CPUC Staff Responses to Informal Party Questions Regarding the 2019-20 IRP Proposed Reference System Plan

12/5/19

Purpose: The purpose of this document is to provide parties with a list of informal party questions regarding the 11/6/19 Proposed Reference System Plan and CPUC staff's answers to those questions. This information will be publicly available on the CPUC website, and can be used to inform party comments and reply comments on the 2019-20 IRP Proposed Reference System Plan. Some content has been lightly edited/paraphrased for simplicity and clarity.

Party Name:	Party Question:	Staff Answer:
California Strategies	How are the benefits of pumped storage (PS) valued in RESOLVE that distinguish it from 4-hour battery storage (e.g., longer duration storage suitable for weekly and seasonal operation)?	RESOLVE has a 24-hour dispatch window, so the capability of PS to store energy beyond one day is not directly captured. However, in RESOLVE the capacity (resource adequacy) contribution of PS does not decline with increasing storage penetration (as opposed to battery storage, which has a declining marginal ELCC curve at higher levels of penetration). In practice, PS may need to store energy across days to be able to provide 100% of its capacity towards resource adequacy, thereby, at a high level, capturing some value of storing energy across days during times of system peak. PS and batteries both provide reserve products, with some minor differences. The longer duration of PS facilities relative to batteries makes it less likely that RESOLVE's constraints that restrict the amount of reserve that can be provided from storage based on available energy in the storage will impact the ability of PS to provide reserves (i.e. PS is likely more able to provide reserves than battery storage of the same power capacity).
California Strategies	Battery performance over the long term. Specifically, what assumptions are made about degradation of battery systems?	Degradation is assumed to be addressed through annual augmentation costs in RESOLVE's battery cost assumptions (annual augmentation cost assumption is 4.2% of installed cost of duration component of battery costs). Detailed cost and financing assumptions for all technologies can be found in the "Resource_Characteristics" tab of the RESOLVE_Resources Costs and Build Excel workbook. We consider augmentation to be an ongoing cost that's applied annually as a percentage of the installed cost assumption in that year, i.e. as battery installed costs decline so do augmentation costs. This is only applied to the energy component of battery costs.

California Strategies	What are the amortization schedules for PS vs battery storage?	PS has a debt period of 30 years, battery storage is 18 years. Detailed cost and financing assumptions for all technologies can be found in the "Resource_Characteristics" tab of the RESOLVE_Resources Costs and Build Excel workbook. The financing lifetime of BTM storage is 10 years and 20 years for utility scale, but the debt period is less than that. We assume the following relationship between lifetime and debt period (can be found at cell AP 97 in Resource_Characteristics tab of the RC&B workbook). [See table to the right]
California Strategies	Western Hydropower Availability - How much and when? What are the IRP assumptions about other states' "calling" in hydro as those states shut down baseload and go to renewables (notably, WA or OR).	The existing large hydro resources in each zone of RESOLVE are assumed to remain unchanged over the analysis timeframe. Load projections and resource retirements and additions in other zones are modeled in RESOLVE (and were derived from the WECC 2028 Anchor Dataset). Dedicated hydropower imports from the NW to CAISO are assumed to be constant at historical levels.
California Strategies	Have PS costs been benchmarked (and adjusted) against their commercial costs (as has been done for battery storage and other technologies)?	PS costs are highly site specific and there have been a limited number of recent projects, however E3 has compared the CPUC IRP cost assumptions with information from utility IRPs (for example, Pacificorp's 2017 IRP included a study on long-duration storage costs and quotes some pumped hydro cost estimates from HDR) and found them to be reasonably similar.
California Strategies	PS integration - What is assumed for pumped storage fleet versus calculated?	Unclear what this question is referring to – would need additional information to answer.
California Strategies	Western grid impacts - How much integration of the western grid is assumed and by when?	Balancing areas across the west are modeled as they are today through the study timeframe. The CAISO export limit is increased over time from 2000 MW to 5000 MW, which at a high level reflects increasing coordination between balancing areas.
California Strategies	Electric vehicle integration - In particular, how much of the excess solar generation is assumed to be absorbed by EV charging. What, if any, are the assumptions about two-way change and re-injection of stored power?	EV load is represented as a fixed load modifier in RESOLVE using charging shapes and total demand from the CEC's 2018 IEPR Update demand forecast. RESOLVE has the ability to simulate flexible EV charging but the default assumption does not include any. For vehicles that can charge flexibly, the optimal charging shape is constrained by the amount of vehicles that are plugged in, which defines how much charge capacity is available, and the instantaneous driving demand for that hour, which affects the state-of-charge of the fleet.

