OREGON SOLAR + STORAGE INDUSTRIES ASSOCIATION

Oregon Public Utility Commission
201 High Street SE, Suite 100
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August 2, 2021

RE: Docket No. UM 2011, comments on Staff proposal

Dear Chair Decker, Commissioner Tawney and Commissioner Thompson,

OSSIA appreciates the opportunity to provide input on Staff's "Value of Capacity" straw proposal presented at the July 15 UM 2011 workshop. OSSIA offers the following thoughts:

1. Use no more than a three-year ramp period

Staff proposes a three-year ramp for PAC and PGE, but a ten-year ramp for IPC. At the workshop in July, Staff explained that the reason for this change is that IPC has not procured new resources in ten years. OSSIA does not agree that a ten-year ramp is appropriate. As noted in OSSIA's April 2021 reply comments in this docket, IPC's 2019 IRP showed future capacity need within ten years, and also past capacity procurement within ten years. IPC's preferred resource plan adds 120 MW of solar capacity in 2022, 500 MW of transmission capacity in 2026, storage capacity in 2030, and gas-fired capacity in 2031. Scenarios without the B2H transmission project result in additional need. Appendix C of the IPC IRP showed IPC has acquired wind and solar capacity within the last decade. Further, Idaho power recently issued a notice of intent in anticipation of issuing multiple RFPs including for an 80 MW capacity need as early as Summer 2023 and peak deficits that grow to approximately 400 MW by Summer 2025.[1] Meeting clean energy goals, retiring existing coal plants, and customer electrification will require adding new clean capacity resources. The situation faced by IPC is no different than for PAC and PGE in this regard, and it makes no sense to adopt a significantly different ramp period.

2. Ramp up from a Nonzero Resource Adequacy (RA) Capacity Value

Even when utilities have sufficient capacity, its value is not zero. Resource Adequacy (RA) programs indicate the value of capacity.[2] As pointed out in our April comments, existing resources must recover ongoing fixed O&M costs. Wholesale energy markets are not sufficient for generators to recover all fixed costs. Therefore, if a three-year ramp period is utilized, it should not transition from 0% value in year 1, 33% value in year 2, 67% value in year 3, to 100% value in year 4, but rather the transition to full capacity value should occur over three years, starting from the value of RA capacity in the first year (e.g. RA capacity value in year 1, 33% x full capacity value + 67% RA value in year 2, 67% x full capacity value + 33% RA value in year 3, and 100% full capacity value in

[1] See Idaho Power, Notice of Intent 2021 All-Source Request for Proposals, at https://docs.idahopower.com/pdfs/AboutUs/businessToBusiness/2021-notice-of-intent.pdf.

[2] For example, Table 6 of California's 2019 annual RA report, at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf, shows an average RA value of $3.46 per kW-month.

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year 4). Further, while the Staff proposal has been referred to as a "3-year" ramp, the zero value in year 1 actually means it is ramping up over four years rather than three resulting int the full capacity value is not being reflected until year 4. Therefore, the zero value in year 1 should be eliminated so the cull capacity value is reflected in year 3.

3. Consider eliminating the ramp period altogether

Ramp periods will inherently undervalue new capacity that competes with new utility-owned capacity. If a resource is paid over a 20-year period that includes the ramp period, for example, it would receive only 73% (ten-year ramp) to 90% (three-year ramp) of the 100% cost-recovery value a utility-owned resource would receive. There is no reason for such a fundamental inequity.

Year	10-year	3-year
1	-	-
2	0.10	0.33
3	0.20	0.67
4	0.30	1.00
5	0.40	1.00
6	0.50	1.00
7	0.60	1.00
8	0.70	1.00
9	0.80	1.00
10	0.90	1.00
11	1.00	1.00
12	1.00	1.00
13	1.00	1.00
14	1.00	1.00
15	1.00	1.00
16	1.00	1.00
17	1.00	1.00
18	1.00	1.00
19	1.00	1.00
20	1.00	1.00
Average	0.73	0.90

