BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1910, 1911, 1912

In the Matters of:

PACIFICORP, dba PACIFIC POWER, Resource Value of Solar (UM 1910)

IDAHO POWER COMPANY Resource Value of Solar (UM 1911)

and

PORTLAND GENERAL ELECTRIC COMPANY, Resource Value of Solar (UM 1912).

STAFF's REPLY BRIEF

This is the final brief in Docket Nos. UM 1910-12. In this brief, Staff limits its discussion to issues on which there is some disagreement among parties or to clarify previous Staff testimony.

A. Energy value.

As discussed in testimony and the opening brief, the Commission identified three components of the calculation of the value for energy: (1) the forward price curve, (2) the shape of the prices by hour, and (3) the potential impact of varying hydro conditions on the prices. No issue remains with respect to the third component, the hydro variability. There is a disagreement related to one aspect of the selection of the forward price curve and a general disagreement as to how to determine the 12 x 24 hours shape. Staff discusses both issues below.

1. Forward price curves.

There appears to be no dispute relating to the source of the forward price curves. Under Order No. 17-357, each utility must use the same source of forward price curves for the RVOS calculation as the utility uses to determine standard avoided cost prices. However, there is a dispute as to whether utilities should always use the same vintage of forward price curve as is used for the currently effective standard avoided cost prices. This is what PacifiCorp recommends. Staff recommends that the utilities should use the most recently available forward price curves.

Staff does not think it is necessary to rely on the same vintage of forward price curve used by the most current standard avoided cost prices approved by the Commision. Notably, the forward price curve is not inextricably linked to other IRP inputs. For example, when PacifiCorp made its post-IRP-acknowledgment avoided cost filing in April 2018, PacifiCorp used March 2018 forward price curves for its energy prices rather than the forward price curves used in its IRP.[1] Staff believes it is appropriate to incorporate the most recently available prices into the RVOS calculation rather than using more stale prices.

2. 12 x 24 shape.

The forward price curves used by the utilities are forecasts of energy prices in monthly on- and off-peak blocks. The Commission ordered utilities to shape these monthly blocks into 12 x 24 blocks (one 24-hour shape for each month) to account for varying prices in different hours.[2] To do this, each utility identified a source for hourly prices. The hourly prices from that source are not used to value the energy directly, but to create a set of hourly shaping factors that are then applied to the utility's monthly price forecast. The hourly prices for each month, when averaged, are equal to the utility's monthly price forecast, just as the average of the shaping factors is one.

There is little consensus in these dockets about the appropriate source of the hourly prices or the method to create the price shapes. Each of the utilities used a

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[1] See PacifiCorp's UM 1729—Standard Avoided Cost Purchases from Eligible Qualifying Facilities—Compliance Filing, Table 2 (April 26, 2018).

[2] *In the Matter of Public Utility Commission of Oregon Investigation to Determine the Resource Value of Solar* (UM 1716), Order No. 17-357, p. 4.

different source for the hourly prices and a different method. Staff believes PGE's method is most consistent with the Commission's directions in Order 17-357 and recommends that the other two utilities use a similar method.

PGE created daily shape factor profiles for each month using hourly prices for 2024 produced by its system dispatch model, AURORA. PGE then applied the shape factors to the weighted average annual price (based on monthly prices) for each year to create daily price profiles for each month of the year. Staff believes the hourly prices produced by PGE's own system dispatch model, based on the prices in markets in which PGE operates, are appropriate representations of the prices that would be available were PGE to purchase solar generation.

PacifiCorp created the price shape using 15-minute Energy Imbalance Market (EIM) market prices for the 12 months ending September 2017. In its testimony, Staff noted its concern regarding PacifiCorp's reliance on the EIM for the price shape because most of PacifiCorp's transactions are not in that market, so the EIM shape may not accrately represent the value of solar to its system.