California Strategies	Demand response - How responsive is demand to variations in price? How much exposure to real time prices is assumed in the IRP?	Shed DR is not explicitly modeled in the hourly dispatch part of RESOLVE, it is only modeled as contributing to satisfying the PRM constraint, reflecting its effect of reducing demand during peak load conditions. Shift DR can be explicitly modeled in the hourly dispatch part of RESOLVE (and thus responsive to hourly system energy price) - it can move energy consumption within a day subject to constraints on the amount of energy that can be shifted. The 2019 IRP does not include a scenario in which shift DR is available for selection as a candidate resource. However, BTM storage resources, which in some cases could be considered a type of demand response, are modeled as responsive to hourly system energy cost. Some amount of BTM storage is included in the baseline of RESOLVE. It is available as a candidate resource.
Joint IOUs	Could you help us understand how the Battery Storage ELCC declination works in RESOLVE? a. How does the declining ELCC curve relate to battery penetration for durations greater than 4-hours? Consider Figure 10, which indicates that battery storage NQC fraction falls to 38% when 4-hour storage is serving 35% of the peak. If battery storage were serving 35% of the peak load and it was all 4-hour duration, what would be the NQC fraction for incremental battery storage units with 5 – 10-hour durations? b. Assuming the previous example, what is the NQC fraction of 2-hour storage? Is it 19% (half of 38%)? Please indicate where the NQC fractions for < 4-hour durations are indicated in the RESOLVE workbooks.	The ELCC curve was developed using incremental blocks of 4-hour storage. No analysis characterizing effects of different duration. If storage in RESOLVE is < 4 hour, its NQC would be prorated, i.e. 2 hour gets 50% of its NQC. Using the example above, if the ELCC was 38%, then the actual capacity value would be 19%.

Joint IOUs	Please elaborate on the changes to wind and solar resource potential. a. What were the interconnection and land use challenges provided in the wind industry's feedback, which led to the reduced potential for Greater_Carrizo_Wind (Attachment A, slide 41)? b. Please confirm that solar potential was reduced by 15 percentage points – from a 95% discount to 80% discount (Attachment a, slide 41).	a. There is very little development activity in this zone, as can be seen by the CAISO interconnection queue. Wind industry feedback indicated that this is due to siting constraints and difficult topography. b. The utility-scale solar potential was increased by 4x. The "95%" refers to the reduction applied to solar potential from the raw resource potential calculated using available land area. The reduction was reduced to 80%, thereby increasing the potential in RESOLVE significantly. Or said another way, we are now modeling solar capacity limits equal to 20% of developable land, instead of 5%.
Joint IOUs	Why was more gas generation retained when 2045 is included in the planning horizon?	Scenarios modeled through 2030 do not consider potential load growth and other changes assumed by 2045. The increased load in the long-term future makes it economic to retain more gas generation to meet reliability in the long-term.
Joint IOUs	Why do the lower GHG target cases select less Shed DR?	The larger amounts of renewables and batteries required for lower GHG targets also serve to provide effective capacity and reduce the need for a pure capacity product like DR.
Joint IOUs	Please provide a map representing the pipe and bubble transmission system used in SERVM. Please also provide the mapping from RESOLVE Resource Zones to SERVM zones.	See the Unified RA and IRP Modeling Datasets 2019 page and download Master Region Lookup and Transmission Flow Limits and Hurdle Rates in SERVM.
Joint IOUs	Can ED share a redlined version of the RSP from the June version?	A version of the I&A red-lined from the 10/4/19 version is now posted here.

Joint IOUs	Does the baseline resources list used in the RSP include additional resources from the August data request for updated contract and development status of resources? It was not clear what is included in the baseline resources from page 21 of the Input and Assumptions document. The reference source shows and "Error! Reference source not found" and is not linked.	No, the RSP baseline was not updated using LSEs' responses to data request, received in September 2019. The I&A error message on p.21 should simply refer to Table 15 on the next page.
Joint IOUs	How did ED determine storage costs (i.e. what studies were used?)	See section 4.3.2 of Inputs & Assumptions document.
Joint IOUs	Why are imports limited to 5,000 MW and not something higher?	To reflect historical levels of firm RA import contracts and future unwillingness of OOS generators to provide firm RA capacity or sell into CAISO markets during highest load conditions. One clarification: the 5,000 MW is only for the RA/PRM constraint. In RESOLVE's hourly dispatch in the 37 days, imports are limited to the CAISO simultaneous import limit of 11+ GW. SERVM's characterization of import constraints is on slide 11 of the Proposed RSP Validation with SERVM Reliability and PCM deck.
Joint IOUs	Will the OTC extensions from the procurement track be adjusted and reflected in the final RSP?	It's unclear what adjustments to modeling assumptions, if any, will be made to the version of the RSP in the proposed decision.
Joint IOUs	Can Energy Division post the list of Baseline resources so all LSEs can review? Currently they are embedded in the RESOLVE model and not all LSEs have the capability to extract and review for accuracy.	These assumptions are currently available in the upstream Resource Costs and Build RESOLVE Excel workbook, which should be included in the RESOLVE Model Results Package found here. Staff has also recently posted a more accessible workbook "SERVM Total Unit List for Proposed RSP with baseline and new resources identified." This link is found on the Unified RA and IRP Modeling Datasets 2019 webpage.
PG&E	When will the Clean System Power tool be released for review?	Likely by the end of 2019.
PG&E	How does RESOLVE calculate Marginal PRM Cost?	The PRM shadow price is the cost of meeting the Planning Reserve Margin (or Resource Adequacy) constraint for the year in question. The PRM shadow price reflects the total cost of building a resource to meet the capacity need in a single

