PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

June 30, 2016

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

RE: UM 1716 —PacifiCorp's Reply Testimony

PacifiCorp d/b/a Pacific Power encloses for filing in the above-referenced docket its Reply Testimony.

If you have questions about this filing, please contact Natasha Siores at (503) 813-6583.

Sincerely,

R Bryce Dalley /ncs

R. Bryce Dalley
Vice President, Regulation

Enclosures

Docket No. UM 1716
Exhibit PAC/100
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Brian S. Dickman

June 2016

TABLE OF CONTENTS

Attached Exhibits

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs and Load Forecasting.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Before joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing. I have been employed by the Company since 2003, including positions in revenue requirement and regulatory affairs. I assumed my current role directing the Company's net power cost and load forecast groups in April 2015.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses the importance of adopting a standard methodology for calculating the resource value of solar (RVOS) for distributed solar resources that interact with PacifiCorp's distribution system. I also respond to certain policy issues raised in the Direct Testimony of Staff witness Ms. Cindy Dolezel associated with establishing a RVOS methodology, such as how the RVOS should be used and the importance of ensuring that the calculation of the individual inputs within the elements of the RVOS methodology creates results that are fair to all utility customers, both those customers employing distributed solar resources (i.e., private generation) and those that are not.

I also respond to the proposed RVOS method presented in the Direct Testimony of Mr. Arne Olson. Specifically, I address:

- The use of time- and area-specific marginal costs;
- The proposed elements for inclusion in the RVOS method;
- The calculation of several of the elements included in the proposed RVOS method; and
- Distribution resource planning and utility-scale solar as it relates to the RVOS methodology.

Q. Why is determining the RVOS critical at this time?

A. This phase of docket UM 1716 is the culmination of several years of investigation into the effectiveness of solar programs in Oregon. As part of the Commission's evaluation of solar programs in the state, a key inquiry has been how to properly value distributed solar resources, particularly in the context of Oregon's net metering program. As the Company sees increased penetration of net metered solar resources in Oregon, determining the appropriate methodology for valuing these solar resources is critical to ensure solar generation is compensated appropriately based on how these resources interact with the PacifiCorp distribution system and the Company's broader resource planning. If improperly valued, the end result is a potential shifting of a utility's fixed and other costs between customers deploying rooftop solar and those customers that are choosing not to deploy rooftop solar. There are ongoing debates in other jurisdictions on these very issues and Oregon has the opportunity now to establish a thoughtful methodology that strikes the balance between ensuring rooftop solar customers are fairly compensated for the value of the resource they provide to the utility and ensuring that costs in supporting that distributed resource are not being shifted to other customers that have chosen not to install private generation.

In addition, determining an appropriate methodology for calculating the RVOS will support recently passed legislation that directs the Commission to implement community solar programs for Oregon's three investor-owned utilities. Consistent with the Commission's recommendations to the legislature at the conclusion of docket UM 1746, Senate Bill (SB) 1547 requires utilities to compensate community solar participants for their share of the community solar generation "in a manner that reflects the resource value of solar energy."[1]

Q. Does PacifiCorp support the RVOS methodology proposed by Staff?

A. PacifiCorp commends Staff for developing a collaborative process throughout the many phases of this proceeding. In general PacifiCorp does not object to the elements identified by Commission Staff for calculating a RVOS for distributed rooftop solar installations, in that the elements consider RVOS from the perspective of utility customers. However, PacifiCorp does not at this time have sufficient information from Staff's testimony[2] to evaluate each of the specific calculations included in the broader RVOS methodology. For example, Staff's testimony provides assumed values for hedging and market price response to solar generation, but provides no details on how the values were calculated. Accordingly, while PacifiCorp generally does not oppose the elements included in the RVOS

[1] The Commission may, for good cause, adopt a rate other than the resource value of solar.
[2] For simplicity's sake, when I refer in my testimony to "Commission Staff's testimony," I am referring collectively to the testimony of Ms. Dolezel and Mr. Olson.

methodology proposed by Staff, a critical next step will be determining the appropriate calculation of each element of the broader RVOS methodology.