In addition, it should be noted that, while Staff stated in the July workshop that it would rather just speak of a "ramp period" and discard the labels of resource sufficiency and deficiency, these concepts relate to capacity value. When a utility has more resources than it needs to meet its peak load (plus planning reserve margin), the economic value of capacity may be less than the average cost of new capacity. When the utility has a need for new capacity, the economic value may be greater than the cost of new capacity. The resource balance year concept embedded in the ramp proposal appears to be that capacity will only ever have value that is less (during the ramp period) or equal (after the ramp period) to the average cost of new capacity. That approach fails to recognize that scarcity conditions, and need for new capacity, may result in capacity value that is, at times, above the cost of new capacity. Therefore, we would strongly encourage Staff to consider eliminating the ramp period. Otherwise, new non-utility capacity resources with online dates within four years, or existing resources paid under this structure (e.g. RVOS for community solar) would see reduced capacity values that fail to recognize the need for capacity.

It is worth emphasizing that excess capacity is a natural feature of a well-planned utility system. Scarcity may occur, either if planning fails or there are unexpected circumstances, but in general we cannot rely on markets to determine capacity entry and exit, because the cost of outages and need for reliability at all times is so important. Thus, the idea that the energy market may be able to signal capacity need is wrong. Capacity generally will always need to be acquired ahead of need, in order to ensure reliable service. This does not "break the link" between need and value, as Staff has asserted in the past. In fact, as pointed out by the economist Alfred Kahn, it is probably best to use the long-term incremental cost as the basis for capacity value. The following provides a quote from that work, which we think is relevant:

"As J.M. Clark has often pointed out, excess capacity is the typical condition of modern industry; and we would probably want this to be the case in public utilities, which we intend to insist be perpetually in a position to supply whatever demand are placed upon them. In these circumstances, firms could far more often be operating at the point where SRMC [short-run marginal cost] is less than ATC [average total cost] than the reverse, and if they based their prices exclusively on the former, they would have to find some other means of making up the difference. Partly for this reason, and partly because of the infeasibility of permitting prices to fluctuate widely along the SRMC function, depending on the immediate relation of demand to capacity, the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC, estimated for a single additional sale. This long-run incremental cost (which we shall loosely refer to as long-run marginal cost as well) would be based on (1) the average incremental variable costs of those added sales and (2) estimated additional capital costs per unit, for the additional capacity that will have to be constructed if sales at that price are expected to continue over time or to grow."[3]

Thus, a ramp methodology that permits capacity value to fluctuate in only one direction (i.e. only downward, with low value during capacity "sufficiency" periods, but not high value during "deficiency" periods) is not reasonable or equitable. New and existing resources make up the gap between energy market revenues and total cost through capacity payments (including RA value), and, as we have pointed out in prior comments, wholesale energy markets such as the CAISO day-ahead market have never produced sufficient revenues to cover the cost of new capacity.

4. Use Solar plus Battery storage for the proxy resource

Staff has proposed that the proxy capacity resource be based on the avoided cost of procuring capacity from the least-cost resource that is reasonably available in Oregon. We recommend that proxy resource should be assumed to be utility-scale battery storage, which may be assumed to be charged either from solar PV capacity as a hybrid resource, or from off-peak wholesale energy

[33] Attachment N: Kahn, Alfred E. (1989 Edition) The Principles of Regulation: Principles and Institutions, Part I, pages 84-85.

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purchases as a stand-alone battery storage resource. At some point it may be necessary to augment the battery cost with the cost of an underlying generation capacity resource to charge the battery, such as solar PV; however, in the near future we expect there will continue to be ample off-peak energy supply available for charging battery capacity.

Clean energy goals mean that gas-fired generation is no longer the reasonable new resource to build. New capacity should be assumed to be something that would actually be added to the system. Therefore, we recommend the proxy resource capacity cost should be based on the annualized cost of utility-scale four-hour battery storage, less the expected energy market rents (levelized to match the battery storage life) that such a resource can expect to earn in the wholesale energy market (e.g. the difference between on-peak and off-peak wholesale market prices, adjusted for the impact of storage losses). This would reflect the annual "above market" cost of battery capacity.
As an example, SEIA has recommended, in the Southern California Edison 2020 general rate case, that SCE's marginal generation capacity cost should be the annualized battery storage costs, less energy market rents, of $138 per kW-year (i.e. $206 per kW-year battery cost, less $68 per kW-year levelized energy rents).[4]