	For instance, in 2021 of the "46MMT_20191104_SolarLimit_PartialOTCExt" case when PRM is binding, what cost components are being added to get to the $938 marginal PRM cost and are those costs netted against any revenues?	year, net of all future avoided and incurred costs (discounted back to the year in question). Future avoided costs include the energy and ancillary service value that the marginal capacity resource can provide, avoided costs related to GHG and RPS compliance, and avoided capacity costs in future years. Future incurred costs include fixed and variable operations and maintenance. As explained below, the PRM shadow price values from many RESOLVE runs can differ from the capacity cost typically used by vertically integrated utilities or seen in organized markets. A "typical" or "traditional" capacity cost is based a number of assumptions including: 1. A combustion turbine or other gas peaker is the marginal capacity resource 2. Energy and ancillary service revenues are small relative to the levelized fixed cost of the combustion turbine 3. There is a capacity need in all subsequent years None of the above assumptions hold perfectly for the proposed RSP RESOLVE results: 1. Given the necessary time to permit and construct a gas-fired resource, RESOLVE cannot build new gas-fired resources until the mid-2020s. Near-term capacity needs (before the mid-2020s) must therefore be met by other resources. Battery storage is frequently chosen by RESOLVE to meet the capacity needs before the mid-2020s. 2. Batteries have significant value providing energy arbitrage and ancillary services. This value generally increases over time as the GHG target becomes more stringent and as more renewables are installed, though values far into the future are weighed less heavily because they are discounted using a discount factor. 3. A binding GHG target in 2030 results in a large buildout of battery storage for the purposes of meeting the GHG target. Because RESOLVE is building battery storage to reduce GHG emissions, there is a surplus of resource adequacy capacity in 2030. This surplus is reflected by the PRM shadow price reaching zero in 2030. In summary, the need to reduce GHGs drives battery installation (as well as other resources that provide resource adequacy) by 2030, resulting in no incremental need for resource adequacy capacity.

		In the list above, (3) is likely the largest factor that explains why the PRM shadow price can go above the levelized cost of storage. By 2030 the value of providing incremental resource adequacy capacity has decreased to zero. As discussed above, the PRM shadow price is the marginal cost of constructing new capacity in a given year and operating that capacity over the entire simulation horizon, net of all value streams. Because the resource adequacy value stream is limited to a handful of years instead of the entire simulation horizon, less capacity value is netted off the installed cost of the battery than would be otherwise expected. Imagine a hypothetical extreme case – when there is only one year across the whole simulation horizon that has a capacity need. This could be caused, for example, by a resource retirement in one year and the scheduled addition of replacement capacity being a year late, resulting in a single "gap" year when new capacity is needed. In this case a single year would cause the model to build capacity, so the shadow price would reflect the total capital cost of the resource because the resource is only being built for a single year (net of any future energy, ancillary service, GHG, and RPS revenues). This hypothetical example is another way of showing that the PRM shadow price can go above the levelized capital cost of a resource because the levelized cost is an annualized value that spreads the capital cost over many future years. If capacity is needed for fewer years than the annualization timeframe, the PRM shadow price can increase to be much higher than the levelized capital cost value.
PG&E	Can you explain the economic retention logic further? From the documentation it appears that the Fixed O&M is compared to "the value of services provided to the system". What is counted in that valuation and how is it measured?	Retirement decisions are made by the model comparing the energy, AS, capacity value of a resource to the cost of FOM plus any operating or emissions cost.
PG&E	How is the ELCC for out of state resources determined for PRM purposes?	OOS resources serving CAISO load, whether delivered on existing or new transmission, have their ELCC determined in aggregate with in-state wind and solar using RESOLVE's ELCC surface.

