APPENDIX 1:

CalWEA's Testimony in Net Energy Metering (NEM) Proceeding (R.20-08-020)

Rulemaking No.:	20-08-020
Exhibit No.:	CWA-01
Witness:	Dariush Shirmohammadi
Date served:	July 16, 2021

PREPARED REBUTTAL TESTIMONY OF DARIUSH SHIRMOHAMMADI

ON BEHALF OF THE CALIFORNIA WIND ENERGY ASSOCIATION

California Wind Energy Association
1700 Shattuck Ave., #17
Berkeley, California 94709
Telephone: (510) 845-5077

July 16, 2021

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, affiliation and business address.

A. My name is Dariush Shirmohammadi. I am the Executive Vice President and Chief Engineer at the consulting firm GridBright, Inc. I serve as Technical Director for the California Wind Energy Association (CalWEA) on whose behalf I am submitting this testimony. My business address is 160 Alamo Plaza #830, Alamo CA 94507.

Q. Please state your qualifications.

A. I have a PhD in Electric Power Engineering from the University of Toronto. In addition, I am a Licensed Professional Engineer and a Life Fellow of the Institute of Electrical and Electronic Engineers (IEEE). I have worked in the electric power industry for over 45 years (since 1975), including tenures as a transmission planning, design and operations engineer at Hydro Quebec, Ontario Hydro, Pacific Gas and Electric Company (PG&E), and the California Independent System Operator (CAISO). I have continued my work on transmission planning, design and operation, particularly as relates to renewable resources interconnection and integration, since 2007 in my current consulting responsibilities. I have also worked in distribution grid planning and optimization while at PG&E and in distribution grid planning, design and operation in my current consulting work. My current work responsibilities primarily focus on interconnection and integration of renewable generation resources, as well as planning for increased penetrations of renewable energy on electrical grids within North America and in California, in particular.

Q. What other relevant experience do you have to these proceedings?

A. As the Director of the CAISO's Regional Transmission South division, part of my responsibility involved day to day operations as well as long-term planning for the CAISO-controlled grid, which included a host of renewable generation resources. After leaving the CAISO in 2007, I started my consulting practice whereby I have continuously provided renewable integration and planning consulting services to CalWEA and many renewable resource developers across North America. I have been a member of the leadership team for the North American Electric Reliability Corporation's ("NERC") Integration of Variable Generation Task Force (IVGTF) and served as one of a handful of non-utility members in the NERC's Essential Reliability Services Task Force (ESRTF). All these major industry initiatives were set up to deal with reliable interconnection and operation of large penetration of renewables in North America's Electric Power Grid. Finally, as part of my responsibilities at the CAISO as well as various consulting responsibilities, I have extensively worked with and applied long-term production simulation tools for studying the economic and reliability aspects of the electric power system particularly for California and the Western Electricity Reliability Council (WECC).

Q. What has been your involvement with resource planning models?

A. As CalWEA's Technical Director, I have regularly reviewed the RESOLVE and SERVM modeling that has been conducted in the Commission's Integrated Resource Planning proceeding and have engaged in related technical workshops and discussions.

II. REBUTTAL TESTIMONY

Q. Which of the issues in the November 19, 2020, Scoping Memo for this proceeding does your rebuttal testimony address?

A. My testimony addresses Issue #3 regarding methods used to analyze parties' proposals for a NEM successor tariff.

Q. What is your rebuttal testimony focused on?

A. I use the "2021 SB 100 Joint Agency Report" (March 2021), the "Input & Assumptions - CEC SB 100 Joint Agency Report" (June 2020), and the SB 100 RESOLVE computer model that supported the SB 100 report, to respond to comments made by certain parties in their opening testimony. The SB 100 report was produced jointly by the Commission, the California Energy Commission, and the California Air Resources Board. The report is the state's initial assessment of the additional energy resources needed to achieve 100 percent zero-carbon electricity by 2045, along with the associated costs. The assessment is supported by RESOLVE modeling analysis. Portions of the SB 100 report were included as Attachment 9 to the opening testimony of the California Solar and Storage Association (CALSSA).[1]

A. Which of the guiding principles approved in Decision 21-02-007 earlier in this proceeding does your testimony inform?

Q. My testimony primarily informs the following principles as numbered and stated in Ordering Paragraph 1 of Decision 21-02-007:

(b) A successor to the net energy metering tariff should ensure equity among customers;

(e) A successor to the net energy metering tariff should be coordinated with the Commission and California's energy policies, including but not limited to, Senate Bill 100 (2018, DeLeon), the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18; and

(g) A successor to the net energy metering tariff should maximize the value of customer-sited renewable generation to all customers and to the electrical system.