Idaho Power used two different shaping methodologies. Its first methodology uses data collected from Idaho Power's participants in the Oregon PV Pilot, Oregon Schedule 88. Its second methodology uses actual hourly Mid-Columbia ("Mid-C") market prices for 2017. Idaho Power's first method does not comply with Order No. 17-357 because it does not actually produce a 12 x 24 shape.[3] Idaho Power Company's second methodology appears flawed because the shaping factors do not average to one as they should.

Staff recommends that both PacifiCorp and Idaho Power use their system dispatch models as PGE has done to create a 12 x 24 shape for application to the energy price. As Staff noted in its testimony, PacifiCorp could still incorporate data from the EIM if

[3] UM 1911 Staff/200, Andrus/ 3-4.

PacifiCorp wished. But, including information from the utilities' system dispatch models would create 12 x 24 shapes more consistent with prices applicable to the value of energy generated in the utilities' territories.

Notably, it is not clear that EIM prices will provide a shape that is appropriate for PacifiCorp. PacifiCorp and OSEIA disagree on whether hourly prices that PacifiCorp considers to be outliers should be excluded. PacifiCorp asserts they should be excluded while OSEIA includes them. Given that PacifiCorp uses only one year of data from the EIM, it is difficult to know whether the prices are truly outliers. This ambiguity supports use of the utilities' system dispatch models

In any event, if the EIM method is allowed, it is appropriate to weight the average price in each hour by quantity of production as PacifiCorp recommends.[4]

B. Generation capacity.

1. Resource deficiency period.

Under Order No. 17-357, the utilities are required to "determine the capacity value consistent with the Commission's standard nonrenewable QF avoided cost guidelines."[5] When the utility is resource sufficient, the value is based on the market energy price. When the utility is resource deficient, the value is based on the contribution to peak of solar PV, multiplied by the capacity cost of a combined cycle combustion turbine.[6] A utility is considered to be resource deficient under the standard QF avoided cost guidelines starting the year in which the utility's IRP shows acquisition of a "major resource" (one that is at least 100 MW and has a duration greater than five years).[7]

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[4] *See* UM 1910 PacifiCorp's Opening Brief 8. Staff note: The weighting methodology that PacifiCorp suggests requires sub-hourly data. Accordingly, it could not be used if the source of hourly prices does not provide sub-hourly data.

[5] Order No. 17-357, supra, p. 21.

[6] *In the Matter of Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities* (UM 1189), Order No. 05-584, p. 26.

[7] *In the Matter of the Public Utility Commission of Oregon Investigation into Determination of Resource Sufficiency, Pursuant to Order No. 06-538* (UM 1396), Order No. 10-488, p. 3 (noting major resource for purposes of determining resource deficiency is same as major resource for purposes of competitive bidding guidelines); *In the Matter of Public Utility Commission of*

In Order No. 17-357, the Commission asked Staff to convene a workshop at a future time to explore options for valuing capacity additions incrementally during a utility's resource sufficiency period. The Commission stated that the issues to be explored at the workshop include: "(1) allowing the full capacity value up to a reasonable number of years before the deficiency year (e.g., three or four years) as recognition that it takes several years to ramp up infrastructure to avoid a major resource; (2) using the short run marginal cost of fixed operations and maintenance (O&M) as a proxy value as suggested by E3; and (3) other ideas arising from Commission dockets or those raised by the parties."[8]

The Oregon Solar Energy Industries Association (OSEIA) recommends that the Commission immediately adopt the first proposal and move up the resource deficiency date by three years for PGE and four years for PacifiCorp and Idaho Power. Staff opposed OSEIA's recommendation recommending the Commission allow Staff to explore this option at the workshop ordered by the Commission prior to any decision to implement it.[9]

2. Contribution to peak (CTP) factor.

In Order No. 17-357, the Commission contemplated that the CTP used in the determination of generation capacity value would be the CTP of the utility's proxy solar resource in the IRP. During a resource deficient period, a utility multiplies the contribution to peak of a QFs resource type by the capacity cost of the utility's avoided proxy resource. For example, if the utility's acknowledged IRP states that solar PV has a 25 percent contribution to peak, the capacity value would be 25 percent of the capacity cost of the avoided proxy resource.[10]

Oregon Investigation Regarding Competitive Bidding (UM 1182(1)), Order No. 12-007 ("Major resources are resources with durations later than 5 years and quantities greater than 100 MW.").

