Q & A Following the 6/17/2019 IRP Modeling Advisory Group Webinar

Party	Date received	Party question/comment	Response
California Environmental Justice Alliance (Deborah Behles)	6/18/2019	In yesterday's MAG meeting, we didn't hear any mention of modeling work that is being conducted related to criteria pollutant emissions and how the modeling will be changed or improved from the last cycle. Will this be addressed in a future meeting or is there an update related to this?	Staff is considering the improvements proposed in the 2019 I&A document (11/29/18 Ruling Seeking Comment). Staff has no updates at this stage of the process.
California Independent System Operator (CAISO) (Delphine)	6/17/2019	On page (slide) 81. Do the numbers in purple reflect: COI, PDCI, total, CAISO's share, something else?	Total transfer capability from CAISO to NW (4293 MW) and NW to CAISO (5088 MW) based on WECC 2015 Power Supply Assesment. Values may be updated in RESOLVE if updated in SERVM. Transfer limits represent CAISO's share of all lines between the NW and CAISO.
California Independent System Operator (CAISO) (Delphine)	6/27/2019	In the last IRP two-year cycle, the Reference System Plan produced a Default Scenario portfolio which was used as the reliability base case in the CAISO's Transmission Planning Process (TPP) as well as a 42 MMT Scenario portfolio which was used as the policy-driven assessment to identify Category 2 transmission solutions in the TPP. What is the expectation for the resulting portfolios for this Reference System Plan? The CAISO requests that a single portfolio is used for both the reliability and policy-driven base cases.	Staff anticipates that the chosen Reference System Portfolio will likely serve as both the reliability and policy-driven base case in the next TPP cycle. However, the Commission will ultimately make the decision early next year.
California Independent System Operator (CAISO) (Delphine)	6/27/2019	On page 7, a workshop is scheduled in October on the Proposed 2019 Reference System Plan. The CAISO requests that modeling parties are afforded time at the workshop to present preliminary results.	Staff is planning for this workshop to be a full day in order to provide opportunities for other parties to present their own analysis results of the Proposed RSP. If parties do not have analysis complete by the time of the workshop, formal comment is a subsequent opportunity to share results.

California Wind Energy Association (Dariush Shirmohammadi)	6/17/2019	Were CAISO's proposed methodology for deliverability reflected in the numbers provided on page 85 "Input Estimates Received from CAISO"?	No, the CAISO presented a Deliverability methodology Issue Paper to stakeholders on May 2, and they are still in the process of responding to stakeholder responses on the issues discussed during that meeting. At this time the CAISO does not have a specific proposal for revising the deliverability methodology.
California Wind Energy Association (Nancy Rader)	6/18/2019	Best practice would be to vintage resources so that resources that have already received ELCC values in the RA context continue to be tagged with those values, but new resources get incremental ELCC values. If that is not possible, the most current ELCC values should be used (i.e., those that are about to be adopted in Track 3 of the RA proceeding); otherwise, using the previous average ELCC values will further exaggerate the value of new resources.	In the IRP portfolio ELCC calculations and Planning Reserve Margin assessment presented last year September 2018, staff believes that on a system portfolio basis, wind and solar capacity contribution was properly accounted for. Issues about vintaging of RA value assigned to specific groups of resources should be taken up in the RA proceeding.
California Wind Energy Association (Nancy Rader)	6/18/2019	Experience has shown that RESOLVE and SERVM calculate significantly different results for some critical parameters. One of these is the level of renewable curtailment, where the more-accurate value calculated by SERVM is 3 times that of RESOLVE. How do you plan to resolve the discrepancy?	Staff is completing major input updates for both models concurrently. A major improvement will be using common source data for both models to the greatest extent possible. This should bring the outputs of both models closer together. Staff will iteratively run both models, compare outputs, and make adjustments to one or both models to reduce the differences in outputs. Until staff runs both models with the input updates for the first time, it is difficult to predict how challenging it will be to make the models consistent with each other or what these adjustments might be.

