IRP Modeling Advisory Group

Office Hours #1: 10/3/2017

Background

During the month of October, Energy Division staff will host one 90 minute "Office Hours" webinar each Tuesday from 1:00 pm to 2:30 pm to address technical questions from parties related to RESOLVE and/or the staff proposal "Production Cost Modeling Process to Review Integrated Resource Plan Portfolios." During the webinar, staff and technical consultants will provide verbal responses to questions submitted in writing by 4:30 pm on the Friday preceding the webinar. Following each question or topic, parties will have an opportunity to pose additional clarifying questions. In general, staff does not anticipate preparing presentation material, but may do so on occasion. Any materials prepared, as well as audio recordings of each webinar, will be available from the IRP Events and Materials page. The expectations and ground rules documented in the Modeling Advisory Group charter apply.

For more information, please contact Patrick Young at Patrick.Young@cpuc.ca.gov or (415) 703-5357 or Forest Kaser at Forest.Kaser@cpuc.ca.gov or (415) 703-1445.

Questions Submitted

PG&E

Clarifying/Conceptual

1. **GHG prices vs. targets**: if you take a GHG-binding case (such as 42 MMT), use the GHG shadow price outputs as GHG price inputs in another case that removes the GHG constraint, will that other case show the same resulting portfolios as the GHG-binding case? If it does not, why is this? For instance, we ran a case (no GHG cap) using the resulting 2030 $150/MMT abatement cost from the 42 MMT case. The result was a GHG emission of 43 MMT at a significantly higher system cost and a higher renewable build. The two should be roughly commensurate, but this doesn't seem to be the case.

2. **Integration costs**: how are "renewable integration costs" incorporated into the model's resource selection decision? It seems that variable integration costs (marginal increases in reserve requirements) are not incorporated in the resource selection decision, since the reserve requirements are exogenous and not impacted by the resources selected. It also seems that fixed integration costs (such as those captured in the interim RICA) are not included because it is assumed that renewable "pre-curtailment" will limit the marginal need for any additional FlexRA procurement, hence there is no marginal FlexRA premium in the model. Can you please clarify?

3. **RPS Bank**: Could you describe the details of the RPS bank optimization? Looking at the "99mmt_Ref_20170630" case, the outputs ("Portfolio Analytics" row 490) show the spent bank, but do not show the bank growth or cumulative bank size. Does RESOLVE track the cumulative system-level bank size when considering how much bank to apply vs. new procurement for a given RPS target? Running higher RPS scenarios showed negative values for "RPS Spent Bank", presumably these are bank additions rather than bank usage. Please confirm how the model optimizes the RPS bank and how to interpret the results. Also, by default the "Historical Bank – up to 2016 (GWh)" input is 0… is RESOLVE not currently considering any bank built in CP1 or CP2?

4. **End effects:** Can we get more detailed information on the end effects? For how many years after the last year in the study are they calculated and how? They don't seem to be making a difference in some model runs we've done, i.e. we've increased/decreased some operating cost parameters after the last year in the study and get exactly the same results in both cases; if end effects were included, it seems these would have been different.

5. **CHP:** In the LOADS_Forecast tab, it seems that CHP is being subtracted from gross load to get to managed load. But CHP resources are modeled as a must-run resource in the CONV_OpChar tab and included as part of the energy balance. Why is load reduced by CHP generation? It seems like RESOLVE is both reducing load and increasing supply; it should be one or the other.

Technical/Troubleshooting

6. **OOS wind as candidate resource**: when changing the "Out-of-state resource screen" from "Existing Tx Only" to "Existing & New Tx", RESOLVE spits out the following error: "RuntimeError: Failed to set value for param=shape, index=('SW_Ext_Tx_wind', 28, 17), value = 0.88256174502." However, the 0.88… value seems like a valid input. How can we enable RESOLVE to run OOS wind as a candidate resource? Many stakeholders were interested to run these cases.

7. **Running additional years**: some configurations of additional years work (e.g. running every 2 years through 2030, instead of 4) but some do not (running every year or running years after 2030). Can you provide guidance on what configurations are feasible? Is it possible to run RESOLVE through 2050 using the public version of the model?

8. **Error:** An error of "Presolved model was optimal, full model needs cleaning up." What does this mean?

<u>**Nancy Rader, CalWEA**</u>

1. Can you point us to where we would find the CREZ and cost information on the selected resources (specifically, the 1,145 MW of wind in the 42 MMT default case)? We don't see it in the Inputs/Outputs Summary Table.

2. Following up on my question about BTM and NEM, can you confirm that the assumed cost of BTM PV was the estimated installation cost, which does not include the ratepayer impact of

NEM? If so, the ratepayer impact would not be reflected in the $715 million savings figure from the low-BTM sensitivity (default case), correct?

