From:	Koehler,Birgit G (BPA) - PG-5
Sent:	Wednesday, May 18, 2022 1:47 PM
To:	James,Eve A L (BPA) - PG-5
Cc:	Leary,Jill C (BPA) - LN-7; Godwin,Mary E (BPA) - LN-7
Subject:	22.5.16_DOE-Lab Review Comments on E3 Analysis, bk
Attachments:	22.5.16_DOE-Lab Review Comments on E3 Analysis, bk.docx

Confidential and Privileged, Attorney-Client Communication, Do Not Release under FOIA

Eve,
Here are my notes, including from our discussion just now, to supplement the notes you took.

Mary and Jill,
I'm writing a separate email to a slightly larger group that will give you more info. If you haven't yet read the DOE review, but plan to, you might as well look at this version with some comments from us.

Birgit

Follow-up Thoughts

(b)(5)

[redacted]

===

DOE-National Lab Comments on Draft E3 Study:

"BPA Lower Snake River Dams Project Draft Final Results"

DOE commends BPA for engaging E3 in this study and appreciates the accelerated schedule within which it was conducted. A technical review of the study was conducted by DOE and National Lab staff. Following are consolidated comments.

Note that some of this feedback, if addressed, would require substantive new work, and time. This is especially true for our comments on the scenarios, and on ELCC treatment and assumptions. We encourage discussions in the near term to determine whether and how to address those comments.

LARGER COMMENTS

Scenarios

- Several of the Modeled Scenarios Appear Implausible: We question the inclusion of the two "Limited Technology" scenarios, as well as the "2024 LSR Replacement" scenario. On the latter, even with an extremely accelerated process that leads to dam removal, would a 2024 removal-and-replacement scenario be feasible? If not, we recommend revising this scenario to include a more realistic yet still accelerated assumption—2027 replacement, or whatever makes sense. On the former, the two "Limited Technology" cases not only eliminate or severely restrict combustion technologies, but they also offer the model no other realistic 'long duration' storage options. Yet several options exist, most obviously producing electricity still with hydrogen but using fuel cells as the conversion mechanism. Alternatively, a wide variety of emerging longer-duration storage technologies could prove viable. The result are two scenarios that are implausible in design, and equally implausible in future likelihood. The scenarios should be eliminated or revised. If BPA-E3 feel that these scenarios, as designed, offer some value as 'bogeys', at a minimum we recommend that they be presented solely as "what if" scenarios in the "with LSR" section of the presentation. These scenarios should not be used to estimate replacement costs of LSR removal (slides 39 on).
- A Tax Credit Extension Scenario Should Be Considered: Based on the appendix slides, the analysis appears to assume that existing tax credits phase out—as per current statute. Alternatively, it is also plausible that existing tax credits will be extended, and that new ones may be created. We recommend at least one scenario that assumes extended and possibly expanded tax credit availability. Even if BPA is unable to directly access such credits through ownership, their availability for private entities should reduce the effective cost of LSR replacement. Running a scenario or side analysis to investigate these possible cost-reducing effects of longer-term clean energy tax credits would usefully supplement the current analysis.

Input Assumptions

- ELCC Values and Influence on Overall Results Deserve Attention: The capacity credit assumptions and results are likely extremely important in estimating the costs of having to replace the LSR dams' grid benefits. One of the footnotes states "…a significant portion of the costs is capacity costs to replace the dams' RA capacity contributions". We have a few comments and concerns:
    - Cost Reporting: Can the fraction of the 'cost of LSR replacement' that comes from capacity needs be calculated? Based on the low raw LCOE costs of wind and solar, it seems logical that the capacity credit costs might make up half or even more of the total cost. If true, then all capacity-credit related assumptions and results are extremely important.
    - Capacity Credit of LSR Dams Should be Investigated, and Possibly Revised: The analysis assumes that the LSR dams have, in effect, a 65% ELCC and so a resource adequacy value of 2.2 GW. Since the estimated replacement costs is driven in large measure by resource adequacy, confidence is needed on the capacity credit assigned to the LSR dams. As well, given the importance of resource adequacy to the analysis, it is important that ELCC estimates employed for the LSR dams use similar methods to those used for other resources. Some advocates in the Northwest have presented data and analysis suggesting that a much lower capacity credit is warranted, maybe half that assumed in the E3 study, see: Addressing-the-LSR-Peaking-Capacity.pdf (nwenergy.org). DOE has not independently assessed the linked paper, or the capacity credit of the Lower Snake River dams. But given the critical nature of this single input parameter, we recommend that E3 evaluate the linked paper and LSR output data during periods of system stress to either validate or revise the

