Via Electronic Mail

August 9, 2018

Public Utility Commission
Attn: Filing Center
PUC.filingcenter@state.or.us

Re: PORTLAND GENERAL ELECTRIC COMPANY, Resource Value of Solar.
Docket No. UM 1912

Dear Filing Center:

Enclosed is OSEIA's closing brief for the RVOS docket referenced above.

Thank you for your attention to this request.

Sincerely,
/s/ Jon Miller
Jon Miller
Executive Director, OSEIA

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UM 1912

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Resource Value of Solar.	CLOSING BRIEF OF OSEIA

The Oregon Solar Energy Industries Association (OSEIA) respectfully submits this closing brief in the above-referenced docket. OSEIA has participated in this docket because the Commission's determination of the resource value of solar (RVOS) will profoundly impact the future of the distributed solar systems in Oregon. These solar resources are developed and installed by OSEIA members and used by our customers to serve their electricity needs. OSEIA and its witness R. Thomas Beach of Crossborder Energy have presented a rigorous, best practices approach to the calculation of the RVOS.

All of the parties to this docket appear to agree with the basic spreadsheet template for the RVOS developed by Energy and Environmental Economics, Inc. (E3) work, with this agreement affirmed by all parties testifying at the June 25th, 2018 hearing. We believe this uniform approach for all three utilities is essential to the success of any future use of the RVOS values. There is less agreement, however, on the methodologies to be used by the three IOUs to calculate the eleven elements of the RVOS that the Commission adopted in Order 17-357 and that are included in the E3 model. OSEIA urges the Commission to adopt uniform methodologies to calculate each element of the RVOS, in order to avoid confusion and bring consistency to the calculation of each RVOS element. This does not mean that the RVOS will be the same for the three IOUs, because each utility has its own service territory, distinct resource needs, and different cost structures, which will result in different input assumptions for the calculation of each element of the RVOS.

OSEIA has recommended a number of changes to the RVOS calculations that Portland General Electric (PGE), PacifiCorp (PAC), and Idaho Power (IPC) submitted in this docket. These modifications result in RVOS values that are more consistent with the direction that the Commission provided in Order 17-357, use more accurate and consistent methods, and are more up-to-date than what the utilities have proposed. This reply brief will respond to the criticisms of OSEIA's modifications contained in the opening briefs of the IOUs and several other parties. We have organized this reply brief based on the specific RVOS components about which the opening briefs showed that there is significant disagreement among the parties.

1. **Avoided Energy.** OSEIA and PAC agree that forecasted wholesale energy prices should be shaped using hourly prices from the regional Energy Imbalance Market (EIM). The EIM market is the best source of hourly market price data for the Oregon IOUs; this level of transparent, hourly granularity is not available in the traditional wholesale markets such as Mid Columbia. The only minor difference between OSEIA and PAC is that the utility arbitrarily caps these real-time EIM prices in a small number of hours that experienced very high or very low prices. PAC's proposed caps are arbitrary, and in essence discard important information from the market about the impacts of congestion, scarcity, or ramping that can produce these brief episodes of high real-time prices. OSEIA agrees with PAC that these rare price excursions "are generally the result of unexpected market conditions."[1] But the fact is that unexpected events do occur from time to time, and produce real if brief impacts on the market. It does not somehow "improve the price shape," as PAC asserts, to exclude them,[2] instead it makes the price shape less realistic. PAC has provided the Commission with no reason why this real market data should be ignored.

   OSEIA recommends that all three utilities should use this EIM approach to shape their avoided cost for energy, as this is the best available market data on the hourly shape for market energy. We note the Staff's suggestion to use Aurora or other dispatch modeling to produce 12x24 hourly price shapes.[3] We agree that this is also a feasible approach; however, there is no such modeling available on the record of this

---

1 See PAC Opening Brief, at p. 7.
2 *Ibid*.
3 Staff Opening Brief, at pp. 5-6.

docket for parties to review, and no solid basis for concluding that this would be a superior approach to using the readily-available EIM price data.