Q. How should the RVOS methodology be used?

A. The RVOS methodology should be used to determine the appropriate compensation for distributed solar resources. Methodologies already exist for calculating the costs of other types of solar resources (e.g., the Commission's avoided cost methodology for qualifying facilities) and the RVOS methodology should not be used in lieu of those existing methodologies. In addition, the RVOS methodology should be a flexible tool that takes into account the information currently available by each individual utility and can be tailored to fit the specific circumstances surrounding the need for a methodology that calculates a solar value. A key benefit to development of a methodology with discrete elements is that a solar value can be calculated even if each element contemplated within the methodology is not utilized due to its inapplicability in a certain circumstance.

Q. Can you provide an example of why the RVOS methodology would be used without all the proposed elements?

A. Yes. An example of employing the RVOS methodology without all of the proposed elements is the potential value of a solar resource based on its ability to defer transmission and distribution investment. As Ms. Dolezel and Mr. Olson note, such value is highly dependent on both location of the solar resource and to what extent transmission and distribution system investment in a given area is truly deferrable by installation of a distributed solar resource (e.g., whether the transmission and distribution system investments in an area are load growth-driven or required for others reasons that are not impacted by installation of a distributed solar resource). In this regard it should be acknowledged that each utility does not necessarily collect and maintain all the inputs that could be considered in the methodology, or at least not at the most granular levels identified by Mr. Olson in his testimony.

In addition to the above example with the limited application of a transmission and distribution system deferral benefit, other elements of the proposed RVOS methodology may also be inapplicable for any given utility. For example, PacifiCorp currently incurs no monetary cost of carbon for environmental compliance, so this element should either be excluded or set to zero.

Q. How often should the RVOS methodology be updated?

A. Ms. Dolezel recommends that the RVOS methodolgoy be updated every two years as a way to keep the methodology current with market trends and utility IRPs.[3] Refreshing the RVOS methodology and the calculation of the utility-specific RVOS and inputs are necessary to generate an accurate RVOS. PacifiCorp does not oppose reviewing the RVOS methodology every two years, but clarifies that the calculation of the utility-specific RVOS and inputs should be updated more frequently and as often as necessary to reflect current market conditions and distribution system characteristics. To the greatest extent possible, PacifiCorp would prefer to minimize the potential maximum period that customers would be held to a methodology that is relying on stale information and improperly valuing distributed solar resources.

Q. Did the scope of this phase of UM 1716 guide your review of Mr. Olson's testimony?

A. Yes. It is my understanding that in this phase of UM 1716, the methodology,

[3] Staff/100, Dolezel/9.

including the elements included in the methodology, are at issue. My understanding is that there will be a subsequent proceeding or phase of this proceeding to address utility-specific application of the methodology.[4] During this subsequent phase, I expect that issues associated with the specific inputs used in the calculation of the RVOS will be addressed.

MARGINAL COSTS

Q. Do you agree that time- and area-specific marginal costing is the appropriate framework for analyzing the RVOS?

A. Yes. As described by Mr. Olson, time- and area- specific marginal costing recognizes differences in the value of generation at different times and locations. He describes that "short-term impacts include changes to the operation of electric generators" and "longer-term impacts include potential changes to the schedule of capital investments."[5] Capturing the relative value difference due to time and location at which the generation occurs is important when measuring the value of distributed solar resources across PacifiCorp's service territory.

Q. Does PacifiCorp have experience calculating marginal costs that are time-and location-specific?

A. Yes. For many years the Company has used its Generation and Regulation Initiative Decision Tools (GRID) production cost model to calculate the marginal, or avoided, cost of incremental resources or load on its system. In Oregon, GRID has been used to value reductions in load due to customers departing under direct access programs

[4] *Investigation to Determine Resource Value of Solar,* Docket UM 1716, Order No. 15-296 at 2 (Sept. 28, 2015).
[5] Staff/200, Olson/7.

and has recently been approved[6] for use in calculating the avoided cost of non-standard qualifying facility (QF) generators desiring to deliver output to PacifiCorp's system in Oregon. In Order No. 16-174 the Commission stated, "[w]e agree this GRID model-based method more accurately values energy and capacity on PacifiCorp's system by taking into account the unique characteristics (including location, delivery pattern, and capacity contribution) of each QF."[7] Later in my testimony I describe how a GRID model approach can be used in conjunction with Staff's proposed RVOS framework.