California Wind Energy Association (Nancy Rader)	6/18/2019	We are pleased that the model will be accounting for repowering. However, it appears that existing biomass and geothermal resources will have an indefinite life. All existing resources should be treated the same, where they are retired if continued operation is not economic (as Gregg Morris suggested in his comment with regard to biomass), or repowered if that is economic. What we would not want to see is existing wind being removed from the baseline, with repowered wind placed in the supply curve, while existing biomass and geothermal get indefinite lives in the baseline. This is because wind repowers are likely to be more economic after biomass and geothermal are retired because the resource mix would be less diverse.	Given wind's prominence in the early years of the IRP planning horizon, and that a significant portion of California's existing wind that may reach the end of its useful life before 2030, staff propose prioritizing adding the functionality and data for this technology. Staff would then work with stakeholders to address other technologies. If the dynamics between technologies that you describe become evident in the modeling and are to the detriment of the planning process, then there is the possibility to "turn off" the repowering functionality.

California Wind Energy Association (Nancy Rader)	6/18/2019	Only storage which is under CAISO control should be modeled as storage. Other storage should modeled as load or supply-portfolio modifiers. (Batteries not under CAISO control are likely to be deployed to benefit customers by avoiding utility demand or energy charges, rather than to benefit the system.)	BTM storage included with the IEPR does not have an hourly shape associated with it. It only has an annual peak reduction effect and a very small increase in annual electric demand due to round trip losses from charging/discharging. Rather than replicating this simple representation, staff proposes to model all BTM storage like a supply resource. This way the hourly charge/discharge behavior of BTM storage can be more explicitly modeled in RESOLVE and SERVM. Staff understands that BTM storage may have substantially different behavior in actuality than centrally-dispatched grid-connected storage. Staff is still developing operating parameters/constraints for BTM storage and will create a separate resource type for BTM storage from grid-connected storage so that they can be dispatched differently in the models. Staff invites feedback on ways that BTM storage behavior can be reflected in the dispatch methods used in models like RESOLVE and SERVM.
California Wind Energy Association (Nancy Rader)	6/18/2019	Given that the primary driver for wind and solar generation is meteorological conditions, it is critical that BTM PV is represented as a supply resource (not a load modifier) because it will not behave like load. How will the SERVM modeling (with BTM PV modeled as supply-side resource) be reconciled with RESOLVE? If possible, RESOLVE should also treat BTM PV as a supply resource.	RESOLVE has, and will continue to represent BTM PV as "supply". RESOLVE, similar to SERVM, backs BTM PV effects out of the demand forecast and explicitly models BTM PV like a supply resource.
California Wind Energy Association (Nancy Rader)	6/18/2019	If possible, offshore wind should be forecasted and modeled using reasonable data proxies.	Staff will consider the information it has available about offshore wind.

Calpine (Matthew Barmack)	6/17/2019	We have been looking harder at developing CCS projects, either as retrofits to existing units or new resources. In addition, several recent studies have considered CCS for California, including https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5ced6fc515fcc0b190b60cd2/1559064542876/EFI_CA_Decarbonization_Full.pdf (See the section beginning on p. 79. There are very crude cost estimates at the top of p. 82.) and the study summarized in slides 3-6 of this https://energyatkenanflagler.unc.edu/wp-content/uploads/2019/04/Benson-CCUS-Prospects-and-Challenges.pdf I suspect that we could provide the detailed cost estimates that underlie either or both of these studies (or cost estimates from other sources including vendors).	Thanks for keeping staff informed. Adding CCS as a RESOLVE candidate resource is out of scope for this cycle but something to consider for the next cycle.