2. **Generation Capacity.** To recognize accurately the shorter lead times and smaller capacity increments that distributed solar resources will provide, OSEIA recommends that the IOUs follow the suggestion of Order 17-357 to advance by up to four years the "resource balance year" when each of the IOUs will need capacity. Our proposal recognizes that new utility-owned resource additions are made in larger "lumps" of capacity that necessarily result in several years of excess capacity between resource additions. The costs of this excess capacity can be avoided by distributed energy resources, including distributed solar, that are smaller in size and offer shorter lead times. Avoiding such excess capacity provides a benefit that is equivalent to moving the resource balance year (when the first new resource is added) forward by up to four years.[4] The key metric here is to compare the rate of change in the utility's capacity position (in MW per year) to the size of its next planned resource (in MW). Thus, if a utility's capacity position is changing by 50 MW per year (due to load growth and retirements) and its next resource addition is a 200 MW CT, the new resource will add up to four years of excess capacity.[5]

PAC also argues that its next resource will be fully needed in the first year because it will fully replace the utility's prior market purchases of capacity.[6] However, the new resource is needed in that year (2029) because the utility's need just exceeds

[4] PAC argues that excess capacity costs after the resource balance year are different than paying DERs an additional amount for capacity provided in years before the resource balance year. Ibid., at pp. 12-13. OSEIA's point is that the resource value year should be brought forward for DERs for a number of years that provides equal value to the reduction in excess capacity costs after the resource balance year, and OSEIA's recommendation includes this timing difference.

[5] Both PGE's and PAC's recent IRPs plan to add new gas-fired resources that are three to five times larger than the expected annual change in their capacity position. For example, see PGE 2016 IRP, at pp. 29-30, adding a 375 to 550 MW dispatchable combined-cycle plant to resolve a near-term capacity position that is increasing by about 160 MW per year (i.e. by 819 MW over 2017-2021). Also, PAC's 2017 IRP would add a 200 MW combustion turbine in 2029 and a 436 MW combined-cycle in 2030 to meet a capacity position that is increasing by about 80 MW per year; see pp. 7 and 11 (Table 1.2).

[6] PAC Opening Brief, at p. 12.

the level of available market capacity. As a result, PAC's actual need above the level of available market capacity is far smaller than the resource that the utility would add, showing that PAC is indeed adding excess capacity. Finally, IPC says that "OSEIA's argument depends on a hypothetical future in which hundreds of additional megawatts of distributed generation capacity eliminate the need for additional utility-scale capacity, which is very unlikely and too speculative to support reliable planning for utility customers." Although this statement may be true today for Idaho, there already are numerous states, including Oregon,[7] in which the penetration of DG exceeds the typical size of utility-scale generation resources.

3. **Avoided T&D Capacity.** OSEIA has recommended using consistent methods across the three IOUs to calculate the long-run transmission and distribution (T&D) capacity costs that distributed solar can avoid. For transmission capacity, we accept PGE's approach of using current FERC-approved bulk transmission rates as a reasonable proxy for marginal transmission costs. To promote a consistent and transparent RVOS, we recommend that the other IOUs use the same approach based on each utility's own FERC-approved transmission rates. For distribution, the RVOS should use the full set of capacity-related long-run marginal distribution costs from the utility's current marginal cost study, if such as study exists. PGE does have such a study, and the RVOS should use all capacity-related elements of PGE's marginal distribution costs (not just the marginal subtransmission and substation costs that PGE proposes to use), because small, behind-the-meter solar DG also can avoid marginal distribution feeder costs.[8]

For PAC and IPC, we recommend using the well-accepted NERA method for calculating these utilities' long-run marginal distribution capacity costs. The Staff also supports this approach if a utility-specific marginal cost of service study is not available.[9] This approach uses a regression of historical and forecasted distribution investments as

[7] Oregon had 462 MW of installed solar capacity as of the end of 2017; about 50% of this was DG solar. See https://www.seia.org/sites/default/files/2018-06/Web2018Q1_Oregon.pdf.

[8] See OSEIA/100, Beach/22.