A. <u>Treatment of Transmission Costs in the SB 100 Report</u>

Q. The Prepared Direct Testimony of Brad Heavner and Joshua Plaisted on behalf of CALSSA states, on page 4, lines 17-19, that the SB 100 report "did not begin to address

[1] The SB 100 report and modeling files are available at https://www.energy.ca.gov/sb100#anchor_report and the Inputs and Assumptions report is available at https://efiling.energy.ca.gov/getdocument.aspx?tn=234532.

the question of transmission capacity" associated with the various SB 100 scenarios. On page 88, lines 6-7, CALSSA states that "[i]ncreased transmission needs were not studied in SB 100 modeling." Is that your understanding of the SB 100 report?

A. No. On page 66 of the SB 100 report, which is included in Attachment 9 to CALSSA's testimony, the report states that "transmission resources" are included in the description of supply-side candidate resources in the model optimization. On page 67, the report refers to more information on resource assumptions contained in the "Inputs and Assumptions" document, and a link to that document is provided.

Q. What does the Inputs and Assumptions document say about transmission costs?

A. Sections 4.2.7 and 4.2.8 of that document describes how transmission cost and availability are factored into the model's optimization. To summarize, the model includes transmission upgrade costs associated with adding increasing amounts of renewable energy in each renewable energy zone based on a 2019 whitepaper produced by the CAISO. Table 36 of the Inputs and Assumptions document shows the transmission availability and cost of upgrades, in \$/kW-year, for each transmission zone or subzone within CAISO. I will include sections 4.2.7 and 4.2.8 as Attachment 1 to my testimony.

Q. Based on your considerable experience as a transmission planner, do you consider these cost estimates to be a reasonable representation of transmission costs associated with development in each of these zones?

A. Yes, for a study of this general nature, I believe that the transmission cost estimates are a reasonable, high-level approximation of transmission costs associated with renewable energy development in each of the zones.

Q. Would these costs need to be further studied in the CAISO's transmission planning process, and could that lead to a different assessment of costs?

A. Yes, of course. And that conclusion would apply to all other resources studied as part of the study. The costs could be higher or lower than estimated in this report. For example, changes to the CAISO's method of assessing the deliverability of renewable resources, which I believe to be overly conservative, could dramatically lower transmission requirements to deliver renewable energy from many renewable energy zones. CalWEA has for years raised the need for deliverability reform most recently in the Commission's Resource Adequacy Track 3.B.2 structural reform proceeding.

B. Cost-Effectiveness of Customer-Side Solar in Achieving SB 100 Goals

Q. The testimony of Tyson Siegele for Protect Our Communities Foundation, at lines 1-5 on page 6, cites the SB 100 report in stating that "California is currently projecting that it will construct 16,900 MW of new utility-scale solar by 2030. New transmission will be built to support this utility-scale solar expansion." (Footnotes omitted.) Mr. Siegele goes on to state that "California would achieve its GHG reduction targets more cost-effectively by accelerating NEM solar under the current NEM structure and de-emphasizing remote utility-scale solar dependent on new transmission construction." Does the SB 100 report or its model support the contention that customer-side solar would be a more cost-effective means of achieving California's GHG targets than utility-scale solar with new transmission, or other type of utility-scale renewable energy?

A. No. With my colleagues at GridBright, I reviewed the March 2021 SB 100 Joint Agency Report and the SB 100 RESOLVE model that was used to support the report. The SB 100 report centers around a "Core Scenario" that includes only commercialized technologies with publicly available cost and performance data. I observed that, between the years 2022 and 2045, nearly 31.4 GW of additional customer-side solar capacity was included in the 2045 Core Scenario. However, this customer-side capacity addition was a <u>fixed input</u> into the SB 100 RESOLVE model, not the output or a result of an optimum RESOLVE model run. The model includes a variety of "candidate resources" that compete against each other based on their direct and indirect costs (which include transmission-related costs) and performance characteristics to satisfy the zero-carbon energy and reliability resources necessary to achieve SB 100 goals. Customer-side solar was simply not evaluated as a candidate resource in this study based on its cost or performance characteristics. The 31.4 GW of added customer-side solar was simply "hard-wired" into the Core Scenario.

