of projects in various stages of development aimed at providing access to high quality New Mexico and Wyoming wind, none of these projects have been successful in today's bilateral world. FERC's Order 1000 aims at facilitating these types of inter-regional transmission projects, and the ISO along with other utilities are participating in regional planning exercises examining these questions. However, in the absence of a planning entity with a broad regional scope and, most importantly, the authority to allocate costs of new transmission facilities to customers across a broad region, these projects face very significant hurdles that have, thus far, prevented them from successful development.

Table 36. 2030 Munis cumulative renewable portfolio additions in MW of installed capacity by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	873	873	486
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	578	578	305
Greater_Imperial_Solar	Solar	923	923	512
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	447	447	318
OR_Wind_REC	Wind	-	-	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	495
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	-	-	-
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	462
UT_Wind_ExistingTx	Wind	604	604	420
Grand Total		**3,426**	**3,426**	**2,998**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-

Table 37. 2030 Munis cumulative renewable portfolio additions in GWh of 2030 annual generation by CREZ.

Resource (CREZ)	Technology	Current Prac	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	2,401	2,401	1,336
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	1,672	1,672	883
Greater_Imperial_Solar	Solar	2,519	2,519	1,397
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	1,253	1,253	891
OR_Wind_REC	Wind	-	-	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	1,993
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	-	-	-
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	1,861
UT_Wind_ExistingTx	Wind	1,693	1,693	1,177
Grand Total		**9,538**	**9,538**	**9,538**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-

Table 38. Munis annualized incremental investment costs in 2030 by CREZ (excl. transmission; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	$ 167	$ 167	$ 93
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	$ 111	$ 111	$ 58
Greater_Imperial_Solar	Solar	$ 179	$ 179	$ 99
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 221	$ 221	$ 155
OR_Wind_REC	Wind	-	-	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	$ 93
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	-	-	-
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	$ 87
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 678**	**$ 678**	**$ 586**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ 678**	**$ 678**	**$ 586**

Table 39. Munis annualized incremental transmission costs in 2030 by CREZ (new construction and wheeling; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 36	-	-
OR_Wind_REC	Wind	-	-	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	$ 43
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	-	-	-
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	$ 23
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 36**	**-**	**$ 66**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ 36**	**-**	**$ 66**

Table 40. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	500	500	500
Greater_Carrizo_Solar	Solar	570	570	-
Kramer_Inyokern_Solar	Solar	375	375	375
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	331	1,984	-
Tehachapi_Solar	Solar	2,500	2,500	1,761
Westlands_Solar	Solar	1,450	-	-
Central_Valley_North_Los_Banos_Wind	Wind	150	150	150
Greater_Carrizo_Wind	Wind	500	500	500
Greater_Imperial_Wind	Wind	400	400	400
Riverside_East_Palm_Springs_Wind	Wind	500	-	-
Solano_Wind	Wind	600	-	-
Tehachapi_Wind	Wind	850	850	850
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	1,000	115	-
OR_Wind_REC	Wind	1,000	1,000	-
WY_Wind_ExistingTx	Wind	500	500	500
WY_Wind_NewTx_1	Wind	-	-	1,500
AZ_Solar_ExistingTx	Solar	-	500	500
AZ_Solar_REC	Solar	1,000	1,000	1,000
NM_Wind_ExistingTx	Wind	1,000	1,000	1,000
NM_Wind_NewTx_1	Wind	-	-	1,500
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total		**13,226**	**11,944**	**10,536**
Storage				
Li-ion Battery	Storage	472	-	-
Pumped Storage	Storage	500	500	500

Table 41. 2030 ISO cumulative renewable portfolio additions in GWh of 2030 annual generation by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	3,942	3,942	3,942
Greater_Carrizo_Solar	Solar	1,624	1,624	-
Kramer_Inyokern_Solar	Solar	1,115	1,115	1,115
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	930	5,582	-
Tehachapi_Solar	Solar	7,234	7,234	5,096
Westlands_Solar	Solar	3,987	-	-
Central_Valley_North_Los_Banos_Wind	Wind	394	394	394
Greater_Carrizo_Wind	Wind	1,358	1,358	1,358
Greater_Imperial_Wind	Wind	1,244	1,244	1,244
Riverside_East_Palm_Springs_Wind	Wind	1,448	-	-
Solano_Wind	Wind	1,436	-	-
Tehachapi_Wind	Wind	2,601	2,601	2,601
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	2,803	321	-
OR_Wind_REC	Wind	2,803	2,803	-
WY_Wind_ExistingTx	Wind	1,708	1,708	1,708
WY_Wind_NewTx_1	Wind		-	6,044
AZ_Solar_ExistingTx	Solar	-	1,489	1,489
AZ_Solar_REC	Solar	2,978	2,978	2,978
NM_Wind_ExistingTx	Wind	3,416	3,416	3,416
NM_Wind_NewTx_1	Wind		-	6,044
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total		**41,021**	**37,809**	**37,429**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-