PG&E	Does the dispatch logic for imports and internal resources account for the GHG price in the same manner?	Yes, unspecified imports and in-CAISO generation receive the same GHG cost (CARB floor price + GHG shadow price) per ton of CO2. The unspecified import rate is higher than in-CAISO CCGT generation, resulting in higher GHG costs. However, fuel prices outside of CAISO can also impact the balance between unspecified imports and in-CAISO gas generation. Operational constraints on resources within CAISO and outside of CAISO can also impact the balance between unspecified imports and in-CAISO generation.
PG&E	(7) Why is the basis for the "no new DER" case the 46MMT base case rather than the proposed alternative case with OTC extensions and a smoothed solar build?	Sensitivities – including the no new DER case - in the proposed RSP analysis were performed using core policy (base case) assumptions, not the 46 MMT Alternate. Parties should be able to view relevant inputs and results in the "inputs" and "results" folders for the "46MMT_20191104_NoDER" case contained in the RESOLVE .zip file. The contents of those folders should provide the ingredients needed to analyze the case, possibly without using the existing Scenario Tool or Results Viewer. Staff are working on a possible fix to make this simpler for parties.
PG&E	It appears ZNE PV is not counted in the "no new DER" case. Given this is part of the approved code it seems like it ought to be. Can you confirm this capacity is being excluded and provide the rationale for why? Both baseline and AAPV are removed in the no DER case.	All incremental BTM PV included in the IEPR forecasts was removed. The intent is to evaluate the benefits of DER that is added to the existing portfolio as of 2018. If the IOUs feel this is inappropriate, please provide an explanation in comments.
PG&E	Slide 168 indicates the shadow prices of Capacity and GHG would be used as direct inputs into the IDER ACC. a. On Capacity: Slide 83 shows a capacity "Shadow Price curve", indicating capacity will be approximately $1000/kw-yr in 2021 and $0/kw-yr in 2022. If the proposal is adopted, would these be the prices input into the IDER ACC for DER avoided costs? Is	a. As described in Answer 3 above, RESOLVE modeling has the effect of concentrating all the costs of a given resource in the year or years in which the binding constraint is driving its selection. Such a high price in a single year was not anticipated when developing the proposal to use IRP capacity shadow prices in the ACC. Further investigation re: the ACC proposal in the IDER proceeding may be needed to determine how to most appropriately translate IRP capacity shadow prices into annual $/kW-yr. system capacity avoided costs. b. The proposal for the IDER ACC is not to use the much lower IRP GHG shadow price in the years before 2030. The IDER ACC proposal is to discount the 2030 GHG

	the $1000/kw-yr a result of just new build storage or are there other resources that drive the price spike? b. On GHG: Slide 90 shows Marginal GHG Abatement Cost curves, which are the sum of the allowance cost and GHG Shadow Price. If the proposal is adopted, would the GHG shadow price curve that goes into the ACC follow a similar "hockey stick" trajectory as the planning price curve?	shadow price from the IRP at the utility WACC to calculate GHG avoided cost values for 2020 – 2029. This would be in place of the D. 18-02-018 approach of trending the value back to the current cap and trade price.
SDG&E	How did ED determine storage costs (i.e. what studies were used?)	Lazard's Levelized Cost of Storage 4.0 (2018), supplemented by NREL's Solar and Storage Report • Standalone storage capacity costs from NREL's solar + storage report • Storage paired with solar capacity costs come directly from Lazard (wholesale storage use case)
SDG&E	Why are imports limited to 5,000 MW and not something higher?	5,000 MW was chosen to reflect historical levels of firm RA contracts for OOS resources. Only RA imports are limited – dispatch on all hours of the 37 representative days uses a much higher import limit of ~11,000 MW.
SDG&E	Will the OTC extensions from the procurement track be adjusted and reflected in the final RSP?	There is no plan at this time to make the small adjustments necessary to align OTC extension assumptions.
SCE	When will the RSP be updated with 2019 IEPR data?	After adoption of the 2019 IEPR.
SCE	a. Page 32 of the slide deck states that the Baseline Resources include data collected up to the spring of 2019. This indicates that the Aug 2019 Baseline Resource data request information is not currently included the RSP Baseline Resources. Should LSE's include the Aug 2019 Baseline Resource data request information in their 2020 IRPs?	a. This will be addressed in future CPUC guidance for LSEs re: 2020 IRP filing requirements. b. Addressed in 11/20 MAG webinar. There is currently no plan to update the Proposed RSP assumptions further before the proposed decision on the RSP.