Q. Did you conduct any analysis to determine whether this 31.4 GW capacity addition is a cost-effective means of achieving the SB 100 goal?

A. Yes. With assistance from a colleague at GridBright, we conducted a modeling run to evaluate the Total Resource Cost (TRC) when the level of customer-side solar additions between the years 2022 and 2045 was reduced. We evaluated a 50 percent reduction in the growth rate of the level of customer-side solar embedded in the Core Scenario modeling assumption. Specifically, we reduced the level of added customer-side solar capacity between the years 2022 and 2045 to around 15.7 GW, or nearly 654 MW per year, which is more than three times higher than the 200-MW annual growth level anticipated from the Energy Commission's Title 24 rooftop-solar requirement on new residential homes, based on a September 2017 analysis prepared for the agency.[2] We constrained the model to hold total greenhouse gas emissions at the same level achieved in the Core Scenario (19.9 MMT CO_2/year). These two changes – significantly reducing the growth rate of customer-side solar and holding the GHG level constant – were the <u>only</u> modifications that we made to the model.

Q. What costs were assumed for the customer-side solar that was removed from the modeling run?

[2] Measure Proposal Rooftop Solar PV Systems, docketed January 18, 2018, at p. 17. Available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-BSTD-02.

A. The SB 100 model did not include resource costs for customer-side solar. Therefore, we used the resource costs that the model includes for "distributed solar", which were \$52/MWh in 2027, falling to \$42/MWh in 2045, with a 21 percent capacity factor.[3]

Q. How do those costs compare to the installation costs of residential rooftop solar?

A. The NEM 2.0 Lookback Study that was prepared for Energy Division for this proceeding assumed median installed costs for California residential rooftop solar of \$3.8/W_{DC}.[4] To put that figure in the same terms, \$3.8/W_{DC} equates approximately to \$230/MWh_{AC},[5] which would not include operating costs. This is approximately five to six times the "distributed solar" costs in the SB 100 model.

Q. What were the results of your analysis?

A. The present-value savings in the TRC in this case was nearly \$1.26 billion per year. The model simply replaced the customer-side solar (at "distributed solar" costs) with a combination of utility-scale renewable resources that it found to be most cost-effective, indicating that these resources were far more cost-effective in achieving SB 100 goals than customer-side solar. The complete results are shown in Attachment 2.

Q. How do these savings relate to the cost of the Net Energy Metering (NEM) program?

A. These are the total savings from the 50 percent lower level of customer-side solar based only on the saved capital and operating costs of distributed solar photovoltaics that were

[3] Table 31 of the SB 100 Inputs and Assumptions document. At p. 46, the document states "The NREL Annual Technology Baseline 'Mid' case projection is used to determine both capital costs and operating costs of solar PV resources for each forecast year. Both utility-scale and distributed solar PV cost projections use Annual Technology Baseline data."

[4] See NEM 2.0 Lookback Study (January 21, 2021) at p. 72. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M360/K524/360524821.PDF.

[5] Starting with the installed cost of \$3.80/W_{DC} for customer-side solar and a rather optimistic 1.1:1 for DC to AC conversion rate, I used NREL's simple Levelized Cost of Energy Calculator (https://www.nrel.gov/analysis/tech-lcoe.html) based on a 3% discount rate and 21% capacity factor to convert the customer-side solar fixed cost to \$/MWh.

assumed in the SB-100 Core Scenario. The model does not address additional savings, if any, that would accrue in association with the NEM program.

Q. Circling back to Mr. Siegele's statement ("California would achieve its GHG reduction targets more cost-effectively by accelerating NEM solar under the current NEM structure and de-emphasizing remote utility-scale solar dependent on new transmission construction."), what do you conclude?

A. If higher levels of customer-side solar were more cost-effective than utility-scale renewables, then the model would show additional costs – not savings – from reducing customer-side solar levels. Therefore, I conclude that the SB 100 model shows this statement to be false. Higher levels of rooftop solar substantially raise the overall cost of achieving California's GHG goals compared to relying on utility-scale renewables.