5. Provide hourly ELCC information rather than single annual values

Staff describes how the cost of capacity would be multiplied by annual ELCC values. We recommend that rather than making a single adjustment each year to the proxy capacity value in this fashion, third-party generation resources should also be given the underlying data that leads to the annual ELCC value. For example, if ELCC value for a given resource is the product of an 8760 hour allocation of capacity value (i.e. the distribution of capacity value to hours of the year) and the expected 8760 hour generation (i.e. hourly capacity factors) of the generation resource, rather than using a single annual value, a resource should be able to see the hourly values underlying the ELCC calculation, so that, if they are able to optimize their output (e.g. such as a hybrid solar plus battery resource altering its generation profile so as to maximize its hourly capacity factor during the hours of the year that are most valuable to the utility), the annual ELCC value can be improved.
An example of this problem is the RVOS model, which in addition to hourly LOLPs, includes a target annual ELCC value. No matter what solar profile is entered into that model, the annual ELCC value is used, given the model includes an adjustment factor that essentially over-rides the value that is determined as the sum-product of the hourly solar profile and the hourly LOLP (allocation of capacity value to hours in the year).

If there are hours of the year that have the most capacity value for given locations, that information should be made available for the purpose of determining capacity value. In particular, opaque single annual values that cannot be understood, or improved upon with changes to output or other circumstances, should be avoided. Staff has mentioned that it expects solar ELCCs will always be positive. On the other hand, low, but nevertheless non-zero, annual ELCC values could be unreasonable and unsustainable for new generation. A transparent and flexible methodology will therefore be key to ensure a viable capacity value methodology. Staff should oversee the calculation process to ensure that the ELCC process does not result in single, opaque, and infrequently updated

[4] See the Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association, July 26, 2021, in CPUC Application 20-10-012.

values for various resource types and locations. Even if it is difficult to make the calculations transparent, making the results of the calculations more transparent, by including an 8760 profile of the allocation of capacity value will ensure that ELCCs are not simply a penalty to the value of capacity. Moreover, it would be clear whether the single ELCC value represents an inherent capacity derate, for example if the hourly allocation does not sum to 100% for all the hours in the year (i.e. if there is a built-in presumption that the resource, no matter how its output is shaped/allocated, is worth less than 100% of the full value of capacity). It is also important to recognize that annual ELCCs, and the underlying shape of the hourly capacity value allocation, will change – and may increase – throughout the forecast period, as electrification goals begin to be accomplished and electric loads increase, or as battery storage and other clean energy generation capacity resources continue to be developed. Providing that underlying hourly capacity value shape as part of the ELCC results will be important for achieving a transparent and valuable capacity value methodology outcome from this proceeding that can be put to use with confidence in various applications.

6. Conclusion

In conclusion, we note that Staff's recent straw proposal does not include much elaboration regarding why various party proposals are or are not incorporated into its straw proposal. The Staff's final proposal would benefit from including the Staff's rationale as to why proposals from various parties' comments should be either accepted or rejected. Parties would know they have been heard and would be able to better understand and usefully comment on Staff's reactions to these proposals. In addition, to the extent there are nuances in Staff's straw proposal that are not spelled out or fleshed out, except verbally in workshops, it would be helpful if those issues could be included in writing so that the straw proposal is as comprehensive as possible. Examples of such nuances are: (1) what happens when project online dates are delayed, and are the shortened contract terms or contractual penalties that would result from delay sufficient to allay concern that the ramp period should be shifted? Or, (2) how does the capacity value methodology apply to existing projects *vs.* new projects? Finally, we applaud the inclusion of helpful numerical examples, such as are contained in the straw proposal, as they provide concrete examples of how the methodology is expected to work. We recommend expanding upon those examples, to show how the net cost of a specific proxy resource would be calculated, how an ELCC annual forecast calculation would work and apply for a specific resource (with 8760 examples), and how the values would be combined with a potential ramp period to result in actual capacity payments to the resource made. Even if certain aspects of such calculations are deemed to be out of the scope of this proceeding (e.g. whether or not to levelized capacity payments), it would be helpful to understand the complete calculations that are being proposed. This greater detail will also help parties to identify the dividing line between issues to be decided in this proceeding or elsewhere in other proceedings.

Again, we very much appreciate the opportunity to provide input to this important proceeding intended to develop a methodology for the value of capacity.

Sincerely,

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