Calpine (Matthew Barmack)	6/19/2019	With respect to Pmins and ramp rates for CCGTs, I would encourage you to adopt the same approach as (I believe) the CAISO uses in calculating Effective Flexible Capacity, i.e., they treat the 1x1 Pmin as the Pmin of a plant and then calculate a weighted average ramp rate that reflects the average rate at which a plant can move between 1x1 Pmin and Nx1 Pmax accounting for transition times. There are infinitely many ways that a CCGT can move between 1x1 Pmin and Nx1 Pmax. Here is an illustration of one potential way: suppose a 550 MW 2x1 CCGT has a 1x1 Pmin of 180 MW. From 1x1 Pmin, the plant could start its second CT immediately. It would then take 45 minutes to transition to a 2x1 Pmin of 330 MW, from which the output of the whole plant could be increased at 20 MW/min to reach its full output in 11 minutes. In total, it would take the plant 56 minutes to increase its output by 370 MW (550 MW-180 MW), i.e., its weighted average ramp rate would be ~6.6 MW/min. (Another potential path would involve the plant first ramping to its 1x1 Pmax (260 MW), the speed of this ramp would be slower (10 MW/min for 8 minutes) than the ramp in the previous example because it would involve only 1 CT. From 1x1 Pmax, the plant might have the same transition time (45 minutes) as in the previous example but would end up at an output level above 2x1 Pmin (~400 MW). It could then ramp at 20 MW for 7.5 minutes to reach 550 MW. The total time to reach the plant's Pmax from 1x1 Pmin would be slightly longer than in the previous example (60.5 minutes	The CPUC has standardized all CCGT ramp rate and Pmin data using the following steps. -For IRP modeling purposes, staff converted all CCGT Pmin's to 1x1 Pmins where necessary (the sum of the steam unit's Pmin and one CT's Pmin). -CAISO CC Pmins were already 1x1, so staff used the data as-is and made no changes. - For out-of-CAISO CC Pmins from the WECC Anchor Dataset (ADS), the CPUC used the 2017 edition of an EIA dataset available here https://www.eia.gov/electricity/data/eia860/ to get information on the CC's CT and steam subunits. Staff used the 3_1_Generator_Y2017.xlsx table, and crosswalked its generators with the CPUC list of generators. Staff then calculated 1x1 Pmins for each CC by adding the PMin's of the average CT and the steam unit. -Staff calculated a weighted average MW/hour ramp rate by adding the ramp time required both for the individual subunits to ramp up from Pmin to Pmax, and the transition time between modes (e.g. 1x1 to 2x1). For example, a 2x1 generator would have 1 transition when ramping to Pmax, and a 3x1 generator would have 2 transitions. As a placeholder, staff assumed a transition time between modes of 45 minutes. This value was derived from a PJM study available here. https://www.pjm.com/-/media/committees-groups/user-groups/ccoug/20161108/20161108-item-02-spp-model-overview.ashx . See page 9 for a transition time table. Staff used the 2x1 value. Staff welcomes parties with more granular transition time data to provide it.

		instead of 56) for a weighted average ramp rate of 6.1 MW/min.) I think that it is important to represent the Pmins of CCGTs as their 1x1 Pmins and not overstate the "Pmin burden" associated with CCGTs and its impact on renewable curtailment, for example. FWIW, our CCGTs frequently turn down to 1x1 Pmin, for example, in the middle of the day when there is lots of solar on the system.	

Calpine (Matthew Barmack)	6/19/2019	With respect to PRM, I am not sure that I agree with the manner in which you are proposing to back out the avoided PRM associated with BTM resources from the PRM calculation. Your treatment seems consistent with current RA counting conventions, which might be your goal. On the other hand, way back when, presumably explicitly or implicitly, the PRM was selected to maintain a certain level of reliability. Ascribing an avoided PRM to BTM resources will lead to lower reliability as BTM grows, because, as you point out, the approach involves carrying no reserves for the load that is served by BTM resources. (I think that this impact was quantified in the CES-21 study. For example see Tables 4.4 and 4.5 of http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M195/K586/195586923.PDF which demonstrate that a higher PRM is required to hit the same reliability target when EE is treated as a load modifier instead of supply.) Maybe your treatment ultimately doesn't matter if portfolios are checked in SERVM for reliability. The SERVM validation should identify instances in which a particular BTM RA counting convention leads overall reliability to fall below target.	The treatment of BTM resources without reserves is related to the PRM in RA, and consistency with RA conventions was staff's goal, as you surmised. Staff will validate reliability in SERVM, which will assess the effects you mention. Staff expects SERVM results will show how much reserves ought to be carried.