[9] Staff Opening Brief, at p. 12.

a function of peak loads. PAC criticizes this method for failing to consider that some distribution investments (which it characterizes as "non-deferable") are made to improve reliability or to replace aging equipment, and not primarily to serve load growth.[10] This argument fails to understand that the whole purpose of the regression analysis in the NERA method is to address this exact concern – the reason to use a regression analysis is to isolate just the portion of distribution investments that are driven by peak load growth. Distribution additions can serve multiple functions – for example, replacing aging equipment primarily to improve reliability also can result in an increase in capacity as a secondary benefit. This additional benefit is captured in a regression analysis that uses all of the utility's distribution investments, while it would be improperly ignored if such "non-deferable" distribution additions are excluded from the calculation of marginal distribution costs.

PAC also disputes our addition of an O&M loader to marginal distribution costs, using FERC Form 1 data.[11] However, the unavoidable facts are (1) investments in distribution plant must be maintained over time through annual expenses for O&M and (2) increases in distribution investments result in higher distribution O&M.[12] As a result, new investments in distribution produce new O&M expenses; this is what is captured in the O&M loader. Our calculation of an O&M loader using Form 1 data is a standard feature of the NERA approach.

4. **Avoided Line Losses.** The Commission should adopt the use of marginal line loss factors, as these are the correct measure of the costs avoided by a marginal change in demand. PGE appears to have used average line losses.[13] OSEIA accepts PAC's

---

[10] See PAC Opening Brief, at pp. 13-14.

[11] *Ibid*., at p. 14.

[12] PAC's assertion that most distribution O&M is "not avoidable" would mean that distribution O&M should not change over time, even if the utility's system is growing and the company is investing in more distribution plant. However, the FERC Form 1 data shows clearly that distribution O&M grows as more distribution plant is added. Inspection of the FERC Form 1 data in OSEIA's workpapers for the NERA method calculations shows that distribution O&M as a percentage of distribution plant in service is stable over the 15 years of data used, even as distribution plant in service is growing.

[13] See PGE/400 Murtaugh/3 to 5.

explanation in its opening brief that it has used marginal losses.[14] OSEIA provided for the record a white paper from the Regulatory Analysis Project (RAP) that calculates that marginal losses are typically 1.5 times average losses. To the extent that a utility does not have their own calculations of marginal line losses and only have provided average line losses (i.e. PGE and IPC), the Commission should apply RAP's reasonable approximation of marginal line losses until the utility can perform their own study of marginal line losses.[15]

To be clear, all parties appear to recognize the need to use of loss factors which vary across the hours of the day as system load levels change. This is necessary to estimate accurately the line losses avoided by solar generation that is produced only in the hours when the sun shines. However, this is a different issue than the question of whether to use average or marginal losses. Marginal losses are those associated with a small change in system loading and are the correct value to use for distributed resources that have a small impact on line loadings.

5. **Administration.** PAC's administrative costs appear to follow the guidelines in Order 17-357 that limit administrative costs to incremental costs associated with a customer's decision to install on-site generation. PAC's administrative costs of about $2 per MWh are in line with those of other utilities in the West with active solar programs. OSEIA continues to recommend using this value for all three utilities, as we see no reason why utilities of the size and sophistication of PGE and IPC cannot achieve similar efficiencies in administering their solar programs.

---

[14] See PAC Opening Brief, at p. 16.

[15] IPC's reply testimony moved to the use of marginal losses, but excluded losses on the secondary distribution system on the grounds that excess solar generation at times is exported to the distribution system, resulting, IPC asserts, in additional losses. IPC/200 Haener/17 to 19. However, IPC did not provide any studies documenting or quantifying this assertion. In most cases, DG exports will replace upstream sources of power that otherwise would have served loads nearby to the DG customer, thus reducing line loadings (and line losses) upstream of the DG customer on the secondary system. It is only in the rare cases where DG exports are larger than all neighboring loads that one would expect losses on the secondary system to increase.

IPC's opening brief continues to argue that its administrative costs should reflect those of a pilot solar program in its small Oregon service territory.[16] The result is that these costs, when spread only over IPC's small load in Oregon, reduce almost to zero the utility's RVOS. This reflects a general problem with IPC's RVOS – its selected use of data from only its Oregon service territory when that data is useful for driving down its RVOS. As another example in addition to the administrative costs, IPC's large service territory in Idaho and Oregon is strongly summer-peaking, but IPC argues that solar cannot defer transmission capacity costs because its Oregon loads peak on winter mornings when solar output is low.[17] IPC's transmission system serves all of its loads, including those in Oregon, and that system peaks on hot summer afternoons.

