OREGON SOLAR + STORAGE INDUSTRIES ASSOCIATION

Oregon Public Utility Commission
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April 26, 2021

Re: UM 2011 Comments

Dear Chair Decker, Commissioner Tawney and Commissioner Thompson,

Thank you for the opportunity to continue to provide comments on this important docket. The UM 2011 investigation <u>must</u> include a thorough understanding and clearly articulated recommended mechanisms for determining Capacity Price.

Recent events and reasonably expected future events punctuate the need to examine the serious collateral impacts to ratepayers of interrupted service when evaluating and balancing the utility's obligation to provide for the safe and reliable delivery of electricity to its rate payers. Having adequate capacity in a utility supply system is one part of that analysis. Flat pricing per megawatt hour does not provide the level of resolution necessary to proactively identify deficiency periods nor the price signals to challenge the market to cost effectively fill these needs.

In setting a level of capacity that is prudent, evidence should be taken on the loss of commerce, education, perishables and human life experienced in relation to power outages in our state, region and nation in the past three years. Again, capacity is only one part of the response, but the costs and expenses born by rate payers during loss of load periods significantly exceeds the loss of revenue realized by the utility. While not easy to measure, avoiding a loss of load event avoids costs that should at least be considered and reflected in Capacity Valuation and Pricing.

We commend staff's retention of E3 to provide staff and all stakeholders with third party analytical support in these complex matters and urge staff to further retain this support as well as 3rd party scenario modelling support. OSSIA requests a series of workshops designed to better understand and explore effective Capacity Valuation and Pricing methods. In particular, we recommend that a minimum of four workshops be held on the following topics:

1. Avoided Resource –What is the buildable avoided resource? PGE's Wheatridge Solar plus Storage facility may provide a proxy exemplar of one utility's value of solar, storage and capacity for this workshop to explore.
2. Scarcity – What is the forward curve on expected capacity losses? What is the sensitivity of levels and timing of hydroelectric production to needed capacity? What is the forward

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curve on that sensitivity? What is the existing pipeline for resource development? What tools can be employed to accommodate transparent sharing of this information?

3. Cost to ratepayer of lack of capacity – Conduct a literature and data review of the cost to rate payers incurred by a loss of access to safe, reliable electricity as experienced in Oregon, Texas, California and other areas of our nation in the past three years.
4. Solar resource – Solar energy is a key part of Oregon's carbon free future. Too much effort has been spent trying to prove that Solar 1.0 is not worth much. What are the benefits of Solar 2.0 and Solar 3.0 and are those benefits worth pursuing? Wheatridge solar plus storage is Solar 2.0 and should provide a great classroom study on costs and benefits, and should provide a good platform to discuss if Solar 2.0 can be done even better. This workshop could also review best practices for data collection and use for inputs into ELCC and other methodology of value contributions. Consider using a transparent third-party service to determine best practices and collect the data or solar, Solar 2.0 and further improvements in solar and storage technology inform effective valuation and pricing.

Recent events in Texas underscore the imperative for the PUC to avoid similar events in the Northwest, particularly in the case of resource inadequacy. Given that NW Power Planning does not include low frequency, high consequence events in that scenario modeling, it is extremely important that the PUC focus on quantifying the exposure to the rate payers of extensive loss of load and to provide regulations, market signals and valuation to provide for a safe, reliable grid.

Fortunately, OPUC has the staff, the backing of Executive Order 20 04, access to resources and modern tools necessary to conduct this timely work and OSSIA looks forward to continuing our contributions of constructive input as is enumerated below.

1. Introduction

OSSIA appreciates the opportunity to provide reply comments to parties' March 8, 2021 comments in UM 2011. We focus on the remarks of the joint utilities (Portland General Electric Company, Idaho Power Company, and PacifiCorp).

2. Assumed Sufficiency Period

If staff's proposed three-year sufficiency period is retained, it should only be considered in a PURPA context with the self-build and market-offer capacity compensated on a similar basis. This is also acceptable in the utility IRP space provided that filings are monitored over time to ensure the three-year assumption remains reasonably accurate and is updated over time if necessary.