C. Implications for Land Use of Reduced Customer Solar

Q. CALSSA's testimony states, on page 83, lines 12-18, that the SB 100 report "indicates a need to nearly triple the amount of utility-scale solar built every year through 2045, which will be "an enormous challenge and will put pressure on land availability… If less distributed clean energy is built, even more utility-scale renewables will be needed." The testimony of Tom Beach for the Solar Energy Industries Association and Vote Solar, at lines 15-18 on page 21, states that distributed solar "has the societal (environmental) benefit of avoiding the land use impacts of utility-scale solar or wind generation." Did your SB 100 modeling results show a significantly greater need for utility-scale renewables generation with lower levels of customer-side solar?

A. No. The results show that the overall need for utility-scale renewables remains virtually the same when we reduce the growth rate of customer-side solar. Specifically, the need for utility-scale renewable energy increased by less than 1 percent (less than 500 MW). The overall need for utility-scale solar and storage capacity is reduced along with the substantially reduced level of customer-side solar. Thus, the overall need for additional resources is substantially reduced.

Q. Can you please interpret that result?

A. Yes. With more customer-side solar on the system, more battery storage is needed to shift daytime overgeneration to other time periods, primarily the evening net-peak period. As a result, less existing natural-gas-fired capacity is needed as those same storage resources help meet the system's resource adequacy (RA) capacity needs. Conversely, with less customer-side solar on the system, less battery storage is needed and more existing gas capacity is retained for RA capacity. Without so much storage on the system driven by customer-side solar, wind and geothermal resources – which produce energy outside of solar-production periods and generally have higher capacity factors than utility-scale solar – become more cost-effective.

Q. Can more gas-fired capacity be retained while holding GHG levels constant?

A. Yes. The gas capacity is present to meet RA capacity needs but is operated very rarely, hence, keeping the emission level at the same level as the SB-100 Core Scenario.

Q. What are the land-use implications of these findings?

A. I am not an expert on land use. However, the modeling results show that SB 100 goals can be achieved more cost-effectively with substantially lower levels of customer-side solar while barely increasing total utility-scale renewable energy capacity.

Q. Does this conclude your testimony?

A. Yes, it does.

CalWEA Attachment 1: SB 100 Inputs and Assumptions Report, Sections 4.2.7 and 4.2.8

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4.2.6.1 Solar Capital Cost Assumptions

The NREL Annual Technology Baseline "Mid" case projection is used to determine both capital costs and operating costs of solar PV resources for each forecast year. Both utility-scale and distributed solar PV cost projections use Annual Technology Baseline data.

The Annual Technology Baseline's solar cost data is location-independent (developed to be free of geographical factors) and regional adjustments are made to reflect California and out-of-state conditions, if material. Consistent with current industry practice, cost calculations assume a single-axis tracking system with a 1.35 inverter loading ratio for utility-scale solar and a fixed-tilt system with 1.35 inverter loading ratio for distributed solar. The inverter loading ratio measures the amount of DC solar cells per the inverters rated AC output. For example, a 10 MW-AC inverter would typically be used for a solar system with 13.5 MW-DC of photovoltaics.