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<tr><td></td><td>b. Also, from the recent Procurement Track decision, how will the year 2022 baseline assumptions utilized in the PSP adopted in D.19-04-040, and to be clarified in a baseline posted by Commission staff no later than December 2, 2019, be used in this cycle of the IRP?</td><td></td></tr>
<tr><td>SCE</td><td>SCE has capacity expansion model that requires each resource's NQC fraction to be specified as an input. Would the following be a reasonable proposal for deriving RESOLVE model's assumption for the solar and wind NQC fraction?</td><td>RESOLVE's NQC fraction for wind and solar changes as a function of penetration. Depending on the application, marginal or average NQC values may be more appropriate. The proposed method below calculates an average ELCC (or NQC) value, which especially for solar will be much higher than the marginal value. Marginal ELCC values for solar and wind in each year can be found on the Dashboard of the RESOLVE Results Viewer. Also, the method below does not differentiate between the NQC of solar and wind – the method should be modified to account for the difference capacity value of these two resource types.

1. From RESOLVE_Results_Viewer → Portfolio Analytics tab, take the values from row 901 – Variable Renewable ELCC (Incl. BTM). For the 46MMT Core Policy case, this number is 10,043 MW for example.
2. Divide this number by the total amount of Solar and Wind energy found in the "Total Resource by Technology" section of Portfolio Analytics. These are from rows 78, 79, 83, 84, 85. Note this includes Customer_PV.
3. From 1. and 2., our calculated result is: $\frac{10{,}043}{(20{,}066+26{,}661+10{,}293+0+0)} = 17.61\%$</td></tr>
<tr><td>SCE</td><td>In addition to using the RESOLVE results to calculate renewable NQC fraction, we would like to better understand how the ELCC surface calculation works. We performed the calculations described on page 91 of Attachment C, which described the linear equation and taking the minimum over the 24 facets. Questions below:</td><td>1) Yes, the final result is a single number for the ELCC of the solar and wind portfolio. Each equation on the surface is evaluated in the course of the optimization, but only the minimum value for all equations in a given year is used as the solar and wind portfolio ELCC.
2) ELCC surface facet values are a product of many probabilistic reliability runs that take into account all hours of the day and night. The solar_coefficient values are not indexed over specific hours, rather the solar_coefficent values on the surface represent different combination of wind and solar penetration levels.</td></tr>
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	1) Does the ELCC surface linear equation return a single number to serve as the ELCC of both solar and wind? 2) Could you explain the intuition for why solar_coefficient is not 0 during night-time hours? Why do they take on the greatest values for hours 1 – 4? 3) In RESOLVE_Results_Viewer Dashboard, we see the Marginal Solar ELCC and Marginal Wind ELCC reported. Do these values relate to the parameters of the ELCC Surface Facet? 4) If so, how can we recover these values using the ELCC Surface Facet? 5) If so, what is used to differentiate Solar and Wind ELCC since the ELCC Surface Facet returns one number as a function of both solar and wind penetration? 6) In the same reporting, we see variables "Solar Capacity Factor for Marginal ELCC (input assumption)" and the same for wind. Could you please explain how this is used and what the implications are? Are these the capacity factors of renewables during the peak hour?	3) Yes, they represent the marginal ELCC of solar and wind from the binding facet in each period. Said another way, each facet has different marginal ELCC values for wind and solar – the marginal ELCC values shown in the results tool represent the "active" ones being used in RESOLVE. 4) This is a relatively complicated computation, the mechanics of which are shown in the export_results.py script that is part of the RESOLVE source code. 5) Both solar and wind capacities were varied when calculating the surface, so interactive effects of different wind and solar penetration levels are captured by the various points on the surface. The combined wind and solar ELCC is the sum of a marginal contribution for each resource type (either solar or wind), and an 'intercept,' which represents the additional ELCC that is added to the surface to make the total ELCC of the portfolio consistent with the marginal values. This is a way to address the problem of changing marginal ELCC values at different wind and solar penetrations. For example, as more solar is deployed, the marginal ELCC value goes down because each additional MWh of solar generation provides less and less capacity value. However, the initial MWhs of solar generation provided significant capacity value, so the 'intercept' of the surface adds an amount of ELCC to bring the portfolio ELCC up to the total. 6) The ELCC surface calculates the ELCC of the wind and solar portfolio on the basis of annual energy penetration of wind and solar. The Solar/Wind Capacity Factor for Marginal ELCC values are a simple way to allow RESOLVE to calculate the annual energy from wind and solar resources. They should be equal the capacity factor of the input wind and solar resource shapes.