The Joint Utilities commented that resource sufficiency and deficiency periods are terms that are typically only used in the context of PURPA avoided cost. While the sufficiency/deficiency concept may be used for PURPA avoided cost, we note that it is not limited to PURPA avoided cost calculations. Staff's Opening comments noted that the resource deficiency concept is currently used for PURPA, energy efficiency, and demand response.[1] Further, the Oregon RVOS makes use of this concept as well.[2]

Nevertheless, the Joint Utilities state, in a footnote, that this proceeding should not include proposals that adjust the broader notions of resource sufficiency and deficiency as applied in PURPA avoided cost. We disagree. If the point of this proceeding is to develop an overarching method to value capacity, it should be within the scope of this proceeding to consider whether and how the sufficiency period concept needs updating in any context. For example, OSSIA's opening comments noted that the overall concept of sufficiency/deficiency periods, with reduced pricing during sufficiency years, reduces average capacity value below the average cost of a proxy resource: pricing is below the average cost of the proxy resource during the sufficiency period and just equal to it during the sufficiency period. We think that the method of determining the sufficiency period duration (including the possibility of zero years, or the staff's proposed 3-year assumption) are important issues that should be considered broadly in this proceeding, whether or not they are ultimately carried over to PURPA avoided cost based on determinations in other dockets such as UM 2000.

The Joint Utilities argue that the sufficiency period should not be arbitrary (i.e., all utilities should not be assumed to be deficient beginning four years into the future). We disagree that adoption of a standardized sufficiency period assumption necessarily results in an arbitrary approach that divorces the assumed sufficiency period from any analysis of actual need, such as occurs in IRPs. OSSIA's recommendation, to monitor/analyze IRPs and update the three-year assumption as appropriate, should result in maintaining linkage with IRP analysis of actual future need.

The Joint Utilities appear to be concerned that an assumption of a three-year sufficiency period is not long enough. They also note that actual procurement intervals can vary, such that it is longer and shorter than three years at any point in time. Yet, according to the Joint Utilities, PGE acquired resources in 2010, 2011, 2016, and 2020. In this case, the corresponding 1-year, 5-year, and 4-year intervals between these resource additions averages very close to three years. We do not think that it is important for a methodology to be more granular, so long the 3-year average is accurate. As the Joint Utilities note, there is a tradeoff between complexity and accuracy.

It is more important to be forward-looking for the determination of sufficiency periods (i.e., based on IRP projections) rather than simply to look at procurement over the last decade. In pointing out that PGE's historical acquisitions are not representative of the other two utilities, the

[1] Staff Opening Comments at 5.

[2] For example, the 2019 order on PGE RVOS noted at page 9 the different pricing structures during sufficiency and deficiency years.

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Joint Utilities note that IPC's procurement interval was a decade, between two non-QF resources that came online in 2012 and a solar resource that is expected to come online in 2022. However, IPC's 2019 IRP preferred plan includes the 2022 solar addition (+120 MW from Jackpot Solar in 1 year from now), followed by the 500 MW B2H transmission project in 2026 (4 years later), solar and storage capacity added in 2030 (4 years later), and 300 MW of gas-fired generation capacity added in 2031 (1 year later). Scenarios without B2H transmission result in additional need. It is not reasonable to say IPC does not need capacity for 10 years as of 2021, simply because additional utility-owned capacity was not procured between 2012 and 2022. We also note that Appendix C of the IPC IRP shows that IPC procured QF wind and solar capacity during this interval, so the three-year interval may fit IPC's history as well.

Looking at PGE's 2019 IRP Update[3] shows that PGE predicts a reference-case need of 511 MW in 2025, increasing to 909 MW in 2026. PGE's IRP update indicates (at Table 25) an energy balance deficit starting in 2025 for the reference case. The following table summarizing PGE's reference case additions, from Tables 27-28 of PGE's IRP update, show PGE acquiring generic capacity "fill" resources as early as 2024.

Table 1: PGE 2019 IRP Update Preferred Portfolio Cumulative Capacity Additions (MW)

	2023	2024	2025
Wind	150	150	250
Storage (6-hour)	0	7	7
Capacity Fill	0	71	330
Total	150	228	587

PacifiCorp's 2019 IRP[4] indicates selection of 600 MW battery storage resources (paired with solar) by the end of 2022, and 1,400 MW of stand-alone storage starting 2028.

Thus, the most recent IRPs do not appear to support extending staff's proposed three-year period to a longer period of time. In any case, we expect it will be possible to revisit a fixed or uniform (e.g., three-year) sufficiency period assumption over time as new IRPs are completed, and standardize how that analysis is performed, such that the assumed sufficiency period is forward looking and reasonable accurate.