Q. Are there limitations when calculating time- and area-specific marginal, or avoided, costs?

A. Yes. As described by Mr. Olson, the accuracy of an hourly, location-specific, RVOS calculation depends on the availability of utility data at a sufficient level of granularity (both on the basis of time and location). Mr. Olson acknowledges that Oregon utilities currently do not have granular data available for many of the proposed RVOS elements.[8] When detailed data is not available, higher-level information must instead be used with assumptions required to fit the available data into an hourly RVOS methodology. The GRID model, for example, is currently configured to divide the Company's Oregon service territory into several generalized areas, primarily designed to recognize the location of supply-side resources and aggregate load areas, connected with limited transmission capacity. This model design provides reasonable marginal cost results while balancing the need to capture

[6] In the Matter of Public Utility Commission of Oregon, Investigation into Qualifying Facility Contracting and Pricing, UM 1610, Order No. 16-174.
[7] Order No. 16-174 at 23.
[8] Staff/200, Olson/12.

major system constraints with the additional complexity that comes from collecting and utilizing more granular information.

More importantly, it is critical to recognize that calculating a long-term projection of avoided costs using point estimates at a specific point in time requires assumptions about the future that introduce a significant amount of uncertainty regarding the accuracy of the projected costs. History has proven that such forecasts often fail to keep up with market changes, and locking in fixed prices for private solar sold under net metering based on long-term forecasts risks compensating one class of customers at the expense of others. From Staff's testimony it is not clear how they intend to utilize the calculated RVOS. Mr. Olson's methodology is designed to calculate an annual stream of nominal marginal costs, but in several places in his testimony[9] and in the methodology he presents values levelized over a period of 25 years.

Q. Is 25 years an appropriate term for levelization of the RVOS?

A. No. The longer the period of levelization for the RVOS, the more customers bear the risk of locking in a RVOS that, over time, becomes stale as market conditions change or the utility resource position changes. As Mr. Olson acknowledges, the RVOS "will need to be updated regularly as market conditions change or utility resource plans change."[10] Mr. Olson also makes clear that certain values, such as the generation capacity value, are "strongly affected" by the utility resource sufficiency or deficiency.[11] Locking in RVOS prices over a 25-year term undermines the

[9] Staff/200, Olson/27, 41-42.
[10] Staff/200, Olson/44.
[11] Staff/200, Olson/27.

objective of keeping the RVOS closely aligned with market conditions and changes in utility resource need.

Avoided cost prices in Oregon Schedule 37 and Schedule 38 are available to QFs for up to a 20-year term, but prices can only be locked in for the first 15 years, and QFs cannot receive a levelized price over the term of the contract. While longer term contracts are available to QFs, the QF contract include credit terms, security deposits, performance guarantees, liquidated damages, default provisions, and termination rights that are not found in arrangements between the utility and customers with net-metered private generation. Those contractual terms protect the utility and its customers from non-performance and are essential to mitigating the risks associated with long-term contracts. Since these protective contract terms are not available to the Company for customers with private generation, shorter term valuations are appropriate.

RVOS ELEMENTS

Q. Please describe the elements Mr. Olson proposes to include in the RVOS methodology.

A. Mr. Olson proposes the following 10 elements for inclusion in the RVOS methodology:

- Energy
- Generation Capacity
- Line Losses
- Transmission and Distribution Capacity
- Renewable Portfolio Standard (RPS) Compliance

- Integration[12]
- Administration[13]
- Market Price Response
- Hedging Costs
- Environmental Compliance

Q. Are these elements appropriately included in the RVOS calculation?

A. PacifiCorp generally does not oppose the elements proposed by Staff, in that these elements are intended to consider RVOS from the perspective of a utility customer, but the Company proposes modifications to the definitions provided by Staff. Attached to my testimony as Exhibit PAC/101 is a table, similar to Table 2 in Mr. Olson's testimony, that shows Staff's definitions of the 10 elements along with PacifiCorp's proposed changes to the definitions. PacifiCorp further notes that the critical next step will be determining the appropriate inputs and specific calculation for each element of the RVOS methodology. Until the specific calculations for each element of the RVOS methodology are known, the Company is limited to commenting on the definitions of the elements and the high-level calculations provided by Mr. Olson. Several of the elements proposed by staff include unspecified or unsupported calculations that are applied in the generic example calculation provided by Mr. Olson. The Company expects that as each utility begins to implement the RVOS, issues will arise that will require solutions specific to each company, including potentially excluding a given element or setting it to zero if it is not applicable to the Company.