SCE	We assumed that the variable ‘Firm Capacity Contribution’ in RESOLVE_Scenario Tool ‘Resources – Active’ worksheet was the NQC fraction of each resource. However, it seems that these values are also serving as the capacity factor for firm renewable resources such as Small_Hydro, Biomass, and Geothermal. Could you please explain how you interpret this variable?	NQCs for new firm resources adjusted downwards from 100% because the NQC values from existing plants of the same resource type had NQC values significantly lower than 100%. The costs of new firm resources assume a higher CF than the NQCs of existing plants imply, so the resource capacity factor was assumed for the NQC of candidate firm renewable resources.
SCE	We find that In-State solar resource potential was increased by 223% to 513,758 MWs compared to previous cycle’s 159,153 MWs. Could you please elaborate on this?	In the 2017-2018 IRP, candidate solar capacity as calculated from Black and Veatch geospatial analysis was discounted by 95% to reflect land use constraints and preference for geographic diversity. This value has been updated to 80% in the 2019-2020 IRP because geographic diversity is largely enforced by transmission limits. As a result, the solar potential reflected in Table 27 is four times the 2017-2018 IRP values for most solar resources.
SCE	We observe that out-of-state solar potential was reduced by 100% cycle-on-cycle. Could you please provide the rationale for this?	Out of state solar potential is included in the transmission screen that allows new transmission for all new out of state resource potential. Default assumptions include up to 3 GW of out of state wind on new transmission.
SCE	Would it be possible to provide a mapping of the current cycle Resource Names to the previous cycle’s RESOLVE Resource Names? This would assist us with understanding how our knowledge of the resource environment has changed in the last 2 years. We would appreciate the chance to compare our attempted mapping to your recommendation.	This is challenging because the geography of the underlying resource zones shifted between the two cycles. There is not a 1:1 mapping between the two datasets because of the shift in underlying transmission zone geography. Staff may be able to produce a map table, but the timing for release is TBD.

CEJA	(*paraphrased*) CAISO reported 2018 GHG emissions are approximately 54 MMT (data and analysis available here). RESOLVE shows 2020 GHG emissions of 45 MMT, a 9 MMT change from CAISO's reported 2018 value. What are the potential causes of this disconnect?	ED staff see at least two broad possibilities for the MMT difference CEJA points out: • As per the August 2018 MAG presentation (slide 7), it's possible that as much as ~4 MMT difference could be present simply because of differences in accounting methodology. We found systematic differences in emissions accounting between the values that CAISO reports and the RESOLVE/CARB cap and trade methodology, which we attempted to articulate on that slide. • Also, between 2018 and 2020 there have been additional renewable and storage deployment which could account for even more difference in the two datasets, potentially totaling several MMT.
CalWEA	The 46 MMT Scenario and 46 MMT Alternate Scenario both include about 2,800 MW of wind in 2030. Can you confirm that this "in-state" wind includes 800 MW from Baja and So. Nevada (since there are only 2,014 MW of in-state candidate wind resources -- Attachment C, Table 27, p. 40)?	Yes.
CalWEA	We believe that more wind should be included in the Tehachapi CREZ, given the queue activity. Was Tehachapi limited solely due to the environmental screens, and is it still possible to make adjustments?	The supply curve has 934 MW raw resource potential. For this zone, post-2018 COD contracts (132 MW) were subtracted from the raw resource potential. The supply curve shows that after this, and after the land use screens, 407 MW remain. Our schedule limited us to adjusting just the following zones for wind: Greater Carrizo, Northern California, Greater Imperial, S CA Desert.

CalWEA	We added up all of the CAISO WIND in Column P from the "cpuc_public_generator_list_servm_resolve" file, and it totals 7,485 MW, vs. 8,549 MW shown in Table 18 for 2020 (attaching my table). Since CAISO wind includes dynamically scheduled wind from OOS, I'm not clear what the difference is.	The difference is OOS resources that are contracted to CAISO (mostly NW wind). This information is available in the "Resources – Baseline" tab.
CalWEA	The Ruling states on p. 21 that the Commission estimates that there will be 1.5 – 2.5 GW of wind older than 25 years old by 2030 (i.e., built before 2005). Do you know what data source was used for the estimate? When I use the USGS database - https://eerscmap.usgs.gov/uswtdb/ - I get on the order of 1 GW built before 2005, FYI.	We used the RESOLVE baseline list of resources from last IRP cycle.
CalWEA	Apparently there is no BTM solar sensitivity as there was last time, only a "No new DER Case" which does not include cost-sensitivity information. Why is there no DER cost information? Do you plan to provide any such information?	The IDER analysis reflected in Appendix B was produced to support a staff proposal in the IDER proceeding. If there is a need for that cost information in IDER, we'd expect it to be discussed there.