3. Capacity Value During the Sufficiency Period.

[3] See page 34 of: https://assets.ctfassets.net/416ywc1laqmd/1PO8IYJsHee3RCPYsjbuaL/b80c9d6277e678a845451eb89f4ade2e/2019-IRP-update.pdf

[4] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf at page 9.

The Joint IOUs argue that resources should not be compensated for capacity when a utility is capacity sufficient. We strongly disagree.

First, as we noted in opening comments, the assumption that capacity value will never exceed the cost of proxy resource, for example due to scarcity or during high load conditions, means that the overall value of capacity over all periods (sufficient and deficient) is less than the average cost of the proxy resource. This means that the methodology should recognize when capacity value is both higher than average cost (during times of scarcity when demand is extremely high) or lower (when it may only reflect the going-forward O&M and capital replacement costs of existing plants during the sufficiency period).

Second, wholesale energy markets do not completely capture capacity value. With utilities forced to procure ahead of need, so as to ensure adequate system reliability and generation capacity, wholesale energy markets do not signal the need for additional capacity, other than during short-term extreme price spike events. In general, it means walking a perpetual tightrope (with occasional disastrous falls) to expect energy market prices alone to support the cost of generation capacity – see the recent experience of the Texas energy-only market. Our opening comments referenced the CAISO annual reports, which for years have indicated gas fired generation only recovers a portion of average costs in the energy market. Thus, it is not unreasonable to recognize that, even during sufficiency years, the price paid to existing resources that are able to continue operations must include more than simply the wholesale energy market price. Existing generators must recover their ongoing costs for O&M and capital additions if they are to remain in business. Resource adequacy markets, such as the bilateral RA market in California, show this.[5] The staff proposal to set capacity value at fixed O&M costs phased in over three years (0% in year 1, 33% in year 2, and 67% in year 3) is a more reasonable estimate of capacity value during the sufficiency period than a zero value in all years of the sufficiency period.

The Joint Utilities' comments make the point that fixed O&M costs are not an avoidable cost because they are fixed costs. They argue that, if costs must be incurred regardless of whether a resource is dispatched or not, those unavoidable costs should not be assigned as a value of dispatching some other resource instead. We agree, in terms of energy value alone. However, we note that when it comes to selecting which resources to retire or which to continue operating, O&M and capital addition costs are an incremental cost. If a resource is retired, those costs are not paid. If it continues operation, another year of O&M costs must be paid. These O&M costs are thus part of the annual average cost faced by existing resources that must be recovered if the existing resource is to continue to be available as a capacity resource and recover its average costs, e.g., for one more incremental year of existence. Consistent under-recovery of these

[5] See Table 6 of the 2019 annual RA report, at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442468127

allegedly "fixed" costs would force retirement. Investors must recover incremental costs plus a return, not just variable energy-related cost. Thus, the view that capacity value is zero during the sufficiency period, does not recognize that marginal energy cost is not the same as the avoided cost of capacity procurement (i.e. whether to procure capacity from a given resource for one more year is different than selecting what procured units should be dispatched for energy).

The utility argument that customers would pay twice for capacity – once from the existing resource, and again as part of the sufficiency period capacity value – is incorrect, given the new resource (if those prices were sufficiently attractive) should be able to displace the existing resource in the portfolio. This is a fundamental underpinning of PURPA avoided cost principles, i.e., the principle that avoided cost is the cost the utility would have otherwise incurred had it *generated* or contracted for the power in the absence of the QF.

Marginal cost pricing is intended to attract those resources that are best able to beat that cost. Thus, the view that during the sufficiency period, utilities have the resources they need, and any other resource results in excess generation ignores the economic efficiency (and PURPA) goal that is achieved by allowing the set of resources serving existing load to be determined by those resources with marginal costs less than system marginal cost. It would be contrary to PURPA to set avoided cost to zero, simply because need has been met by existing resources, without allowing for competition to serve that existing need. There should still be a system marginal cost, such that new resources with lower marginal costs are able to displace existing resources with higher marginal costs. Avoided cost does not drop to zero simply because a set of resources has been selected that serves existing load.[6]

Capacity prices in Resource Adequacy (RA) programs typically reflect the short-term capacity value. As noted in our opening comments, we expect an RA program in Oregon may be useful for future guidance on this issue, to the extent it is developed. We also supported ramping up from the fixed O&M value to the deficiency period value, rather than simply ramping up from zero to the fixed O&M value, during the sufficiency period. It makes no sense to value capacity during the sufficiency period at less than the fixed O&M value during staff's proposed 3-year sufficiency period, particularly if wholesale energy markets tend to cover only variable costs of the proxy resource. [Again, I would add the point that if it is prudent for utility self-build of capacity resources during capacity sufficiency (and it may be), then the competitive market should be placed on an equivalent economic footing.]