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

4.2.6.2 Wind Capital Cost Assumptions

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

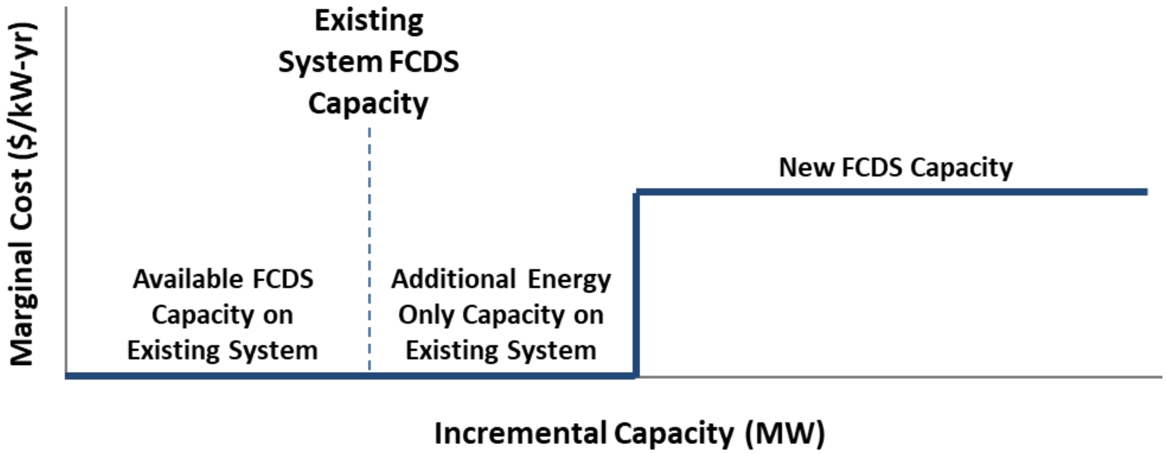
4.2.7 California Transmission Cost & Availability

Candidate renewable resources in RESOLVE are selected as **fully deliverable (Full Capacity Deliverability Status, or FCDS)** resources or **energy only (Energy Only Deliverability Status, or EO)** resources, each representing a different classification of deliverability status by CAISO. A resource with FCDS is included in RESOLVE's resource adequacy constraint and is counted towards system resource adequacy, as described in Section 7.1. An EO resource is excluded from RESOLVE's resource adequacy constraint, thereby not providing any resource adequacy value. The FCDS or EO status of a resource does not impact how it is represented in RESOLVE's operational module – the total installed capacity of the resource is used when simulating hourly system operations, regardless of FCDS or EO designation.

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

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

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



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

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

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

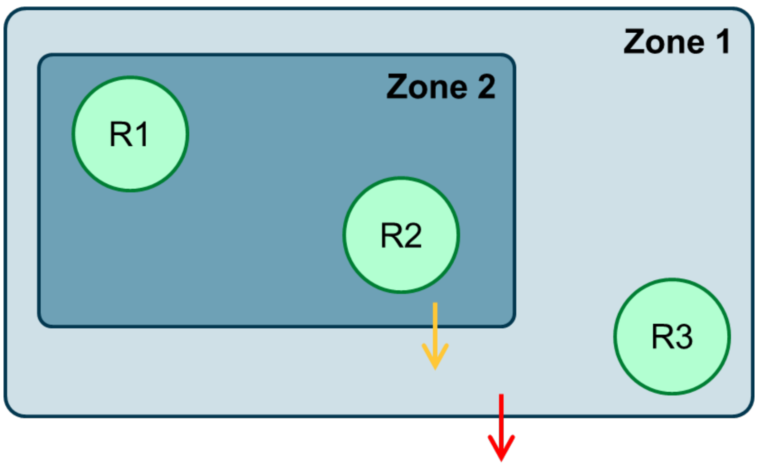
- Subtraction of baseline resource capacity that is projected to come online in 2019 or later from CAISO's transmission capability estimates. Resources brought online after 2018 must be allocated incremental transmission capacity because CAISO's transmission capability values include all resources online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

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

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

In the whitepaper CAISO identifies multiple layers of transmission constraints for many transmission zones. These "nested" constraints represent multiple concurrent limitations to delivering energy from renewable resource zones to load centers (Figure 4.3). While only one limit may be binding at a time, all limits must be modeled simultaneously to ensure that no limits are exceeded. In RESOLVE, nested constraints are modeled by allowing candidate resources to be assigned to multiple (nested) transmission zones. By allowing multiple assignments, a candidate resource counts towards the FCDS and EO limits in *all* of the zones and subzones to which it is assigned.