[12] PacifiCorp does not propose any changes to the integration element proposed by Mr. Olson.
[13] PacifiCorp does not propose any changes to the administration element proposed by Mr. Olson.

RVOS METHODOLOGY AND CALCULATION

Q. Please describe Staff's proposed method for determining the RVOS.

A. To determine the RVOS, Mr. Olson developed a methodology that calculates the hourly marginal avoided cost (or incremental cost) associated with each of the above elements which is aggregated to arrive at the RVOS. Mr. Olson provided the following formula:

$$\forall h \in [1, \ldots, 8760]$$

$$\begin{aligned} Value_h = {} & Energy_h \\ & + Generation\ Capacity_h \\ & + Line\ Losses_h \\ & + T\&D\ Capacity_h \\ & + RPS\ Compliance_h \\ & + Market\ Price\ Response_h \\ & + Hedge_h \\ & - Integration_h \\ & + Environmental\ Compliance_h \\ & - Administration_h \end{aligned}$$

Q. Do you agree with the proposed calculation methodology for the RVOS elements as defined in Table 3 of Mr. Olson's testimony?

A. The Company believes the calculations provided in Table 3 of Mr. Olson's testimony are a reasonable starting point from which to determine the RVOS for each utility. However, as stated above, several of the specific calculation methods proposed are unsupported by any details or supporting calculations. I provide some clarifying points for several of the elements below.

- *Energy* – PacifiCorp recommends calculating the marginal cost of energy using a production cost modeling approach that measures the impact of solar generation on the Company's system. The Company routinely utilizes its GRID model for similar purposes in other venues, and it would be appropriate to use for the RVOS calculation. Using GRID provides several benefits, including the ability to calculate the hourly impact that incremental solar generation would have on existing and planned supply-side resources and system balancing transactions in the wholesale market. The model accounts for the location-specific value of solar resources by recognizing varying generation profiles as well as known transmission constraints. Calculation of the marginal avoided energy cost begins with a base model run that includes the Company's existing and planned resource portfolio and access to wholesale markets. The net power costs (sum of fuel, purchased power, and wheeling expenses, less revenue from wholesale sales) from this base portfolio are compared to the net power costs from a second model run that includes the solar resource generation. The second model run would capture the incremental impact of reducing generation on existing facilities as well as the impact on energy costs related to deferring a portion of a planned resource addition (an item Mr. Olson included in his calculation of the marginal cost of Generation Capacity).

- *Generation Capacity* – The Company agrees with Mr. Olson that the carrying cost of new generation capacity should be included only during periods of resource deficiency.[14] Currently, the concept of resource deficiency is used when computing avoided costs for PURPA QFs. In the case of QF avoided costs, the next major thermal resource acquisition in the Company's latest Integrated Resource Plan is used to identify the deficiency period. The resource deficiency period for the RVOS should be determined consistent with the methodology, including any changes or updates to the methodology, used to determine resource deficiency for QF avoided costs. Mr. Olson identifies that the capacity costs would be net of expected energy market revenue—if a GRID model approach is used to calculate the marginal cost of energy as described above, the marginal energy costs would already capture the ability of that capacity resource to be dispatched into the market, as well as any reduction in market sales related to the deferral of such capacity, and no additional adjustment would be needed. In Table 3 of Mr. Olson's testimony he states, "…when the utility is not in a period of resource deficiency a value of zero is used since there are no deferrable capacity investments." However, in his generic example, Mr. Olson includes fixed operations and maintenance costs as avoided capacity costs. The Company believes this cost should be zero because there would not be avoided capacity costs on existing capacity resources during periods of resource sufficiency.
- *Transmission and Distribution Capacity* – As explained by Mr. Olson, transmission and distribution capacity should be limited to the deferral of

[14] Staff/200, Olson/30.

expanding capacity due to load growth, and it is possible that there would be no deferral.[15] In addition, to the extent the RVOS methodology takes into account deferred transmission and distribution investments, a symmetrical component of the calculation should be included: costs associated with accelerated transmission and distribution investments. This symmetry is necessary to ensure that distributed generators are accurately compensated and utility ratepayers are not unduly harmed. Based on the information provided in Staff's testimony, it is not clear whether these symmetrical elements are included in the calculation of transmission and distribution margin.