assumed 65% capacity credit. If a proper ELCC-type study for these facilities has not been conducted, then a review of historical output during periods of peak historical winter and summer (net) load could be used as an approximation. Under the decarbonization scenarios, a focus on the winter period or maybe the early fall (lower PV, so potentially high net load) may be relevant. Overall, more work is needed to validate these assumptions.

  - Storage ELCC: The capacity credit of storage seems to be substantially lower than what has been calculated in other regions, particularly for the 12-hr storage duration, after the first few GW of storage is deployed. We did not review the referenced study, but details on how these assumptions were created would be important within this slide deck. Information that would be helpful would include: (1) What does the winter peak look like? (time of day, duration, etc.); (2) What do resource profiles look like on that day, such that a combination of wind, solar, and 12-hour storage cannot contribute significantly? (3) Are interactions between wind, solar, and storage considered at all? (4) Are the scenarios in the referenced study similar enough to the scenarios in the LSR study to apply the same parameterization? Finally, are such low ELCC values for storage, even 12-hour storage, consistent with the 65% ELCC assumption made for the LSR dams?
  - ELCC Implementation--Exogenous or Endogenous: It appears that ELCC values are exogenous to the scenarios, but that fails to capture the impact of load—both load shape and load level—in determining ELCC. Can E3 provide more information on how these values are implemented? As well, the ELCC values on slide 22 depict ELCC by capacity deployed. When operationalized in the Resolve model, are these ELCC values linked to capacity amounts, or percent of energy? The deep decarbonization cases represent larger power systems, with higher amounts of load. One would anticipate, in such a case, that the ELCCs would drop more slowly relative to deployed GW--does Resolve appropriately capture that?

- Technologies Considered: (1) Why are dedicated H2 plants excluded in most of the scenarios while dual fuel is available—what is the rationale based on technology maturity or resource availability? (2) How can the CCS and dual fuel techs be used under the 0 MMT by 2045 scenarios without CDR offset? (3) The table shows 90-100% capture rate for CCS, but can 100% truly be achieved? (4) Why is offshore wind considered alongside CCS and Nuclear-SMR? Floating offshore wind is less mature than fixed-bottom, to be sure, but should at least be considered as a possible baseline technology.
- Hydrogen Cost Appears Overly Conservative: The assumed cost of delivered hydrogen declines to ~$40/mmBTU by 2045. This is a conservative assumption. Current biodiesel is $20-30/MMBtu. Even with conservative H2, the lack of availability of other renewable/biomass fuels results in high replacement costs in these scenarios. The cost of hydrogen-CCGTs in the model may be largely driven by CapEx, so perhaps this conservatism does not greatly impact modeled results. Nonetheless, given the importance of hydrogen in the analysis, we recommend a review of this assumption and possible development of a less conservative input assumption.
- Additional Resolve Inputs: Why are 90% and 100% capture rate CCS so similar in $/kW-yr costs on slide 65? Why are H2 peakers and combined-cycle units almost identical in cost?
- Transmission Representation: Are the system-wide benefits of transmission (assumed to be needed for out of region wind and solar) considered? Is there any assumed resource adequacy contribution from this transmission, which could be provided from external “clean firm” resources? Also unclear more broadly how opportunity for imports and exports of all electricity services (energy, capacity, ancillary services) are being treated.