Clean Coalition (Sahm White)	6/17/19 (asked in webinar)	Please provide more information re: transmission costs	New Tx costs use financing assumptions from the RETI2.0 process. They include overnight costs which are annualized using AFUDC (Allowance for Funds Used During Construction) of 117.5% and Annualization factor/RECC (Real Economic Carrying Charge) of 11.27% + any wheeling costs associated with getting power to CA border Cost of new Tx ($/kW-yr) = Overnight capital ($/kW)* 117.5%*11.27% + wheeling costs ($/kW-yr)
Gridwell Consulting (Kallie Wells)	6/18/2019	I am hoping to discuss various ways/options the CPUC may be incorporating hybrid resources into the next IRP modeling efforts.	Staff is open to hearing from parties interested in providing information on how to represent hybrid technologies in models.
Protect our Communities (Tyson Siegele)	6/17/2019	Based on the MW of of battery capacity shown on slides 28 and 29, it appears that EV batteries and their grid balancing characteristics are going to be considered in their own category is that correct? Can you share how that will be incorporated into the modeling?	Slides 28 and 29 do not include EV batteries. The effects of EV charging are included in the IEPR demand forecast assumptions. An hourly profile representing EV charging is a component of the IEPR demand forecast.

Protect our Communities (Tyson Siegele)	6/17/2019	The cost of batteries is falling. The benefits for batteries are increasing with the roll-out of TOU pricing. Based on that, I would have assumed battery installations in the second half of the 2020's growing faster than the first half. However, the slide 28 chart shows a straight line installed growth of batteries and slide 29 shows zero new capacity after 2024. Am I misinterpreting the graphs? Something else that I'm missing?	Slide 28 and 29 illustrate a baseline projection of BTM and grid-connected storage currently installed or under construction. Any storage candidate resources selected by RESOLVE would be incremental to the baseline. RESOLVE considers future cost reduction of storage and changing grid needs as it decides whether to select more storage incremental to the baseline. Baseline shown on slide 28 and 29 is intended only to capture storage projections outside RESOLVE's capacity expansion function. Thus, slide 28 shows an IEPR-based linear projection of BTM storage, while slide 29 only shows "committed" storage that should be fixed as input to RESOLVE, i.e. already contracted/online storage, and mandated amounts of procurement.
Protect our Communities (Tyson Siegele)	6/17/2019	I was also interested in the answer to the question asked toward the end of the webinar where the E3 representative said he would get back to everyone on the issue. Could you clarify the cost inputs for new transmission? Do the assumed costs include lifetime financing costs and O&M costs? If so, could you share the assumed costs?	See above response to Clean Coalition question.
Protect our Communities (Tyson Siegele)	6/17/2019	The hourly wind and solar profiles portion of the presentation was great. Can you elaborate on how wind and solar projects paired with on-site storage will be treated vs. standalone wind and solar?	Staff does not have explicit modeling representation of hybrid resources at this time but is receptive to hearing from parties on how it could be developed.
Public Advocates Office (Helena Oh)	6/20/2019	CAISO aggregated RPS resources by generator type for each region in their Plexos model. Did Energy Division treat RPS resources similarly or did you model each RPS resource as individual generators in SERVM? SCE modeled RPS resources individually in their Plexos model, for example.	SERVM models all generating resources individually, including renewable resources. CPUC cannot meaningfully comment on CAISO's approach without pursuing deeper examination of CAISO's model results and input datasets.

		Any thoughts on CAISO's approach?	
Public Advocates Office (Helena Oh)	6/20/2019	CAISO grouped storage resources by 1) whether they were 2-hour, 4-hour or 6-hour duration batteries, 2) whether they were customer-connected (BTM), distribution-connected or transmission-connected and 3) by region. How did Energy Division model battery storage in SERVM? Any thoughts on CAISO's approach?	All storage will be modeled as a supply-side resource in SERVM. Energy Division updated the Baseline in SERVM by taking the greater of the AB2514 mandated capacity per interconnection domain and actual procurement progress (informed by a data request to LSEs to obtain key data on storage owned/contracted). Staff aggregated the results into 10 generic storage resources per CAISO region (PGE Bay, PGE Valley, SCE, SDGE) to preserve data confidentiality and reduce model complexity (using individual battery units in the model would substantially increase model runtimes). Batteries were grouped into 2 hours duration or 4 hours duration, based on the results of the data request. CPUC cannot meaningfully comment on CAISO's approach without pursuing deeper examination of CAISO's model results and input datasets.
Public Advocates Office (Helena Oh)	6/20/2019	Finally, we would like to update the properties of the thermal generators in CAISO's model with more accurate data wherever possible. SCE provided us with their Plexos model which contains confidential data about each of the generators they have contracted with. Would you be able to share with us the data you used in SERVM for the thermal generators in the other regions?	Staff can share the complete SERVM database, including confidential unit-specific data, with the Public Advocates Office in their capacity as an independent organization WITHIN the CPUC that advocates on behalf of utility ratepayers.