Table 42. ISO annualized incremental investment costs in 2030 by CREZ (excl. transmission; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	$ 379	$ 379	$ 379
Greater_Carrizo_Solar	Solar	$ 90	$ 90	-
Kramer_Inyokern_Solar	Solar	$ 59	$ 59	$ 59
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	$ 52	$ 313	-
Tehachapi_Solar	Solar	$ 394	$ 394	$ 278
Westlands_Solar	Solar	$ 284	-	-
Central_Valley_North_Los_Banos_Wind	Wind	$ 21	$ 21	$ 21
Greater_Carrizo_Wind	Wind	$ 68	$ 68	$ 68
Greater_Imperial_Wind	Wind	$ 55	$ 55	$ 55
Riverside_East_Palm_Springs_Wind	Wind	$ 84	-	-
Solano_Wind	Wind	$ 85	-	-
Tehachapi_Wind	Wind	$ 126	$ 126	$ 126
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 202	$ 16	-
OR_Wind_REC	Wind	$ 209	$ 142	-
WY_Wind_ExistingTx	Wind	$ 52	$ 52	$ 52
WY_Wind_NewTx_1	Wind	-	-	$ 132
AZ_Solar_ExistingTx	Solar	-	$ 70	$ 70
AZ_Solar_REC	Solar	$ 167	$ 141	$ 141
NM_Wind_ExistingTx	Wind	$ 104	$ 104	$ 104
NM_Wind_NewTx_1	Wind	-	-	$ 132
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 2,431**	**$ 2,028**	**$ 1,615**
Storage				
Li-ion Battery	Storage	$ 43	-	-
Pumped Storage	Storage	$ 146	$ 146	$ 146
Grand Total with Storage		**$ 2,620**	**$ 2,174**	**$ 1,761**

Table 43. ISO annualized incremental transmission costs in 2030 by CREZ (new construction and wheeling; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state		-	-	-
OR_Wind_ExistingTx	Wind	$ 34	-	-
OR_Wind_REC	Wind	$ 20	-	-
WY_Wind_ExistingTx	Wind	$ 33	-	-
WY_Wind_NewTx_1	Wind	-	-	$ 131
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	$ 39	-	-
NM_Wind_ExistingTx	Wind	$ 72	-	-
NM_Wind_NewTx_1	Wind	-	-	$ 75
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 198**	**-**	**$ 207**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ 198**	**-**	**$ 207**

Table 44. ISO annualized incremental energy credit for REC resources in 2030 by CREZ (REC resources only; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	-	-	-
OR_Wind_REC	Wind	$ (113)	$ (113)	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	-
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	$ (127)	$ (127)	$ (127)
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	-
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ (240)**	**$ (240)**	**$ (127)**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ (240)**	**$ (240)**	**$ (127)**

Table 45. 2030 Statewide cumulative renewable portfolio additions in MW of installed capacity by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	500	500	500
Greater_Carrizo_Solar	Solar	570	570	-
Kramer_Inyokern_Solar	Solar	375	375	375
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	331	1,984	-
Tehachapi_Solar	Solar	2,500	2,500	1,761
Westlands_Solar	Solar	2,323	873	486
Central_Valley_North_Los_Banos_Wind	Wind	150	150	150
Greater_Carrizo_Wind	Wind	500	500	500
Greater_Imperial_Wind	Wind	400	400	400
Riverside_East_Palm_Springs_Wind	Wind	500	-	-
Solano_Wind	Wind	600	-	-
Tehachapi_Wind	Wind	850	850	850
Owens_Valley_Solar	Solar	578	578	305
Greater_Imperial_Solar	Solar	923	923	512
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	1,447	562	318
OR_Wind_REC	Wind	1,000	1,000	-
WY_Wind_ExistingTx	Wind	500	500	500
WY_Wind_NewTx_1	Wind	-	-	1,995
AZ_Solar_ExistingTx	Solar	-	502	502
AZ_Solar_REC	Solar	1,000	1,000	1,000
NM_Wind_ExistingTx	Wind	1,000	1,000	1,000
NM_Wind_NewTx_1	Wind	-	-	1,962
UT_Wind_ExistingTx	Wind	604	604	420
Grand Total		**16,652**	**15,371**	**13,536**
Storage				
Li-ion Battery	Storage	472	-	-
Pumped Storage	Storage	500	500	500