- *RPS Compliance* – With respect to RPS Compliance, to the extent distributed solar generation does not provide the utility with RPS value, the value should be zero. This could be the case if, for example, the generation does not directly offset retail load (i.e. net metering) and the utility does not receive the renewable energy certificates (RECs) associated with the solar generation. In addition, the RPS Compliance element should not, at this time, include an avoided emissions value consistent with the Environmental Compliance element below.
- *Market Price Response* – Staff's proposed method to include a market price response is based on an assumed change in the Mid-Columbia market price due to solar, but it is unclear how such a change will be determined. Staff's testimony provides no explanation or details describing how this calculation was made, or support for a method to determine the impact that output from customers' private solar generation could have on a liquid market such as the

[15] Staff/100, Olson/10.

Mid-Columbia. In the RVOS methodology, Mr. Olson assumes that market prices will fall an average of $0.096 per MWh, but provides no supporting documentation. Full vetting of the calculation of the change in the Mid-Columbia market price due to solar should occur prior to its inclusion as an element of the ROVS.

- *Hedge Value* – Mr. Olson proposes a hedge value equal to a fixed percentage of the energy costs, but provides no rationale or support for this approach.[16] Then in the RVOS methodology Mr. Olson sets the percentage at five percent of energy costs.[17] The determination of hedging costs will certainly be specific to each utility and will depend on the nature and extent of that company's hedging program. While PacifiCorp is not opposed to recognizing hedging costs of some kind, such as the transactional costs associated with hedging, it does not make sense to apply a fixed percentage to an energy value determined by reductions in costs of fuel, transportation, variable operations and maintenance, labor, and other variable costs (either as determined by Mr. Olson or using a GRID model approach to valuing energy costs).
- *Environmental Compliance* –Including a calculation of avoided environmental compliance costs is only appropriate for the RVOS methodology to the extent environmental compliance obligations are actually imposed and quantifiable costs are actually avoided. Staff's RVOS methodology includes an avoided cost of carbon emissions equal to $10 per ton in 2016 and escalating into the future. PacifiCorp is not yet subject to regulation that imposes a cost on

[16] Staff/200, Olson/33.
[17] Staff/200, Olson/43.

carbon emissions, although the Company recognizes the potential for the eventual imposition of carbon costs. Until private solar generation actually avoids a carbon cost this element should either be eliminated or determined to be zero.

Attached to my testimony as Exhibit PAC/102 is a table, similar to Table 3 in Mr. Olson's testimony, that summarizes PacifiCorp's comments and proposed changes to the calculation of each element.

Q. Mr. Olson anticipates that utility data will be available at an hourly level of granularity for use in the RVOS methodology. Does PacifiCorp have all of the required data inputs at an hourly level of granularity?

A. No. Several of the inputs to the RVOS methodology are available on an hourly basis, such as the solar generation profile and modeled avoided energy costs, but several of the proposed elements are not. As Mr. Olson acknowledges the utilities do not have hourly levels of granularity for each element and notes that "[i]n cases where utilities do not have hourly values, a single value can be duplicated over many hours.[18] For example, Mr. Olson proposes to spread avoided capacity costs across the hours of a year based on a utility loss of load probability (LOLP) study. The Company agrees that, to the extent possible, an hourly level of data granularity should be used but, in instances where hourly data is not available, an accurate RVOS can still be achieved.

[18] Staff/200, Olson/29.

DISTRIBUTION PLANNING

Q. Mr. Olson indicates that location-specific distribution system planning is expected to "provide valuable information about where distributed energy resources can be targeted to achieve the highest value."[19] Does PacifiCorp currently conduct location-specific distribution system planning?

A. Yes, to a certain extent. Slightly less than half of PacifiCorp's Oregon distribution circuits have the supervisory control or data acquisition capabilities necessary to acquire the data needed to perform the type of location-specific distribution system planning referenced by Mr. Olson. PacifiCorp continues to develop strategies to improve its ability to achieve location-specific distribution system planning, and points out that automated metering infrastructure will be installed in Oregon by 2020. This will increase PacifiCorp's ability to conduct more in-depth analysis of the location-specific costs and benefits associated with distributed solar generation.