Public Advocates Office (Radu Ciupagea)	6/20/2019	The Public Advocates Office recommends that in the upcoming IRP cycle the Energy Division and Commission require parties that submit modeling results of the reference system plan and/or the hybrid conforming portfolio to identify the resources used in the modeling in a manner that allows comparison of the resources across models. This would promote transparency and facilitate the ability to compare results. We attempted to compare the Energy Division's SERVM results with the CAISO's PLEXOS results of the Hybrid Conforming Portfolio, but the process was stymied by the CAISO's use of different resource names than the Energy Division's resource names. We requested the CAISO resource IDs directly from the CAISO in order to facilitate the comparison, but the CAISO objected and refused to provide the information on the basis that it was burdensome. We reached out to Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) and they both agree with our proposal. SCE proposed that the "Resource ID" from the "Master CAISO Control Area Generating Capability List" should be used in various IRP activities and the different models such as RESOLVE and SERVM. The Public Advocates Office and PG&E agree with SCE's proposal. The Public Advocates Office further recommends that parties who model the reference system plan or the hybrid conforming portfolio in any IRP cycle should use the CAISO resource ID or a name that is similar to the CAISO Resource ID in their models. If a resource does not have a CAISO resource ID then the party should use the resource ID used in the Energy Division's	For units in the CAISO footprint, Energy Division uses CAISO resource IDs where available as the single identifier for a generator. For generators outside of CAISO the WECC ADS "Generator Name" is used. Energy Division encourages all parties to the proceeding to do the same, or provide a crosswalk between their generators' identifiers and the CAISO resource ID's, in order to facilitate comparison across the models.

		master WECC-wide generator list. It is our understanding that Energy Division favored the CAISO resource ID whenever possible when creating this list. If parties include resources that are not a part of this list, then these parties should flag those resources.	

Resero (Ellen Wolfe)	6/19/2019	I had a question in preparation for preparing some more complete comments in response to the MAG workshop. I've helped GridLiance West submit comments a few times (Oct 2017, Oct 2018, and Jan 2019) asking for updating of the S. Nevada solar and wind capacity factors. If by chance you all have made those revisions for the '19 -20 RESOLVE assumptions? If so then I won't again burden you with comments from GridLiance on this issue. But if you haven't made those changes then we'll ask once again for those changes to be made.	No updates to RESOLVE renewable resource capacity factors have been made to date, but it may be possible for Staff to update RESOLVE renewable resource profiles and capacity factors. Staff cannot commit to updating due to scheduling constraints, but will assess whether it is possible to do so before the release of the proposed Reference System Plan analysis.
San Diego County Water Authority (Andrea Altmann)	6/17/2019	The Modeling Advisory Group webinar as well as the 2017-2018 IRP relied heavily on hydro imports from the Pacific Northwest. Given that Oregon and Washington may use their own hydro to achieve clean energy and greenhouse gas reduction goals, what alternative hydro resources is the CPUC anticipating modeling?	Staff performed extensive analysis of hydro dispatch and import patterns over the previous several years of historical data and presented results at the IRP workshop in January 2019. That work informs the updated assumptions to be used in RESOLVE and SERVM this year. The amount of energy available from specified NW hydro imports will be based on average historical values reported to ARB and the yearly availablility of these imports remains constant. This specified hydro is from BPA and Powerex (British Columbia). Other NW hydro (which may be imported as unspecified) is also assumed to remain constant at current levels. The amount of resource adequacy capacity available from NW hydro is not directly specified in RESOLVE, but the total RA import availability (which includes any RA from hydro) will reflect historical RA contract levels.