Table 46. 2030 Statewide cumulative renewable portfolio additions in GWh of 2030 renewable generation by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	3,942	3,942	3,942
Greater_Carrizo_Solar	Solar	1,624	1,624	-
Kramer_Inyokern_Solar	Solar	1,115	1,115	1,115
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	930	5,582	-
Tehachapi_Solar	Solar	7,234	7,234	5,096
Westlands_Solar	Solar	6,388	2,401	1,336
Central_Valley_North_Los_Banos_Wind	Wind	394	394	394
Greater_Carrizo_Wind	Wind	1,358	1,358	1,358
Greater_Imperial_Wind	Wind	1,244	1,244	1,244
Riverside_East_Palm_Springs_Wind	Wind	1,448	-	-
Solano_Wind	Wind	1,436	-	-
Tehachapi_Wind	Wind	2,601	2,601	2,601
Owens_Valley_Solar	Solar	1,672	1,672	883
Greater_Imperial_Solar	Solar	2,519	2,519	1,397
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	4,056	1,574	891
OR_Wind_REC	Wind	2,803	2,803	-
WY_Wind_ExistingTx	Wind	1,708	1,708	1,708
WY_Wind_NewTx_1	Wind	-	-	8,037
AZ_Solar_ExistingTx	Solar	-	1,489	1,489
AZ_Solar_REC	Solar	2,978	2,978	2,978
NM_Wind_ExistingTx	Wind	3,416	3,416	3,416
NM_Wind_NewTx_1	wind	-	-	7,905
UT_Wind_ExistingTx	Wind	1,693	1,693	1,177
Grand Total		**50,559**	**47,347**	**46,967**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-

Table 47. Statewide annualized incremental investment costs in 2030 by CREZ (excl. transmission; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	$ 379	$ 379	$ 379
Greater_Carrizo_Solar	Solar	$ 90	$ 90	-
Kramer_Inyokern_Solar	Solar	$ 59	$ 59	$ 59
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	$ 52	$ 313	-
Tehachapi_Solar	Solar	$ 394	$ 394	$ 278
Westlands_Solar	Solar	$ 451	$ 167	$ 93
Central_Valley_North_Los_Banos_Wind	Wind	$ 21	$ 21	$ 21
Greater_Carrizo_Wind	Wind	$ 68	$ 68	$ 68
Greater_Imperial_Wind	Wind	$ 55	$ 55	$ 55
Riverside_East_Palm_Springs_Wind	Wind	$ 84	-	-
Solano_Wind	Wind	$ 85	-	-
Tehachapi_Wind	Wind	$ 126	$ 126	$ 126
Owens_Valley_Solar	Solar	$ 111	$ 111	$ 58
Greater_Imperial_Solar	Solar	$ 179	$ 179	$ 99
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 423	$ 237	$ 155
OR_Wind_REC	Wind	$ 209	$ 142	-
WY_Wind_ExistingTx	Wind	$ 52	$ 52	$ 52
WY_Wind_NewTx_1	Wind	-	-	$ 225
AZ_Solar_ExistingTx	Solar	-	$ 70	$ 70
AZ_Solar_REC	Solar	$ 167	$ 141	$ 141
NM_Wind_ExistingTx	Wind	$ 104	$ 104	$ 104
NM_Wind_NewTx_1	Wind	-	-	$ 219
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 3,108**	**$ 2,706**	**$ 2,201**
Storage				
Li-ion Battery	Storage	$ 43	-	-
Pumped Storage	Storage	$ 146	$ 146	$ 146
Grand Total with Storage		**$ 3,297**	**$ 2,852**	**$ 2,347**

Table 48. Statewide annualized incremental transmission costs in 2030 by CREZ (new construction and wheeling; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 71	-	-
OR_Wind_REC	Wind	$ 20	-	-
WY_Wind_ExistingTx	Wind	$ 33	-	-
WY_Wind_NewTx_1	Wind	-	-	$ 175
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	$ 39	-	-
NM_Wind_ExistingTx	Wind	$ 72	-	-
NM_Wind_NewTx_1	Wind	-	-	$ 98
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 234**	**-**	**$ 273**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ 234**	**-**	**$ 273**