CalWEA	The 46 MMT Alternate has OTCs running through 2023 (as the recent Commission decision does) plus 2 GW added in 2026 (vs. 3.3 GW by 2022 in the recent Commission mandate), and on the order of 2.5 GW of additional storage by 2024. Do you have any plans to run the model consistent with the recent RA resource mandate?	Unclear. There is currently no plan to update the RSP assumptions before the proposed decision on the RSP.
Direct Energy	Ss it possible to get the RESOLVE results for the solar and wind ELCCs by month through 2030? I know that RESOLVE has a surface that is used to calculate the ELCCs as the resources change, so just curious if the final RSP has numbers that can be pulled that show what the ELCCs were in the current RSP. Any insight you or E3 can provide, even something directional (such as declines by X percent per year) would be helpful.	Rows ~181-186 of the Dashboard tab of the RESOLVE Results Viewer excel sheet provide the total ELCC of the wind and solar portfolio, and the marginal ELCC of solar and wind for each modeled year. RESOLVE does not calculate monthly ELCC values, nor does it impose RA requirements on a monthly basis - the planning reserve margin/resource adequacy constraint is for the entire year. The RESOLVE Results Viewer is available as part of the RESOLVE Model and Results Package .zip file here.
Gridliance West (GLW)	(*paraphrased*) Why do RESOLVE capacity factor assumptions (for southern NV renewables in particular) differ as much as they do from what we seem to think the NREL data shows and from what seems to be supported by the databases referenced in the IA manual?	The reasons why RESOLVE's capacity factors for specific solar and wind resources are lower are: Solar: The capacity factor of the Potential Southern Nevada profile is lower than that in the Potential Southern California Desert profile because the Southern Nevada profile is comprised of a diverse set of locations in Nevada, that include regions of slightly lower solar resource than the immediate area around Las Vegas and that found in the Southern California Desert. Wind: The potential Southern Nevada profile is comprised of sites with lower capacity factors than the best sites in the Southern California Desert (Tehachapi Pass) area of California. For "out of state" wind to achieve the high capacity factors that the commenters specified (in the neighborhood of 45%), they would have to seek potential wind sites from New Mexico or Wyoming. We modeled both New Mexico and Wyoming potential wind as having capacity factors above 40% (41% and 46%, respectively).

		Background on site selection and shape origin for wind & solar resources: Solar (from NREL's National Solar Radiation Database): • In-state, candidate: E3 Candidate methodology draws on the California B&V study to identify solar capacity (MW) values for the CREZ regions, but these do not include specific coordinates for potential sites. E3 uses the coordinates given for California wind potential within the respective zones as a proxy for potential solar sites. E3 samples historical solar data from NREL's National Solar Radiation Database (NSRDB) at the selected sites and aggregates the site-level data by CREZ. Each CREZ is represented by 3-6 sites depending on its size. • OOS, candidate: B&V WECC study identifies regional zones - "Western Renewable Energy Zone" (WREZ) - for both wind and solar and a corresponding potential capacity (MW) in that zone. The boundaries of these zones are well-defined, so a random sample of coordinates, proportional to the size of each WREZ, is used to generate aggregate profiles of wind and solar for each zone. The same sampling technique was used to produce these profiles - sampling historical solar data from NSRDB. • Existing: For existing utility-scale solar, the EIA has a database that includes location coordinates, capacity, fixed vs tracking, tilt angle for each plant in the US. E3 uses this data to sample profiles from the NSRDB to produce state-by-state aggregate profiles of solar output. Wind (from NREL Wind Toolkit): • In-state, candidate: The B&V study for California identifies wind sites with specific coordinates, a regional zone - "California Renewable Energy Zone (CREZ)" - the site falls into, and a capacity (MW) value available at that site. E3 uses this data to sample historical wind data from NREL's Wind Toolkit for each site, and aggregates the site-level data by CREZ. • OOS, candidate: B&V study for WECC only identifies regional zones - "Western Renewable Energy Zone (WREZ)" and a capacity (MW) value for the potential in that zone. The boundaries of these zones are well-defined, E3 uses a random sample of coordinates, proportional to the size of each