In reference to two case-groups that were run:

The "early_ooswind" cases, which force-in the high capacity factor OOS wind with new transmission in 2018 such that it captures the full PTC

3. Where is this result shown in the Proposed RSP slides (which presumably show the added cost)? And is all OOS wind available to this early case (including connector lines like SunZia + firm transmission on existing lines), or does it reflect 3,000 MW along with two new 500kV lines to deliver directly to California (as with the initial OOS case study run)?

The "unconstrained" cases, which do not force in the high capacity factor OOS wind, but make it available for selection. This case adds 600 MW, for a total of 1,747 MW.

4. Does this add to the 1,145 in-state wind, or supplant some or all of that? If it adds to and does not supplant in-state wind, why would that be, given the much higher capacity factors out of state (given that the in-state wind is generally not in the already-developed CREZs, or is it)?

<u>Pushkar Wagle, BAMx</u>

As I have indicated before, I'm trying to better understand the drivers (and interplay among them) that procures the renewable resources in 2018 instead of in 2026 (wind) and in 2022 instead of 2030 (solar) to take advantage of the expiring tax credits. If I understand correctly, the ***No Tax Credits Sensitivity*** case does capture this scenario as it assumes no PTC, but 10% ITC for solar PV. The PV over multiple years of the difference between the reference case and no tax credit sensitivity seems to be as high as $2.4B as shown in the table blow.

Present Value Portfolio Metrics	Unit	42mmt_Ref_20170831	42mmt_Ref_no_taxcredits_20170831	Diff
PV Revenue Requirement	*$MM*	$672,666	$675,068	$2,403
PV Total Resource Cost	*$MM*	$744,802	$747,205	$2,403
Levelized Revenue Requirement	*$MM*	$40,033	$40,176	$143
Levelized Total Resource Cost	*$MM*	$44,326	$44,469	$143
Levelized Average Rate	*cts/kWh*	19.9	20.0	0.1

I extracted and compared the incremental fixed cost of the new resource build in these two cases. I've summarized it in the table below for the two new representative wind and solar resources. For example, the Riverside_East_Palm_Springs_Solar built in 2022 (with the full ITC) has an incremental fixed cost of $136/kW (unadjusted for the discount factor), whereas the same resource built with reduced ITC cost $174/KW when it is built in 2030.

new_resource	technology	42mmt_Ref		42mmt_Ref_no_taxcredits	
		Year	incremental_fixed_cost ($/kW)	Year	incremental_fixed_cost ($/kW)
Central_Valley_North_Los_Banos_Wind	Wind	2018	$155	2026	$210
Riverside_East_Palm_Springs_Solar	solar	2022	$136	2030	$174

I'm aware that it may not be easy to provide a breakdown of the impact of drivers including the discount rate (capturing time value of money), delta between the renewable resources cost/price with and w/o tax incentives and the value of the energy displaced by the near-term procurement of solar, etc. If we purely look at the first twenty-year period of 2018-2037 period, the time value of money should dominate the tax incentives purely considering the PV of incremental fixed costs as the solar resources under the no tax credit case are procured only in 2030. But then probably the near-term net solar cost (cost of additional solar minus value of avoided energy) plays a large enough role in shifting the balance. Any insight that you could provide in this regard would be helpful for us in submitting more informed comments.

ORA

Allowances are an artificial cost paid by LSEs, and the revenue from those transactions (at least those from the allowances CARB freely allocates to Utilities) are returned to ratepayers in one form or another. So depending on your system boundaries, this may or may not be an actual cost. Only looking at LSEs (and excluding ratepayers), allowances are a real cost of emissions (hence allowances being excluded from RESOLVE's GHG abatement shadow price). Looking at the broader California (or the CAISO portion thereof), ratepayers are included in the system boundaries, so allowance costs and proceeds never leave the system (hence the actual GHG abatement shadow price, which is greater than RESOLVE's by the allowance price).

During the BTM PV session of yesterday's workshop, you said that the TRC includes costs paid by Utilities and ratepayers, but not costs shifted between the two.

1. But isn't the cost of allowances shifted between the two? Is the cost of allowances included in the TRC?

2. *RESOLVE counts allowances as a cost, but with the GHG Planning Price, we are asking LSEs not to include allowance costs in the operating cost of GHG-emitting facilities. Is this a problem?*

3. If allowances were removed from RESOLVE, how would you expect it to change the resulting resource mix?

Additional Questions from ORA

1. *Re: slide 63, Proposed Reference System Model] Could you please go into more detail on how you expect the GHG Planning Price to be used?*

2. [Re: slide 64, Proposed Reference System Model] The shadow price shown here does not reflect the cost of emission reductions accomplished through policies other than a GHG emissions constraint. Is it possible to see the shadow price of the RPS constraint or any other GHG-reducing policies?