Table 49. Statewide annualized incremental energy credit for REC resources in 2030 by CREZ (REC resources only; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	-	-	-
OR_Wind_REC	Wind	$ (113)	$ (113)	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	-
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	$ (127)	$ (127)	$ (127)
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	-
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ (240)**	**$ (240)**	**$ (127)**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ (240)**	**$ (240)**	**$ (127)**

4.6 Sensitivity analysis results

The robustness of the base case results is tested with a large set of sensitivity cases. Non-ISO Muni results are held constant across all the sensitivities and can be found in section 3.2 and 3.3. Only the ISO inputs and results vary in these sensitivity analyses.

4.6.1 SUMMARY OF SENSITIVITY RESULTS

An overview of the renewable procurement cost results for California state, which includes the Muni results that do not vary by sensitivity, is shown in the tables below.

The sensitivity results show the savings are relatively robust, with savings ranging from $391-1,341 million/year across all sensitivities. Sensitivities that increase the renewable integration challenges such as low portfolio diversity, higher RPS and high rooftop PV show an increase in savings from regional coordination, while sensitivities that ease integration challenges and/or lower the cost of other resources such as high flexible loads and low solar costs decrease the savings. The highest procurement cost savings occur in the 55% RPS sensitivity, which interestingly might become the de facto base case after PG&E's recent decision to close Diablo canyon in 2025 and replace its output with renewables.

Table 50. Overview of 2030 procurement cost savings for California State across all sensitivities.

Renewable Portfolio cost savings from regional market implementation ($MM)	Regional 2 vs. Current Practice 1	Regional 3 vs. Current Practice 1
Base Case	$680	$799
A. High coordination under bilateral markets	$391	$511
B. High energy efficiency	$576	$692
C. High flexible loads	$495	$616
D. Low portfolio diversity	$895	$1,004
E. High rooftop PV	$838	$944
F. High out-of-state resource availability	$578	$661
G. Low cost solar	$510	$647
H. 55% RPS	$1,164	$1,341

Table 51. Overview of 2030 curtailment results for the ISO balancing area across all sensitivities (% of annual RPS generation curtailed).

Renewable Energy Curtailment	Current Practice 1	Regional 2	Regional 3
Base Case	4.5%	1.6%	1.2%
A. High coordination under bilateral markets	2.0%	1.6%	1.2%
B. High energy efficiency	4.8%	1.7%	1.2%
C. High Out of State Availability	3.6%	1.3%	1.1%
D. High flexible loads	4.3%	1.9%	1.7%
E. Low portfolio diversity	5.9%	1.5%	1.2%
F. High rooftop PV	6.8%	2.0%	1.5%
G. Low solar cost	5.7%	1.8%	1.2%
H. High RPS (55%)	7.1%	1.8%	1.3%

In the sections that follow, the sensitivities are explained shortly and detailed portfolio and procurement cost results are shown.

4.6.2 HIGH COORDINATION UNDER BILATERAL MARKETS

In this "current practices" sensitivity, the ISO simultaneous export limit is increased from 2,000 MW to 8,000 MW in Current Practice 1, while the procurement and operations are kept at current practices (ISO-wide). This reflects a scenario where there is no regional coordination, but high coordination under the current bilateral markets allows for higher exports. This sensitivity is also referred to as "Sensitivity 1B" in some of the public material, including the stakeholder presentation slides from May 24 - 25. The results for Sensitivity 1B in these slides for are the same as the results for Current Practice 1 in the table below.

The increased export limits in Current Practice 1 create more room for in-state solar as well as solar in the Southwest at the expense of Northwest wind, which has less diversification benefits in this less-constrained scenario. Curtailment and total costs in Current Practice 1 go down, resulting in lower benefits from regional coordination in Regional 2 and 3 (compared to the Current Practice 1 base case).