6. **Market Price Response.** OSEIA has accepted PGE's calculations using the Aurora model of the market price response to increased solar deployment, and we recommend using PGE's results (about 4% of avoided energy costs) for all three IOUs. IPC suggests that OSEIA is proposing to use an MPR value that was developed in the New England market.[18] This is not true; we simply compared the PGE MPR value, as a percentage of avoided energy costs, to comparable values calculated in New England. The New England region has the most elaborate and sophisticated calculation of the market price reductions associated with an increasing penetration of zero-variable-cost renewable resources. The comparison to New England is simply to show the approximate order of magnitude for a well-established MPR adjustment, as a reasonableness check on the utility calculations.

PAC and IPC criticize the use of the MPR value on the basis of an assertion that they are net sellers of energy, such that a lower market price will reduce their sales revenues. We note, first, that PGE's MPR calculation includes consideration of periods when PGE has been a net seller. In addition, we note that, with respect to the impact of new solar generation on market prices, the principal impacts of new solar will be to

[16] IPC Opening Brief, at pp. 9-11.
[17] *Ibid*., at p. 7.
[18] *Ibid*., at pp. 12-13: "Idaho Power is not a member of the New England ISO, or any other ISO."

decrease daytime, on-peak market prices, when the utilities are more likely to be net buyers. For example, PAC's IRP shows net market purchases to meet peak demands for many years.[19] Finally, PAC argues that the MPR is zero during the deficiency period because the solar generation offsets power that would otherwise be produced by the avoided resource.[20] This is incorrect because these resources are at different places in the dispatch stack: the solar output has zero variable costs and will reduce market prices, while the output of the avoided gas-fired resource will be a marginal resource that is more likely to set the market price at a higher level.

7. **Hedge Value.** Distributed solar displaces the marginal use of natural gas to generate power, and thus reduces ratepayers' exposure to volatile fossil fuel prices. OSEIA has quantified this hedging benefit using a method that Clean Power Research developed for the Maine Public Utilities Commission. This approach recognizes that the value of the hedge that a renewable resource provides is equal to the cost that the utility would have to incur to fix the costs for its avoided natural gas burn for the life of the renewable resource. The utilities and Staff criticize this approach in several ways. First, PAC asserts that, "although the premise of a risk premium may be valid," this benefit is already included because the natural gas forecast is based on forward market prices.[21] However, simply using a forecast based on forward market prices does not reflect the financial cost that the utility would have to incur to set aside, when the renewable resource first enters service, the money needed to pay for the avoided natural gas burn for the life of the renewable resource. This includes the significant opportunity cost of setting aside upfront, in risk-free investments, the money needed to make future gas purchases at forward market prices, instead of being able to devote these funds to more profitable investments at a higher rate of return such as the utility's cost of capital. It is necessary to include this significant opportunity cost because the essence of a renewable resource is replacing ongoing, uncertain fuel costs with a one-time, upfront

[19] See PAC 2017 IRP, at p. 6 (Figure 1.6).
[20] See PAC Opening Brief, at p. 19 and Figure 4.
[21] *Ibid*., at p. 23.

capital investment that allows one to harness zero-cost wind or solar energy for 20 to 30 years.

Further, there is no merit to the Staff's complaint that the study supporting OSEIA's proposal relies on "mere guesses" of long-term natural gas price forecasts.[22] The method uses the current long-term gas forecast that represents the best available information on future gas prices. OSEIA does not oppose using a utility's most recent gas forecast in the calculation of the fuel price hedge value, if that forecast is more up-to-date than the forecasts that OSEIA used.[23]

The utilities complain about the magnitude of OSEIA's fuel price hedge benefit,[24] but it reflects perhaps the most important benefit of renewable resources for ratepayers: the "fuel" is free and is certain to be available for the life of the resource. At a minimum, the Maine PUC's method shows that the hedge value of renewables substantially exceeds the 5% proxy referenced in Order 17-357. The 5% proxy value is based on a recommendation from E3 cited in Order 17-357 that in turn appears to be based on a paper from several E3 consultants on the short-term (i.e. no more than 2-3 years) hedge value of electric market futures contracts in the Pacific Northwest.[25] This significantly undervalues the hedge value of a 25-year solar resource.