Q. Does this conclude your reply testimony?

A. Yes.

---

[19] Staff/200, Olson/12.

Docket No. UM 1716
Exhibit PAC/101
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

PacifiCorp's Proposed Changes to Staff's Definitions of RVOS Elements

June 2016

EXHIBIT PAC/101

Element of Value	Definition (Staff Proposal)	Definition (PacifiCorp Proposal)[1]
Energy	Marginal avoided cost of purchasing or selling electricity into the wholesale market. – OR – Marginal avoided cost of producing energy from conventional wholesale generating resources including the cost of fuel (and associated transportation costs), variable operations and maintenance, labor, and all other variable cost.	Marginal avoided cost of production on utility's system, including cost of energy from conventional generation as well as purchasing or selling electricity into the wholesale market.
Generation Capacity	Marginal avoided cost of building and maintaining the lowest net cost generation capacity resource.	No changes at this time.
Line Losses	Avoided marginal electricity losses from the point of generation to the point of delivery.	Avoided marginal electricity losses from the point of generation to the point of delivery or other loss factors that are available for either the primary, secondary or transmission voltage levels depending upon circumstance.
Transmission and Distribution Capacity	Avoided or deferred costs of expanding, replacing, or upgrading transmission and distribution infrastructure such as substations, lines, and transformers.	Avoided, deferred, or increased costs, of expanding, replacing, or upgrading transmission and distribution infrastructure such as substations, lines, and transformers.
RPS Compliance	Avoided incremental cost of purchasing renewable energy to satisfy the Oregon RPS	No changes at this time.

[1] To the extent PacifiCorp does not recommend a specific change to the definition, PacifiCorp reserves the right to recommend changes to this definition in subsequent stages of this proceeding.

	requirement. The incremental cost is defined as the levelized cost of a renewable resource less the value of that resource provides from energy, capacity, and environmental compliance plus the cost of that resource due to renewable integration.	
Integration	Increased costs associated with integrating solar PV into the electrical system. These costs include additional spinning reserve and ancillary service requirements necessary to facilitate the variability and intermittency of solar PV production, as well as any change in ancillary service procurement due to reduction in metered load.	No changes at this time.
Administration	Increased costs to administer distributed solar PV programs such as net energy metering (NEM). This includes the cost of additional utility staff, incremental billing software, incremental costs of interconnection and any other utility-specific costs. Incremental costs of interconnection are defined as the total cost of interconnection less the portion of this cost paid by the interconnecting solar generator.	No changes at this time.
Market Price Response	The change in utility costs due to lower wholesale energy market prices caused by increased solar PV production, affecting the price at which the utility transacts in the wholesale market when managing its portfolio of resources on behalf of its retail	Requires further support from Staff to determine how solar production impacts wholesale energy market prices.

	customers. Lower market prices result in lower costs for utility market purchases, but reduced margins for utility market sales. The net effect on the utility could be either positive or negative, depending on the relative magnitude and timing of market purchases and sales. Lower market prices are not a societal benefit, because they represent a transfer of wealth from one member of society (electricity producers) to another member (electricity consumers).	
Hedging Costs	Avoided cost of utility fuel cost hedging activities, i.e., transactions intended solely to provide a more stable retail rate over time. Solar generators may experience additional hedging value due to more stable electricity costs.	No changes at this time.
Environmental Compliance	Avoided cost of complying with existing and anticipated carbon standards due to a reduction in carbon emissions from the marginal generating unit. The cost of compliance with criteria pollution regulations is assumed to be captured in the avoided cost of generation capacity.	Avoided cost of complying with existing carbon standards due to a reduction in carbon emissions from the marginal generating unit. If there are no enforceable carbon standards, this element should be excluded or set to zero.