Table 52. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high coordination under bilateral markets" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	5,904	5,429	2,136
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	-	115	-
Northwest Wind RECs	-	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	272	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**9,404**	**7,829**	**4,536**
Total Out-of-State Resources	**2,772**	**4,115**	**6,000**
Total Renewable Resources	**12,176**	**11,944**	**10,536**
Batteries	-	-	-
Pumped Hydro	500	500	500

Table 53. 2030 Annual incremental cost and REC revenue for the ISO area for the "high coordination under bilateral markets" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,262	$2,174	$1,761
Transmission Costs (new construction and wheeling)	$155	$0	$207
Energy Credit for REC Resources*	-$127	-$240	-$127
Net Total Costs - CAISO	**$2,289**	**$1,934**	**$1,840**
Net Total Costs -Statewide (incl. Munis)	**$3,003**	**$2,612**	**$2,492**
Statewide Procurement Savings Relative to Current Practice 1		$391	$511

4.6.3 HIGH ENERGY EFFICIENCY

In this sensitivity, the additional achievable energy efficiency (AAEE) is doubled by 2030, lowering retail sales and thus lowering the amount of renewables required to meet the RPS goal. The reduction in load lowers the amount of renewable generation that can benefit from regionalization and thus lowers total benefits.

Table 54. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high energy efficiency" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	2,875	3,580	-
California Wind	3,000	1,900	1,480
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	697	-	-
Northwest Wind RECs	1,000	364	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**6,375**	**5,980**	**1,980**
Total Out-of-State Resources	**4,197**	**3,364**	**6,000**
Total Renewable Resources	**10,572**	**9,344**	**7,980**
Batteries	388	-	-
Pumped Hydro	500	500	500

Table 55. 2030 Annual incremental cost and REC revenue for the ISO area for the "high energy efficiency" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,128	$1,776	$1,367
Transmission Costs (new construction and wheeling)	$188	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,076**	**$1,536**	**$1,446**
Net Total Costs -Statewide (incl. Munis)	**$2,790**	**$2,214**	**$2,098**
Statewide Procurement Savings Relative to Current Practice 1		$576	$692

4.6.4 HIGH FLEXIBLE LOADS

In this sensitivity, 3,000 MW of 4-hour batteries are added in all scenarios. Solar becomes more economic due to the additional flexibility in the system and the need for battery storage is reduced. As a result, benefits from regional markets go down.

Table 56. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high flexible" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	6,126	6,218	2,326
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	-	-	-
Northwest Wind RECs	1,000	455	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**9,626**	**8,618**	**4,726**
Total Out-of-State Resources	**3,500**	**3,455**	**6,000**
Total Renewable Resources	**13,126**	**12,073**	**10,726**
Batteries	87	-	-
Pumped Hydro	500	500	500

Table 57. 2030 Annual incremental cost and REC revenue for the ISO area for the "high flexible loads" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,500	$2,205	$1,790
Transmission Costs (new construction and wheeling)	$164	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,424**	**$1,965**	**$1,870**
Net Total Costs -Statewide (incl. Munis)	**$3,138**	**$2,643**	**$2,522**
Statewide Procurement Savings Relative to Current Practice 1		$495	$616

4.6.5 LOW PORTFOLIO DIVERSITY

In this sensitivity, pumped hydro and geothermal are taken out of the portfolios and total California wind is restricted to 2,000 MW in all scenarios. As a result, the portfolios are much more solar-intensive, which creates more value for diversification of load and resources through regional markets. The benefits therefore go up significantly.

Table 58. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "low portfolio diversity" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	7,549	5,806	3,905
California Wind	2,000	2,000	1,500
California Geothermal	-	-	-
Northwest Wind, Existing Transmission	1,000	1,000	-
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	500	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**9,549**	**7,806**	**5,405**
Total Out-of-State Resources	**5,000**	**5,000**	**6,000**
Total Renewable Resources	**14,549**	**12,806**	**11,405**
Batteries	1,070	-	-
Pumped Hydro	-	-	-

Table 59. 2030 Annual incremental cost and REC revenue for the ISO area for the "low portfolio diversity" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,504	$1,863	$1,460
Transmission Costs (new construction and wheeling)	$218	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,482**	**$1,623**	**$1,540**
Net Total Costs -Statewide (incl. Munis)	**$3,196**	**$2,301**	**$2,192**
Statewide Procurement Savings Relative to Current Practice 1		$895	$1,004

4.6.6 HIGH ROOFTOP PV

In this sensitivity, the total installed capacity of rooftop PV in the ISO balancing area is increased from 16 GW to 21 GW by 2030. As a result, the total renewable generation, when also including rooftop PV, is much more solar-intensive, which creates more value for diversification of load and resources through regional markets. In Current Practice 1, additional battery storage is selected to integrate the additional rooftop PV. The overall effect is that the benefits of regional markets go up.