		WREZ, to generate aggregate profiles of wind for each zone. The same sampling technique was used to produce these profiles - sampling historical wind from NREL's Wind Toolkit. • Existing: For existing utility-scale wind, E3 uses the EIA database that includes coordinates, capacity, hub height, turbine type and technology for each plant in the US. This data was used to sample the shapes from the Wind Toolkit to produce state-by-state aggregate profiles.
Gridliance West	(paraphrased) It is unclear how Baja resources are treated in RESOLVE, particularly as it relates to transmission costs. They appear to be directly connected to CAISO at zero cost. Can you please provide more detail?	The amount of available Baja wind resource potential is reduced in current modeling to the level of Baja wind projects in the CAISO interconnection queue to capture current commercial interest. Some of Baja's wind resource is very close to the CA border and would therefore not require any additional transmission. We are assuming that the commercially viable projects do not require new transmission. If the full amount of Baja wind resource was made available to the model, we would want to incorporate the cost of new transmission to access it.
Gridliance West	The RESOLVE_Resource cost and build workbook, supply curve sheet, shows the relevant resources (NV_SW_S and NV_WE_S) to have a lower levelized cost that the Riverside Palm Springs and the Greater Imperial solar resources. That's straight forward and would suggest that that NV_SW_S and NV_WE_S would get sited over Riverside and GI solar up to some constraint that causes a cost to be applied. So why don't NV_SW_S and NV_WE_S get selected up to the remaining FCDS limit in GLW?	Because California's regional cost multiplier is higher than NV's, Southern Nevada solar has a lower levelized fixed cost than Riverside Palm Springs and Greater Imperial solar. However, the resource profiles of Riverside Palm Springs and Greater Imperial have slightly higher capacity factors than Southern Nevada (see the Resources Variable tab in the Scenario Tool) so when Resolve is co-optimizing investment and dispatch the higher CFs are offsetting the difference in capital cost.

Gridliance West	The RESOLVE_Resource cost and build workbook, list sheet, seems very mixed up. It shows (columns J, K and L) that the electrical zone "SCADSNV_Z2_GLW_VEA" is mapped to a resource "GLW_VEA". But this "GLW_VEA" resource shows up no other place in this workbook. It doesn't for example, have a "first year available" value, and it doesn't have a capacity factor. And the "Southern_Nevada" resource in the columns J, K and L is mapped to "SW" instead of being mapped to "instate".	The list is used for grouping the individual rows in the supply curve into Resolve resource names. There aren't any supply curve entries with the electrical zone "SCADSNV_Z2_GLW_VEA". It probably should have just been removed entirely from that table to avoid confusion. Southern_Nevada resources are physically located outside of the state but connect directly to CAISO so there is no additional cost for building new OOS transmission to access this resource, but they are also not subject to the CA cost multiplier. In the modeling they are treated as in-state resources, however that mapping occurs in the Scenario Tool "Resources- Active" tab. This means that Southern_Nevada (and Baja) resources are assigned a physical zone of CAISO and are therefore not subject to any hurdle rates.
	The IA also seems very mixed up. In it the Southern_Nevada resources are listed as "out of state" resources (table 32). The Southern_Nevada resources have an "*" by their name, but I cannot find any reference to what the "*" means. And these resources in this document are shown as having more expensive levelized costs than the Riverside and GI levelized solar costs. Why this shows a higher cost for Southern_Nevada resources than does RESOLVE is unknown. But the IA document does show that there is a $7.35 hurdle rate from SW. So if the Southern_Nevada resources are mapped to SW in resolve and cause the addition of a $7.35 hurdle rate that could explain the results.	The LCOEs in the I&A are not direct inputs into Resolve and are calculated using the CFs in the supply curve and shown in the I&A for comparability with PPAs. Southern Nevada resources have a slightly higher LCOE due to lower supply curve capacity factors. The direct cost inputs into Resolve are the levelized fixed costs of the resources. The "*" indicates the resource is assumed to directly interconnect to the CAISO system. See above for hurdle rate explanation (Southern Nevada isn't subject to import hurdle rates).

	The real telling part is that we exercised RESOLVE to see what we have to do get RESOLVE to site solar in GLW. Not until we more than double the capacity factor of SNV solar – that is raise it to over 75% - does RESOLVE site SNV solar. So there must be some other cost being attributed to GLW solar than just the levelized cost of the new build.	On the face of it this is an unexpected result, so it would be good to understand better how you tested this. The primary way in which the RESOLVE optimization simulates renewable capacity factors is by the hourly "shape" parameters associated with each resource (in the Resources – Variable tab of the Scenario Tool). To have the modified capacity factors flow into the optimization, the hour-by-hour shape of Southern Nevada Solar would need to be modified. Could you confirm that you modified the hourly shapes when performing the experiment, and if so, briefly describe the method by which you increased the energy production in various hours? There are also capacity factors in the Resource Cost and Build workbook that are used only to calculated the LCOEs of the individual resources in the supply curve. These LCOEs are not inputs into Resolve, they are just shown for comparability with PPAs.