4. Proxy Resource Identification

[6] Similarly, we disagree with the Joint Utility comment that once a given level of reliability has been met – i.e., enough supply exists to reliably meet demand – ratepayers should not have to pay for additional reliability. This ignores that you want resources to be able to compete with each other to provide that supply and reliability at lowest cost.

The Joint Utilities agree with staff that a gas-fired simple cycle combustion turbine (SCCT) continues to be the appropriate proxy resource for generic purposes. But the utilities argue IRP modeling shows capacity needs can be met at lower cost than a SCCT, and that not only SCCT capacity additions are selected. The Joint Utilities argue that compensation based solely on an SCCT proxy could result in avoided costs based on a SCCT-only portfolio.

We respond that the SCCT proxy, to the extent it is used, does not imply that the entire utility system consists of SCCTs or that those are the only type of resource added. It simply has to be a choice for the marginal or incremental capacity addition, not the makeup of the entire existing (rather than incremental) capacity supply. Basing avoided capacity cost on a new SCCT that could be added allows all resources with lower costs than the incremental cost of adding an SCCT to be selected instead. It would not make sense to lower the proxy cost to some infra-marginal resource cost (such as wind and solar selected in the IRP in the near term), if the system's next incremental capacity resource is an SCCT (or some other form of near-perfect capacity, such as battery storage).

Also, as discussed in the next section, resources do not get the entire SCCT proxy price, given that an ELCC value (less than 100%) would be applied to the proxy resource capacity value in order to calculate the capacity value for a given resource in question such as solar PV.

However, other types of capacity additions may be appropriate to consider. The Joint Utilities note that this docket should help identify where it is more appropriate to use a "comparable" proxy (i.e., solar displacing other solar) instead of the SCCT proxy. For example, if no SCCTs are being built, and another form of pure capacity addition is considered instead (e.g., battery storage), then the proxy resource should be based on the cost of that type or resource. For example, in California, PG&E has moved in its most recent general rate case to a marginal generation capacity cost based on storage rather than gas-fired capacity. In the IPC IRP, where 300 MW of gas-fired capacity is added in 2031 (see IRP Table 10.2), for example, one might want to consider the 30 MW of battery storage added in 2030 as the proxy resource instead. Even the 120 MW of solar in 2022 may have a non-trivial amount of capacity value (even with an ELCC that is much less than 100%), and also could be considered as a proxy. This is especially true given IPC's commitment to 100% emissions free resources. PGE's Wheatridge facility may be a more appropriate proxy to use since Oregon and Washington are not likely to build another SCCT within the planning horizon.

As an example of expected resource costs, IPC's 2019 IRP indicates (at Figure 7.5) levelized capacity costs of various types of resources, including: (1) SCCT Frame F Class ($132 per kW-year), (2) Solar tracker paired with battery storage ($180 per kW-year), and (3) 4-hour Li Battery Storage ($240/kW-year). We note that whatever proxy is selected, the annualized costs should be net of the resource's value in the energy market, and it should be adjusted to have an ELCC near 1.0 (or the cost should be divided by its ELCC if it is less than 1.0 in order to for the proxy resource to estimate the cost of "perfect" capacity). For example, PGE's IRP noted that the SCCT ELCC is about 95%.

5. Effective Load Carrying Capacity (ELCC)

Joint Utilities argue ELCC should be based on a single IRP "test year" rather than being computed for multiple years as staff has proposed. The Joint Utilities (at page 6) state that it would be inconsistent with IRP modeling to update ELCCs annually. We think this is an issue that may be more appropriate for contractual payment determinations. It is also somewhat unclear what annual updating means: would ELCC values be set now for each future year, or would they be updated each year for the current year? In opening comments, we raised the possibility that future electrification efforts could change today's outlook of ever-dwindling ELCC values as more and more solar capacity is added to the system. Transportation and building electrification efforts, as well charging loads from the more prevalent use of battery storage capacity, are likely to impact hours when capacity is considered most valuable.