Table 60. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high rooftop PV" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	4,771	3,403	992
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,000	1,000	-
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**8,271**	**5,803**	**3,392**
Total Out-of-State Resources	**4,500**	**5,000**	**6,000**
Total Renewable Resources	**12,771**	**10,803**	**9,392**
Batteries	1,047	-	-
Pumped Hydro	500	500	500

Table 61. 2030 Annual incremental cost and REC revenue for the ISO area for the "high rooftop PV" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,584	$1,980	$1,580
Transmission Costs (new construction and wheeling)	$198	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,542**	**$1,740**	**$1,660**
Net Total Costs -Statewide (incl. Munis)	**$3,256**	**$2,418**	**$2,312**
Statewide Procurement Savings Relative to Current Practice 1		$838	$944

4.6.7 HIGH OUT OF STATE AVAILABILITY

In this sensitivity, Southwest solar RECs and Northwest wind RECs renewable potential is increased so that they account for up to half of the 50% RPS goal (ISO only), which equals to a renewable potential of 4,526 MW of Northwest wind RECs and 4,279 MW of Southwest solar RECs. The model picks all the available SW solar RECs and no NW wind RECS, and less battery storage is required because the RECs don't need to be balanced in-state. The benefits are lower because lower cost solar RECs displace marginal California solar and out-of-state wind in Current Practice 1.

Table 62. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high out of state availability" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	3,349	2,962	-
California Wind	3,000	1,900	1,750
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	-	-	-
Northwest Wind RECs	-	-	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	4,279	4,279	3,188
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**6,849**	**5,362**	**2,250**
Total Out-of-State Resources	**5,779**	**6,279**	**8,188**
Total Renewable Resources	**12,628**	**11,641**	**10,438**
Batteries	98	-	-
Pumped Hydro	500	500	500

Table 63. 2030 Annual incremental cost and REC revenue for the ISO area for the "high out of state availability" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,359	$2,088	$1,711
Transmission Costs (new construction and wheeling)	$271	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,390**	**$1,848**	**$1,790**
Net Total Costs -Statewide (incl. Munis)	**$3,104**	**$2,526**	**$2,443**
Statewide Procurement Savings Relative to Current Practice 1		$578	$661

4.6.8 LOW SOLAR COST

In this sensitivity, solar costs are reduced to $1/W-DC by 2025. As a result, solar procurement in California goes up significantly, while NW wind procurement goes down. NM wind and WY wind are still selected in Regional 3. The benefits of regional markets go down because the lower cost California solar displaces out-of-state wind in Current Practice 1. There are still significant curtailment reduction benefits in Regional 3.

Table 64. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "low solar cost" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	7,354	6,641	2,752
California Wind	3,000	1,900	1,250
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	-	-	-
Northwest Wind RECs	344	-	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**10,854**	**9,041**	**4,502**
Total Out-of-State Resources	**2,844**	**3,000**	**6,000**
Total Renewable Resources	**13,698**	**12,041**	**10,502**
Batteries	627	-	-
Pumped Hydro	500	500	500

Table 65. 2030 Annual incremental cost and REC revenue for the ISO area for the "low solar cost" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,512	$2,189	$1,759
Transmission Costs (new construction and wheeling)	$151	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,423**	**$1,949**	**$1,838**
Net Total Costs -Statewide (incl. Munis)	**$3,137**	**$2,627**	**$2,490**
Statewide Procurement Savings Relative to Current Practice 1		$510	$647

4.6.9 HIGH RPS (55%)

This sensitivity models a 55% RPS goal. To meet this higher RPS goal, the model shows a significant increase in California solar procurement, as well as additional WY wind procurement in Regional 3. Benefits from regional markets are significantly higher because it is much more costly to meet the higher RPS in Current Practice 1.

Table 66. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high RPS (50%)" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	9,840	7,327	4,313
California Wind	3,000	3,000	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,000	1,000	-
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	2,628
Southwest Solar, Existing Transmission	500	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**13,340**	**10,827**	**6,713**
Total Out-of-State Resources	**5,000**	**5,000**	**7,128**
Total Renewable Resources	**18,340**	**15,827**	**13,841**
Batteries	1,309	-	-
Pumped Hydro	500	500	500

Table 67. 2030 Annual incremental cost and REC revenue for the ISO area for the "High RPS (55%)" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$3,693	$2,783	$2,214
Transmission Costs (new construction and wheeling)	$218	$0	$305
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$3,671**	**$2,543**	**$2,392**
Net Total Costs -Statewide (incl. Munis)	**$4,385**	**$3,221**	**$3,044**
Statewide Procurement Savings Relative to Current Practice 1		$1,164	$1,341

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