[8] Order No. 17-357, *su*pra, p. 7.

[9] UM 1910-12 Staff/300, Andrus/8.

[10] Order No. 17-357, *supra,* p. 7.

PacifiCorp's proposed method differs from the method outlined by the Commission in Order No. 17-357. PacifiCorp proposes to determine the contribution to peak value for a given solar resource based on the 12 x 24 loss of load probability (LOLP) in each hour. Staff acknowledges that the additional granularity proposed by PacifiCorp may be appropriate in future iterations of the RVOS Methodology. However, Staff believes that at this point, it is preferable that all the utilities use the method to determine the value for generation capacity as outlined in Order No. 17-357.

The methodology at issue in Phase II is a methodology to "produce a 25-year marginal levelized value for a generic, small-scale solar resource installed[.]"[11] The granularity PacifiCorp seeks is generally obtained using one of the four CTP values included in its IRP. More specifically, PacifiCorp's last two IRPs have included four solar CTP values, two for a resource oriented to the East, but one fixed the other tracking, and two CTP values for a resource oriented to the West, one fixed and one tracking. The Commission's method would allow PacifiCorp to include a CTP that is most consistent with the type of resource that may be subject to the RVOS.

C. T&D Capacity.

Staff recommends that the Commission order PacifiCorp and Idaho Power to use either a marginal cost of service (MCOS) study or the National Economic Research Associates (NERA) method described by OSEIA to determine the value for distribution capacity.

1. Distribution.

The methods used by Idaho Power and PacifiCorp to obtain a more location-specific distribution value are not sufficiently vetted and supported. In Docket No. UM 1716, Mr. Olson's testimony reflects that the location-specific information needed to make a more location-specific determination of the T&D capacity value is more than

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[11] Order No. 17-357, *supra,* p. 1.

simply identifying specific substation upgrades that the utility thinks are deferrable. Mr. Olson described the location-specific information that he thinks is necessary as follows:

> Advances in technology, such as internet connected smart meters, are making the collection and analysis of locational specific data possible where historically it hasn't been. Several states have tackled this new opportunity, notably California through its Distribution Resource Plan proceeding. California utilities are currently developing plans to "more fully integrate [distributed energy resources] into system planning, operations, and investment." As part of these plans, utilities will be required to demonstrate the capacity to integrate distributed resources into their systems, the locational benefits that different resources can offer, and actionable pilot programs and tariffs to incentivize and capture this value. These distribution-level resource plans are expected to provide valuable information about where distributed energy resources can be targeted to achieve the highest value. In the absence of location-specific distribution system planning data, more general data can be gathered from utility capital budgets. Depending on the use of the RVOS, these more general values may be sufficient to provide high-level estimates of avoidable utility transmission and distribution expenditures.[12]

Mr. Olson described how the information described above could be used in the calculation of RVOS.

> **Q. How can time- and area-specific marginal costing be used in estimating the Oregon RVOS?**
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> A. The RVOS Model that I describe * * * has the capability to incorporate hourly avoided costs at a given location on the system. Hourly avoided costs are estimated for a variety of categories such as energy, capacity, distribution deferral value, and others. The RVOS Model can be run multiple times with different assumptions to generate different values for different locations. However, in order for accurate time- and area-specific marginal costing to be incorporated into the RVOS, the utilities must collect and provide data on the location-specific benefits described above. In particular, Oregon IOUs may benefit from studying how the value of solar and other distributed energy resources differ between geographic locations based on the specific transmission and distribution system characteristics in that area. Because this level of granularity is not available at this time, my testimony focuses on the methodology for developing an RVOS and provides a sample value for solar at a generic location.[13]

PacifiCorp's and Idaho Power's attempts to obtain a more location-specific value by selecting a handful of substation upgrades that they identify as load-growth related and

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[12] UM 1716 Staff/200, Olson/12.