Figure 4.3. Diagram of nested transmission constraints



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

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

Table 35. RESOLVE transmission zone "nested" hierarchy

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

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

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

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

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

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

Table 36. Transmission availability & cost in CAISO

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

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

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

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

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

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

Table 37. Aggregated transmission capability of Ex zones

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

4.2.8 Out-of-State Transmission Cost

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

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

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

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

Resources that require new transmission to reach California are assumed to be delivered to a specific CAISO transmission zone or subzone. Each out-of-state resource must compete for CAISO transmission capacity with other candidate renewable resources located inside the CAISO system. The total cost to deliver out-of-state resources on new transmission to CAISO load centers is the cost shown in Table 38, plus any additional cost to develop transmission in CAISO transmission zones and/or subzones (Section 4.2.7) if the capacity of the existing CAISO transmission system is not sufficient. For New Mexico and Wyoming resources, the CEC

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

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

4.3 Energy Storage

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

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

4.3.1 Pumped Storage

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

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

CalWEA Attachment 2: CalWEA's SB 100 Modeling Results

		Core Scenario	Alternative Scenario
Present Value Portfolio Metrics	***Unit***		
PV Revenue Requirement	*$MM*	$ 856,182	$ 868,237
PV Total Resource Cost	*$MM*	$ 952,095	$ 940,446
Levelized Revenue Requirement	*$MM*	$ 47,917	$ 48,592
Levelized Total Resource Cost	*$MM*	$ 53,285	$ 52,633
Levelized Average Rate	*cts/kWh*	17.2	16.3

Annual Portfolio Metrics	*Unit*	2045	2045
Revenue Requirement	*$MM/yr*	$ 53,426	$ 54,328
Total Resource Cost	*$MM/yr*	$ 60,157	$ 58,899
Average Rate	*cts/kWh*	17.4	16.3
Greenhouse Gas Emissions including BTM CHP	*MMtCO2/Yr*	19.9	19.9
Effective RPS (incl. banked RECs)	*% of Retail Sales*	86%	89%
Renewable Curtailment incl. Storage Losses	*% of RPS Gen.*	7.2%	6.9%

Selected Resource Summary

	Unit	2045	2045
Gas	*MW*	-	-
Clean Dispatchable	*MW*	-	-
Clean Baseload	*MW*	-	-
Hydrogen Fuel Cell	*MW*	-	-
Biomass	*MW*	-	-
Geothermal	*MW*	135	1,019
Hydro (Small)	*MW*	-	-
Wind	*MW*	4,337	4,337
Wind OOS New Tx	*MW*	7,614	9,615
Offshore Wind	*MW*	10,000	10,000
Solar	*MW*	44,847	42,421
Customer Solar	*MW*	-	-
Battery Storage	*MW*	38,491	31,942
Pumped Storage	*MW*	3,243	2,394
Shed DR	*MW*	-	-
Gas Capacity Not Retained	*MW*	(7,861)	(5,766)
In-State Renewables	*MW*	59,319	57,777
Out-Of-State Renewables	*MW*	7,614	9,615

Selected Battery Duration		2045	2045
Pumped Hydro	*hr*	12	12
Li Battery	*hr*	4	4
BTM Li Battery	*hr*	-	-
Flow Battery	*hr*	-	-

Note: Optimized duration is a cumulative value reflecting all power and energy capacity built through the reported year.

Total Resource Summary			
	Unit	**2045**	**2045**
Nuclear	*MW*	1,042	1,042
CHP	*MW*	-	-
Gas	*MW*	25,098	27,193
Clean Dispatchable	*MW*	-	-
Hydrogen Fuel Cell	*MW*	-	-
Nuclear SMR	*MW*	-	-
Coal	*MW*	-	-
Hydro (Large)	*MW*	10,160	10,160
Hydro (NW scheduled imports)	*MW*	3,478	3,478
Biomass	*MW*	995	995
Geothermal	*MW*	2,779	3,663
Hydro (Small)	*MW*	1,388	1,388
Wind	*MW*	12,217	12,217
Wind OOS New Tx	*MW*	7,614	9,615
Offshore Wind	*MW*	10,000	10,000
Solar	*MW*	64,389	61,963
Customer Solar	*MW*	39,063	23,372
Battery Storage	*MW*	41,756	35,206
Pumped Storage	*MW*	6,302	5,453
Shed DR	*MW*	2,195	2,195
Shift DR	*MW*	-	-
Hydrogen Load	*MW*	-	-
In-State Renewables	*MW*	129,360	112,128
Out-Of-State Renewables	*MW*	9,084	11,085
Battery Storage Penetration	*% of peak load*	51%	43%
Gas capacity not retained (total, cumulative)	*MW*	7,861	5,766
Gas capacity not retained (economic, incremental)	*MW*	1,398	2,123
Gas capacity not retained (economic, cumulative)	*MW*	7,861	5,766