Docket No. UM 1716
Exhibit PAC/102
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

PacifiCorp's Comments and Proposed Changes to Elements of Avoided Cost Calculation Methodology

June 2016

EXHIBIT PAC/102

RVOS Element	Staff Proposed Calculation Methodology	PacifiCorp Proposed Calculation Methodology[1]
Energy	Hourly marginal cost of energy including fuel (and associated fuel transportation costs), variable operations and maintenance, labor, and all other variable costs.	Hourly marginal cost of energy as calculated by a production cost model with and without distributed solar resources, including partial displacement (deferral) the next major thermal resource acquisition in the utility's Integrated Resource Plan (IRP).
Generation Capacity	Annual carrying cost of new generation capacity ($/MW-yr) allocated to hours of the year using hourly normalized capacity value allocators. The allocators represent an hourly system need profile (based on loss of load probability (LOLP) or another method), multiplied by the modeled hourly solar generation, and scaled so that the allocators sum to one across the hours of the year. Annual carrying cost of new generation capacity ($/MW-yr) is defined as net cost of new entry (net CONE). Net CONE is calculated as the levelized carrying cost of a capacity resource – the levelized fixed cost of the resource (likely a new simple cycle combustion turbine (SCCT)) minus expected revenues that resource could earn through market dispatch. In the near-term years when the utility is not in a period of	Annual carrying cost of new generation capacity ($/MW-yr), adjusted for solar's contribution to peak, allocated to hours of the year using hourly normalized capacity value allocators. Annual carrying cost of new generation capacity is equal to the cost of the next major resource acquisition in the utility's IRP. In the near-term years when the utility is not in a period of resource deficiency, a value of zero is used since there are no deferrable capacity investments.

[1] To the extent PacifiCorp does not make a specific recommendation on the calculation methodology, PacifiCorp reserves the right to recommend changes to the calculation methodology in subsequent stages of this proceeding.

	resource deficiency, a value of zero is used since there are no deferrable capacity investments. Solar's contribution to peak is a technical concept that captures solar's ability to serve peak loads. Through OPUC Docket UM 1719, the utilities have worked to develop a methodology for calculating this value. Many utilities across the country use a metric called effective load carrying capability (ELCC) to calculate the contribution to peak. The hourly capacity allocators (net CONE, allocated using LOLP) are scaled to ensure that the final generation capacity value of solar results are consistent with the utility-estimated solar contribution to peak.	
Line Losses	Hourly marginal T&D loss factors multiplied to corresponding avoided cost of energy. For generation capacity and transmission & distribution capacity, these values are grossed up based on peak marginal T&D loss factors.	No changes at this time.
Transmission and Distribution Capacity	Marginal cost of transmission and distribution ($/MW-yr) allocated to hours of the year using transmission and distribution specific hourly profiles (perhaps based on LOLP).	Avoided and incremental cost of transmission and distribution ($/MW-yr) allocated to hours of the year using transmission and distribution specific hourly profiles.
RPS Compliance	The net incremental cost of a renewable resource multiplied by the RPS requirement. The net incremental cost of a renewable resource is	The net incremental cost of a renewable resource multiplied by the RPS requirement. The net incremental cost of a renewable resource is

	calculated as the levelized cost of the marginal renewable resource minus its energy value, generation capacity value, and avoided emission value plus the integration and transmission costs of that resource. The RPS requirement (%) is incorporated since this represents the quantity of RPS purchases that are avoided for every unit of solar generation.	calculated as the levelized cost of the marginal renewable resource minus its energy value, generation capacity value, plus the integration and transmission costs of that resource. The RPS requirement (%) is incorporated since this represents the quantity of RPS purchases that are avoided for every unit of solar generation. The calculation should not include an avoided emission value unless there is a direct emissions cost.
Integration and Ancillary Services	$/MWh value provided by utilities that represents the net incremental cost of providing additional operating reserves, balancing services, and system operations required to integrate the solar resource.	No changes at this time.
Administration	$/MWh value provided by utility that represents the cost of interconnecting solar generators and any ongoing administrative costs such as billing. This value is uniform across all hours of the year.	No changes at this time.
Market Price Response	Estimated impact on Mid-Columbia price under a specified solar penetration ($/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.	Requires further support from Staff to determine how solar production impacts wholesale energy market prices. No method was provided by Staff to calculate the impact on market prices due to solar. To the extent there is a reasonable method for calculating this value, it should only be applicable if the value is not already

		captured in energy marginal costs.
Hedge Value	Fixed % multiplied by the avoided cost of energy that represents the cost of utility hedging that is not already included in the energy value estimate described above.	Utility-specific cost of hedging determined based on transactional costs.
Environmental Compliance	Hourly marginal emission factor of carbon dioxide multiplied by the monetary cost of carbon dioxide.	If there is no monetary cost of carbon dioxide incurred or avoided by the utility, this element should be excluded or set to zero.