[13] UM 1716 Staff/200, Olson/12-13.

located where they believe additional solar resources could potentially impact the need for the upgrade is not the sophisticated analysis of time-and-area marginal costing that E3 seemed to contemplate.

Staff acknowledges the utilities' concern that using a MCOS could capture the value of new assets or upgrades that are not load-growth driven. However, PGE addressed this issue by narrowing the type of resources included in the calculation.[14] And, as OSEIA notes in its testimony, even upgrades that are reliability-driven can provide additional capacity benefits, which are appropriate included in the RVOS calculation. Finally, the Commission stated that the T&D capacity value need not be limited to load-growth related investments.[15]

2. Transmission.

Staff also recommends that the Commission order PacifiCorp and Idaho Power to use the method used by PGE to determine the value for transmission capacity. PGE's avoided transmission value is based on the distributed solar generator's ability to allow PGE to defer the cost of firm transmission service, and the price is based on BPA's 2018 tariffed Firm Point-to-Point transmission service with Scheduling, System Control, and Dispatch Service.

PacifiCorp included zero value for deferred transmission in its RVOS calculation, asserting that solar generation is not a viable alternative to transmission upgrades.[16] Idaho Power used the same method for both distribution and transmission.[17] As already noted, Staff does not think Idaho Power's method is sufficient.

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[14] See UM 1712 PGE/400, Murtaugh/7 ("The value for an avoided distribution asset was estimated to be the cost of the sub-transmission costs plus substation costs, in dollars per kW-year.").

[15] Order No. 17-357, *supra,* p. 9.

[16] UM 1910 PAC/200, Putnam/3-4.

[17] UM 1911 Idaho Power/100, Haener/8-9

D. Administrative costs.

This component is intended to capture costs that are both incremental to what the utility incurs for any other specific type of customer account and incremental to any portion of this cost that is paid by the interconnecting solar generator.[18] In addition, the cost must be incremental to costs allocated to ratepayers other than the solar generators. Once a utility program is implemented based on prices determined with the RVOS Methodology, those costs become part of the cost-benefit analysis specific to that program and not a generic RVOS cost, per se.[19]

PacifiCorp and PGE appear to have determined a reasonable methodology for identifying these incremental costs. Idaho Power has not. Idaho Power includes administrative costs that are passed along to all ratepayers eligible for the solar PV program through an automatic adjustment mechanism.[20] Accordingly, these costs are not incremental costs of the type that should be included in the RVOS calculation. Staff recommends that the Commission order Idaho Power to use a methodology that estimates only the incremental administrative costs described above.

E. Market price response.

1. Methodology.

The value for market price response (MPR) is the "estimated impact on [market] price under a specified solar penetration ($/MWh) multiplied by utility net market purchases or sales (MWh). This total $ amount is then allocated to all solar generation (MWh) to yield a final $/MWh avoided cost value which is allocated equally to all hours."[21] The equation is as follows:

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[18] UM 1716 Staff/401, Olson/11, Staff Response to TASC Data Request 10.
[19] Staff/100, Andrus, 36-37.
[20] See ORS 757.635(10).
[21] UM 1716 Staff/200, Olson/33.