San Diego County Water Authority (Andrea Altmann)	6/17/2019	Previously the CPUC stated that it limited the amount of in-state hydro resources that it modeled due to proposed drought conditions. Has the CPUC considered modeling proposed hydro projects where the hydro resources being used are resources that could be used for both energy and water projects, such as emergency storage/drought-proof reservoirs?	Hydro operations in CAISO are constrained in terms of the daily energy budget, min, and max output. These constraints are based on actual CAISO operations from the appropriate hydrological year (low = 2008, mid = 2009, high = 2011). RESOLVE does not currently include any candidate large hydro projects, but allows investment in pumped storage projects.
Southern California Edison (Kathy Wong)	6/17/2019	On page 7 of today's presentation deck, the schedule calls for a Feb. 2020 Decision for the 2019 RSP which is similar to what we saw for the previous IRP cycle. Can we also expect the 2020 LSE's individual IRP filings to be due August 1, similar to the last cycle's schedule	Staff is not recommending changes to the next LSE IRP filing deadline at this time. LSEs should continue to assume that May 1, 2020, will be the filing deadline.
Southern California Edison (Kathy Wong)	6/21/2019	On slide 91, the third bullet on the page is seeking suggestions for the issue of "new transmission to increase EO capability alone." SCE believes all new transmission would bring some Full Capacity Deliverability Status (FCDS) and Energy Only (EO) capacity value rather than exclusively EO, so SCE does not understand the premise of the question. We would appreciate it if you could help clarify.	This question supposes that there is some technical limit creating the EO capability that the CAISO provided to CPUC. Rather than spending the full cost for some lumpy transmission upgrade to increase FCDS capability, some parties have questioned whether a much more modest (e.g. smaller) upgrade increases EO capability but not necessarily FCDS capability. This also supposes that there is still some economic value to be gotten from more EO resources in a certain region from RESOLVE's viewpoint.

Union of Concerned Scientists (Mark Specht)	6/18/2019	RESOLVE updates to address GHG accounting discrepancies: Back in August 2018, there was a presentation comparing CAISO 2017 GHG emissions to RESOLVE 2018 emissions. At the end of the August presentation, there were a few potential RESOLVE model upgrades listed. Is the CPUC pursuing any of the upgrades listed below? If this is still TBD and more info will come out later, that's fine – just let me know. a. Include fuel consumption when starting CCGTs and peakers b. Impose additional operational constraints on resources providing reserves, potentially resulting in increased peaker utilization c. Add specified coal imports in near-term d. Model part of the CHP fleet as dispatchable and update installed capacity	Staff worked with E3 extensively to better align inputs between RESOLVE and SERVM to mitigate these discrepancies. Near-term specified coal imports into California (mostly to Pasadena and LADWP) are now included in both models. Fuel consumption when starting has been included for thermal resources. Further modeling enhancements may be pursued during the SERVM<>RESOLVE model comparison exercise.
Union of Concerned Scientists (Mark Specht)	6/18/2019	VO&M costs: On slide 23 of yesterday's presentation, there is a list of costs that are included/excluded from VO&M costs. Are the costs that are excluded from VO&M values incorporated into the RESOLVE model in any other place (e.g. fixed O&M costs)? Just starting to wonder if we're systematically underestimating the costs of gas generation – but maybe renewables also have major maintenance costs that aren't included in RESOLVE modeling…	Operations and maintenance costs that do not vary by the output of the plant are included in fixed O&M (FOM) costs. E3 compiled FOM estimates for thermal generation from NREL ATB and a number of different recent utility IRP filings. NREL's FOM costs include: • Insurance, taxes, land lease payments, and other fixed costs • Present value and annualized large component replacement costs over technical life • Scheduled and unscheduled maintenance of power plants, transformers, and other components over the technical lifetime of the plant Renewable FOM costs are also included in the pro forma and input into RESOLVE.