Finally, the Staff argues that there are no examples of utilities being willing to pay such a large premium to hedge their exposure to fuel price volatility.[26] That is because purchasing long-term renewable generation represents a less expensive way to achieve the same long-term hedge, as studies cited by OSEIA's testimony have

---

[22] Staff/300, Andrus/18-20.
[23] This responds to one of IPC's criticisms; see IPC Opening Brief, at p. 14.
[24] See, for example, PAC Opening Brief, at p. 22.
[25] See Order 17-357, at p. 12, based on Docket No. UM 1716, Exhibit Staff/200 and Olson/43. The E3 paper is cited on the record by staff; see Exh. Staff/100 Andrus/45, at lines 11-13 and footnote 47.
[26] Staff Opening Brief, at p. 20: "Utilities are not willing to pay between $18.00 and $23.00 per MWh to hedge against market volatility."

demonstrated and as utilities such as PAC have admitted in past IRPs.[27] We offer the Staff the gentle reminder that a fundamental purpose of utility regulation is to encourage monopoly utilities to make investments for the long-term benefit of ratepayers that the utilities would otherwise refuse to undertake.

8. **Environmental Compliance.** PAC criticizes OSEIA for what it characterizes as our recommendation that the same avoided costs for reductions in carbon emissions should apply to all three IOUs.[28] This mischaracterizes OSEIA's testimony. Our position is that it is reasonable to assume that any compliance regime for carbon emissions will apply to all utilities in Oregon and that this regime effectively will place a price on carbon emissions.[29] If the utilities have different marginal emission rates, OSEIA would support using utility-specific marginal emission rates in each utility's RVOS. This would also be generally consistent with the Commission's direction in Order 17-357 that each utility should calculate a placeholder for environmental compliance costs "based on a reduction in carbon emissions from the marginal generating unit."[30] OSEIA recommends the use of a common assumption for a statewide or regional carbon price, instead of the planning prices for carbon used in individual utility IRPs. We expect that a regional approach to pricing carbon will bring the greatest efficiency and certainty to regulating carbon emissions in the West.

Alternative RVOS based on Utility-scale Solar. OSEIA's testimony also commented on the alternative RVOS approach that uses the cost of utility-scale solar as a proxy for all of the RVOS elements except T&D capacity, administration, and line losses. This alternative RVOS is misleading and fails to capture important, quantifiable benefits of distributed solar. These include additional benefits when paired with storage (including enhanced reliability and

---

[27] See OSEIA/100, Beach/32 (footnote 43).
[28] PAC Opening Brief, at p. 26.
[29] Neighboring states and provinces already are subject to such a regime (California and British Columbia), or have one under active discussion (Washington).
[30] Order 17-357, at p. 23.

resiliency), environmental benefits from reduced land use impacts, and the important benefit of increasing customers' ability to choose their source of electric energy.

PAC argues that these added benefits accrue to participating solar customers, not to non-participating ratepayers.[31] OSEIA disagrees with PAC's assertion. The significant added benefits from storage that OSEIA calculated are realized directly by non-participating ratepayers, because storage will shift solar output into hours when the generation is most valuable to the system and the direct avoided costs are the highest. Environmental benefits, such as reduced land use impacts, accrue to all citizens, which includes all ratepayers. An electric system that is based on many small, distributed generators is inherently more reliable than a grid that relies on a small number of large generators whose failure can place the entire system at risk. Again, all ratepayers benefit from this enhanced reliability. Further, there are broad public benefits if solar plus storage systems can provide backup power to critical communications and public safety infrastructure. Finally, all ratepayers gain additional freedom when they have a real opportunity to exercise the choice to supply some or all of their electricity using their own private capital to build generation on their own premises.

As OSEIA discussed in its testimony, these additional benefits offset the higher costs of distributed solar. The bottom-line result is that both distributed and utility-scale solar provide comparable net value to the ratepayer. Both types of solar should have central roles in the transition to a clean, sustainable, and resilient electric industry.

Dated August 9, 2018

Respectfully submitted,
/s/ Jon Miller
Jon Miller
Executive Director, OSEIA

[31] PAC Opening Brief, at p. 29.