Market Price Response = Δ Market Price $*$ Utility Net Short (Long)

Solar Generation

where:

Δ Market Price = change in market price ($/MWh) due to solar

Utility Net Short (Long) = the annual net sales or purchases (MWh) that each utility transacts *

Solar Generation = total quantity of annual solar generation (MWh), note this quantity must be consistent with the quantity assumed to create the Δ Market Price[22]

Staff provided the utilities with two options for determining the change in market price due to solar. The first option is to use a market price elasticity of -0.001 to -0.002 for each MWh of renewable energy (-0.0001 for light load hours and -0.002 for heavy load hours). The second option calls for the utility to complete sequential runs in a production simulation model, such as AURORA, with the addition of a significant enough increment of solar generation to affect the calculated market price during each hour. The price differences would then be used to derive a market price elasticity per MWh of energy produced from customer-owned solar resources.

Neither Idaho Power nor PacifiCorp applied the method for determining the MPR precisely as outlined by E3. Staff does not think the difference in outcome is necessarily significant, but believes that departure from the methodology provided by E3 at this time is inappropriate. It is too soon in this process to abandon the method proposed by E3.[23]

2. OSEIA proposal regarding MPR.

OSEIA argues that each utility should have a MPR value of 3.8 percent of avoided energy costs, consistent with a study from New England.[24] For Idaho Power and PacifiCorp, this change would significantly raise their MRP value, while PGE's would

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[22] UM 1716 Staff/200, Olson/33.

[23] In UM 1911 Staff/200, Staff testified that Idaho Power should consider the potential for solar development in the region to determine the market price response value over the 25-year period. This is incorrect. Each utility should consider only its own solar development when determining the market price response value to apply to the RVOS calculation for its service territory.

[24] https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf

decline. This is inappropriate, as the value from the MPR element is directly tied to a utility's long or short market position and the markets in which it transacts.

F. Environmental compliance.

In Order No. 17-357, the Commission concluded the value for environmental compliance would be zero at this time, but ordered the utilities to calculate a value for informational purposes:

> We direct the utilities to calculate a value for informational purposes, to be used as a placeholder in their initial RVOS filings. The utilities should estimate the avoided cost based on a reduction in carbon emissions from the marginal generating unit with the carbon regulation assumptions from their IRP. We will decide on the application of this element based on implementation of RVOS at a later time.[25]

Staff is not satisfied with Idaho Power's and PacifiCorp's informational estimate of environmental compliance costs. However, the shortcomings of their estimates may stem from limited analysis of carbon compliance costs in their most recent IRPs.

Staff anticipated that even if a utility did not assume any regulatory compliance costs in its base planning case, it could use the sensitivity analysis required by Guideline 8 to provide an informational estimate of potential carbon compliance costs that may be avoided with the purchase of solar generation. Commission IRP Guideline No. 8 provides.

> Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.[26]

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[25] Order No. 17-357, *supra,* p. 13.

[26] *In the Matter of Public Utility Commission of Oregon Investigation into Integrated Resource Planning* (UM 1056), Order No. 07-047, App. A, p. 6 (IRP Guideline 8).

G. RPS Compliance

The Commission has not yet defined the element of Renewable Portfolio Standard (RPS) compliance. The parties that discuss this element agree that it could measure the value solar has in reducing load and therefore, the utility's compliance obligation. Staff recommends that the Commission allow Staff to explore a methodology for determining this value with stakeholders.

H. Hedge value.

Staff recommends that the Commission retain the current method of using five percent of the energy value for the hedging value. Staff recommends that the Commission reject OSEIA's proposal that all utilities substitute a different hedge value because the proposal is inconsistent with the RVOS Methodology adopted by the Commission.