3. *Please justify choosing the 42 mmt case rather than the default case. According to CARB's scoping plan, the default case falls within the proposed emission range for the electric sector. What analysis has shown that it will not be enough to meet 40% GHG reductions state-wide? Ideally, I would like to see an assessment that shows that the marginal abatement cost of bringing the electric sector down to 42 mmt is lower than the marginal abatement cost for any other sector of the economy, but unfortunately, this is not feasible…*

Angela Tanghetti, CEC

1. *PCM Model question - is this the correct forum to pose the question about using SERVM simulation results to calculate PRM?*

2. PCM Model question - Is there a way to derive peak load, available capacity of non-wind and -solar resources as well as imports in order to calculate PRM with SERVM results?

3. PCM Model and RESOLVE question – How is fuel use by CHP units separated between electric generation and fuel use for processes or the host? This has implications for the GHG calculation. It appears RESOLVE accounts for the energy portion provided to the bulk power system but not clear what heat rate is used to calculate the fuel use.

4. RESOLVE question - Are out of state candidate renewable resources counted as imports? In the documentation for RESOLVE it says all imports are given the ARB unspecified GHG emission factor.

Diamond Generating Corporation

1. What are the on and off peak energy price assumptions?

2. What are the capacity price assumptions (kw-month)?

3. What is the Return on Equity assumption for the following existing generation:

    a. Natural Gas CCGT
    b. Natural Gas Single Cycle Peaker
    c. Solar
    d. Wind
    e. geothermal

4. What is the Return on Equity assumption for the following types of new builds:

    a. Natural Gas CCGT
    b. Natural Gas Peaker
    c. In-state Wind
    d. Out-of-state wind
    e. Solar
    f. LI batteries
    g. PHS

AWEA, California Caucus (ACC)

1. **PTC**: Are new utility-scale wind contracts that come online before 2022 assumed to be PTC-eligible in the RESOLVE model?

2. **PTC:** Does RESOLVE account for the different levels of the PTC in 2020 vs. 2021 and so on? (e.g. projects online in 2020 can be eligible for the full value of the PTC, 2021 projects can be eligible for 80% of the PTC, and so on). (please see Timeframe discussion in 6/28 ACC IRP cmts, p.8:http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M195/K829/195829307.PDF)

3. ***GHG Scenarios:*** *Has the CPUC considered modeling an intermediate GHG reduction level between a 42 MMT and 30 MMT--both to test the ability of the electric sector to even further decarbonize and also as a "hedge" in the event that other technologies do not perform as assumed?*

4. **Curtailment:** Do you have the capability in the RESOLVE model to break out which renewable resources are curtailed in the different scenarios. More specifically, are you able to distinguish between the level of solar curtailment vs wind curtailment?

5. ***Export limit:*** *Have you conferred with the CAISO on the net export limit and under what circumstances to you envision 5000 MW of simultaneous flow?*

6. **Recontracting:** Have you considered running a scenario with a 50% recontracting rate to capture some potential for repowering or additional market for new resources?

7. **RESOLVE 37 Day Period:** Has the CPUC determined whether the 37 day modeling period is representative of expected annual emissions – i.e., under the various GHG scenarios (30 MMT, 42 MMT, etc.)? In other words, do the emissions in the 37 days for a particular emitting facility reflect what the facility's annual emissions will be?

8. **Existing Gas Fleet Assumptions:** Does RESOLVE Presume that existing gas generation remains available irrespective of whether it has a contract? Is this assumption based on an assumed lifetime for the facility (e.g., 30 years) or is the assumption in any way based on-peak and off peak energy and capacity prices?

9. ***RESOLVE Timing:*** *Will E3/Commission consider any changes to inputs/assumptions at this point?*

SCE

1. In the worksheet REN_Supply_Curve, there are 63 unique values for RESOLVE_Resource_Name. However in the solution, Results_Viewer >> Portfolio_Analytics >> Selected Resources by Location, there are only 42 RESOLVE_Resource_Name(s) listed. Why were 21 options excluded from the optimization? Does the exclusion take place on the worksheet REN_Candidate – table Renewable Potential by RESOLVE zone and year?

2. In the Dashboard, the setting "Existing & New Tx" always causes the optimization to exit. Furthermore, we see that the OOS_Wind sensitivities are achieved by forcing New_Mexico_Wind and Wyoming_Wind into the model, rather than making them available for endogenous choice. Why was the sensitivity done in this way and can the model be enabled to evaluate Out of State renewables on its own? How were the transmission adders on REN_Tx_Costs >> Out-of-State Renewable Transmission Cost Adders calculated?

3. In the Dashboard Simulation Years table, setting all years between 2018 to 2030 equal to 1 causes the optimization to exit. Why isn't the model computed on an annual basis? How was that decision made and can it be repaired?

4. How does RESOLVE use the information about 1280 renewable projects to combine into only 42 RESOLVE_Resource_Names? Are the estimated project-level costs listed in REN_Supply_Curve >> column indices AR-KC used anywhere in the simulation?

5. How were the ELCC surface parameters estimated and what was the data?

6. In Results Viewer >> Portfolio Analytics >> Energy Balance section, we see that something called "Schedule Curtailment" can contribute to meeting the energy balance. What is scheduled curtailment and how can it meet load? What is the curtailment price applied?