Presentation

- The Cost Reporting on Slides 39-42 Should be Expanded: Cost results can usefully be presented in numerous ways, depending on context. Given varying contexts, we recommend presenting these costs in numerous ways. The NPV results may be relevant if Congressional appropriations were to be used to cover replacement costs. The percentage increase in BPA Tier 1 rates is relevant if BPA's Tier 1 customers were to fully pick up the tab. We recommend presenting the results in at least one additional way: as a percentage increase in retail electricity rates among all customers in the NW. As well, then presenting the annual results on slide 40, we presume these are presented in real terms, and are not discounted: please clarify in slide as appropriate.

External Review

- External Review Process: Does BPA anticipate issuing the final report without an opportunity for external stakeholder review of a draft? It may be productive to discuss the possible value, advantages, and disadvantages of offering regional stakeholders an opportunity to review and comment on the draft—recognizing that conducting such a review would entail time and budget.

ADDITIONAL (SMALLER) COMMENTS

- Focus on the Core NW Region: The study is focused on a region of the Northwest that includes Washington, Oregon, and portions of Idaho and Montana. Yet the policy review early in the PPT includes California and lacks any discussion of the policy context in Montana and Idaho. At a minimum, this seemingly incongruous treatment deserves explanation.
- Slide 6: "Decarbonization is creating a current and deepening need for capacity." This isn't strictly true. There's always a need for firm capacity. But if that capacity is emitting and there exists a requirement to get to zero or very low carbon, then just like energy services, capacity services need to be replaced. Statement should be clarified for accuracy.
- Slides 9-10: For clarity, might wish to note that the company specific data here come from an E3 review of the latest vintage of each company's IRP. This is implied, but at least one reviewer was confused as to the source of those data.
- Slide 11: May want to add a little bit of additional information on *why* the power cuts were made, based on CAISO's report on these outages. http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf.
- Slide 20-21: "RESOLVE resource adequacy constraint requires capacity to meet peak demand + a 16% planning reserve margin". Why 16%, and why is that different from 15% shown on slide 20?
- Slide 25: (1) "Reaching a zero emissions electric system with high electrification and reasonable levels of renewable additions requires new technologies such as hydrogen combustion turbines or nuclear SMRs." This is then followed by sub-bullets focused on SMR and H2. Those sub-bullets make it sound like one strictly requires EITHER SMR or H2, but there may be other longer-duration storage options or flexibility options such as fossil-CCS that could fill those needs as well. Recommend being less technology prescriptive, especially since only a subset of options are modeled, and focusing more on the services needed, with examples of SMR and H2 technologies. As well, are new technologies really "required" or just "cost-effective" if they exist. (2) It is not decarbonization that

drives peak needs, it's electrification when paired with the CO2 constraint. (3) "Additional renewables backed by dispatchable hydrogen plants are needed". Renewable energy technologies are not "backed up" by hydrogen, any more than nuclear plants are backed up by peakers, or peakers backed up by baseload. They provide different services.

- Slide 36: This slide or others ideally would show load and how storage is being charged/discharged to help meet load. In addition, as per an earlier comment, we suggest adding slides showing why storage (and VRE) resources have such low ELCCs.
- Slide 49: "Inverter based generation cannot inherently provide inertia, but may still be able to provide fast frequency response via grid forming inverters." Two comments: (1) Inverters do not need to be "grid-forming" to provide FFR, so should alter text accordingly. (2) A lot of research is happening in this space. What is missed is the inertia requirements of the grid in various forecasted years and how any deficit would be mitigated via technology.
- Slide 50: "Large hydro is historically a major provider of black start services when required." This would be better stated as declared hydro. Many facilities have the capability but don't offer it since it puts them within specific requirements of black start units.