The hedge value included in the RVOS Methodology is the cost of hedging the utility avoids by procuring energy from a solar resource. The costs associated with generation from thermal sources can vary widely whereas the price of solar generation is relatively constant. To the extent that a utility acquires a solar resource as part of its generation portfolio it is avoiding the need to acquire generation from another source (i.e., a natural gas-fired plant or a market purchase). Accordingly, the solar generation decreases the amount generation cost the utility must hedge and therefore, reduces the utilities' hedging costs.[27]

For purposes of valuing avoided hedging, E3 proposed that utilities use five percent of the value for energy based on a "peer-reviewed paper "How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest."[28]

The value proposed by OSEIA however, is not limited to an estimate of the cost of hedging that the utilities avoid by having solar generation. OSEIA also includes an

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[27] UM 1716 Staff/401, Olson/23-24 (Staff Response to TASC DR No. 20).
[28] UM 1716 Staff/401, Olson/23-24 (Staff Response to TASC DR No. 20).

estimate for the value of solar as a hedge against market price volatility. E3 rejected the idea that this value should be included in the RVOS calculation for rooftop solar because this hedge value does not accrue to the ratepayer, but to the owner of the solar generation:

> [T]to the extent that a utility acquires a solar resource as part of its generation portfolio, that resource allows the utility to avoid market purchases of electricity and/or natural gas and any associated hedging costs. However, for behind-the-meter generation, this value accrues to the owner of the solar installation, not to non-participating utility ratepayers. Solar owners acquire the resource for the purpose of offsetting all or a portion of their onsite consumption, thereby replacing their potentially variable electricity bill with a more stable cost stream based on the cost of solar ownership. The solar installation thereby provides a hedge value for the solar owner.[29]
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> The remaining load does not experience a reduction in volatility as a result of the solar installation. Behind-the-meter solar does not become part of the utility's resource portfolio. Rather, behind-the-meter solar functions like direct access, in which the load is separated from the remaining bundled customers and served with a third-party resource, i.e., a resource that is outside the utility's portfolio. Since the utility does not own or contract directly with the solar PV resource, the utility therefore will need to continue to hedge any market transactions for the remaining load in the same proportion as if the solar installation had not occurred. As a result, the hedge value accrues to the system owner, and the remaining utility ratepayers do not experience a reduction in bill volatility.[30]

Because the Commission adopted an RVOS Methodology that excludes values that accrue to the generation owner rather than ratepayers in general, OSEIA's proposal to include a hedging value related to reduced price volatility for this iteration of the RVOS Methodology should be rejected. However, Staff will explore whether it is appropriate to include both the hedge value and avoided hedge value in the RVOS calculation when the solar generation at issue is not behind-the-meter.

I. Updates to RVOS.

Staff recommends annual updates and identifies at least two options for annual updates. Under the first option, the updates could be tied to updates to avoided cost prices. Meaning, the utilities could be required to file updated RVOS values within a

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[29] Attachment, UM 1716 Staff/401, Olson/ (Staff Response to TASC DR No. 20).

[30] Attachment, UM 1716 Staff/401, Olson/ (Staff Response to TASC DR No. 20).

certain interval after acknowledgment of a utility's IRP and on May 1 of each year. The drawback of this approach is the additional workload on utilities, Staff, and stakeholders already working to develop avoided cost prices on a relatively compressed time period. Also, tying the RVOS Updates to IRP acknowledgment lessens the predictability of the timing of some of the updates.

The second option is to require the utilities to only file annual updates on a designated date. Under this option, the utilities would still incorporate information from their most recently acknowledged IRPs and acknowledged IRP Updates, but the acknowledgments would possibly have been several months prior. The drawback of this option is that the information could be more stale than in the first option. The benefit of this option is that it would provide stakeholders in the solar development community more predictability regarding the timing of RVOS price updates.

J. Utility scale alternative.

Staff believes there are too many issues related to the utility-proposed alternate utility-scale methods of valuing RVOS to seriously consider implementing these methods at this time.[31]

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[31] See Opening Brief of Renewable Northwest, pp. 9-10; OSEIA/100, OSEIA/100, Beach/40-42.

K. Conclusion.

Staff's opening brief includes a summary of recommendations from Staff testimony filed in this docket. These recommendations remain unchanged.

DATED this 9th day of August 2018.

Respectfully submitted,

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