There is also the issue of what type of ELCC metric should be selected. The Joint Utilities support last-in (or marginal) ELCC. Our comments recommended a portfolio approach. There are also various methods of determining solar capacity contribution, as E3 has noted – for example IPC's IRP looks at the difference between the top 100 hours of system peak loads and system net peak loads (subtracting wind and solar). These distinctions can be significant. For example, IPC's IRP assigns about 62% capacity contribution to existing solar PV, 48% to solar PV projects under construction, and decreasing amounts for additional 40 MW capacity additions (descending from 45% to less than 10% after adding 20 x 40MW=800 MW).

PGE's IRP notes (at Tables 14-16) marginal ELCC values for solar PV and for storage. PGE's solar ELCCs decrease from 5.5% for a 100 MW addition, to 2.7% for 800 MW added. Solar plus storage values decrease from 21.3% to 10.0% over this same range.[7] Storage resource ELCCs are indicated as 94% for the first 100 MW, but also drop as more storage is added (i.e., 88.5% with +400 MW). Thus, it is clear that ELCC values computed today will indicate dwindling ELCC values as more resources are added.

A portfolio ELCC could look at the ELCC of all additions of resource type or group of resource types, not just for example the final 100 MW addition of solar PV after other 100 MW additions are made. It is not clear that reduced ELCC values to capture marginal capacity value are preferable to ELCC values that reflect the entire portfolio of a resource type being added to the system. For example, a portfolio version of the IPC IRP results above presumably would be between the 48% and 10% values for the first and last capacity additions, respectively, if the

[7] We question why solar plus storage ELCC is so low, compared to storage ELCC. Battery storage can be dispatched, so it is unclear whether these low values for solar plus storage are a function of small storage capacity relative to PV size, or vice versa (i.e., problems filling storage)

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capacity additions were considered as a group (excluding existing and capacity under construction). We doubt that it is important to provide very different values to different resources depending on who was first in line, and it would be better and more equitable to assign an average portfolio value so that all additions are considered equally.

As noted above, we disagree with the Joint Utility assertion that a resource's capacity value cannot exceed the utility's need for capacity. To be sure, the cost of the required amount of capacity available to meet demand in any given hour might determine how "tight" is the supply-demand balance in that hour, such that a given capacity contribution is worth more in some hours than in others. However, the amount of capacity that a resource is deemed to provide (as opposed to its $ value) should not depend on whether a utility already has enough capacity from other resources.

6. Compensation for Capacity Value

Staff has noted that compensation methods, rather than value, are not in scope. The Joint IOUs commented that compensation for capacity value is intertwined with other terms/conditions such as performance obligations. For example, capacity value methods determined in this docket when combined with energy and other contract payments should not result in aggregate overpayment. We agree. We would add that they also should not result in underpayment. E3 presented interesting concepts regarding compensation frameworks in this proceeding. We recommend that, whatever capacity valuation method is ultimately adopted in this proceeding, there should be some clarity on what issues are left open to be determined when considering compensation issues in other dockets (e.g. in RVOS and PURPA dockets), and what issues have been determined or may be adapted. Too much flexibility risks making this proceeding meaningless, but too little flexibility runs the risk that compensation methods may produce inadequate or inaccurate capacity values.

As an example, we take note of the staff and E3 discussion of "ELCC to LOLP coincidence values." We understand RVOS modeling makes use of this concept. We think it is worth considering standards for LOLP adjustments. For example, it makes sense for an LOLP adjustment to capture differences between the results of 12x24 average LOLPs applied to a 12x24 solar profile, and of an 8760 set of LOLPs applied to an 8760 hour solar profile; however, it may be less reasonable to use an LOLP adjustment factor as a way to incorporate a specific ELCC value end result determined elsewhere that essentially overrides an analysis of hourly generation and LOLP profiles. The Commission should decide, whether this docket should indicate standards for such issues, or whether this are a compensation issue best left to other proceedings.

E3's report contained lengthy discussion of compensation structures (pages 15-22), including a discussion of LOLP adjustment using the ELCC to LOLP-generation coincidence ratio. See pages 17-19, including the detailed numerical 111% adjustment example on page 18. Staff also

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dedicated significant space to describing compensation. See staff's opening comments at pages 11-18. If these valuable discussions of compensation issues by E3 and by staff are outside of scope of this proceeding, we would hope the E3 report and staff's comments are made available in other dockets that may consider this same issue, so that these important considerations are not lost, parties have an opportunity to comment, and reasonably consistent results can be achieved.

OSSIA appreciates the opportunity to comment and will continue to engage in this docket.

Sincerely,

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