CASE: UM 1910/1911/1912
WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

March 16, 2018

SECTION 1: INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Brittany Andrus. I am a senior utility analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please explain the purpose of this testimony.

A. Staff addresses the Resource Value of Solar (RVOS) filings made by PacifiCorp, Idaho Power Company (Idaho Power), and Portland General Electric Company (PGE) to start Phase II of the Commission's Investigation into the Resource Value of Solar (RVOS) (Docket No. UM 1716).

Q. How is your testimony organized?

A. In Section 1, Staff provides a brief background of Phase I of the Commission's Investigation into the RVOS. Staff identifies the elements of solar generation that the Commission decided to include in the RVOS as well as the valuation methodology adopted by the Commission at the conclusion of Phase I in Order No. 17-357 ("Phase I RVOS Methodology" or "Methodology").

In Section 2, Staff analyzes each utility's implementation of the Phase I RVOS Methodology. Staff begins by summarizing the values provided by PacifiCorp, PGE and Idaho Power, drawing attention to the fact that PacifiCorp has reported the RVOS in "nominal levelized" dollars rather than "real levelized" dollars as contemplated by the Methodology and done by PGE and Idaho Power. Staff then analyzes each utility's implementation of the

Methodology, element by element. For each of the RVOS elements, Staff provides the following:

1. Summary of the Commission's directions on the element.
2. Brief description of how each utility implemented the Phase I RVOS Methodology.
3. Opinion on whether the utility's implementation comports with the requirements of Order No. 17-357 and if the utility used a different approach, a description of the utility's approach and whether it is reasonable.

If applicable, Staff also provides its recommendation for refinement to the Methodology.

In Section 3, Staff addresses issues that are not specific to an individual RVOS element, including Staff's position on the frequency of RVOS updates. Staff also addresses the values for utility scale solar facilities that have been provided by each utility.

In Section 4, Staff summarizes its recommendations regarding refinements to the Phase I RVOS Methodology.

Q. Is this the only testimony Staff provides in this docket?

A. No. In Staff Exhibit 200, Staff addresses the RVOS values provided in the utility filing in this docket and discusses the utility's implementation of the Methodology. In Staff Exhibit 200, Staff will make recommendations on how each utility should change its implementation of the Methodology if Staff finds the implementation does not conform to Order No. 17-357.

Staff Exhibit 100 will be identical in each of the three dockets opened for Phase II of the Commission's investigation into RVOS (Docket Nos. UM 1910/1911/1912). Staff Exhibit 200 will be specific to one utility and that utility's implementation of the Commission's Methodology.

Q. Please summarize the background of this docket.

A. The three dockets opened for the utilities' RVOS filings are the second phase of the Commission's investigation into RVOS. In Phase I, the Commission determined the aspects (elements) of solar generation that would be valued for purposes of determining the RVOS. The Commission determined that only elements that provide value, or are costs, to the utility and ratepayers would be included in RVOS. These elements are energy, generation capacity, transmission and distribution capacity, line losses, integration, administration, hedge value, market price response, environmental compliance, grid services, and Renewable Portfolio Standard (RPS) compliance. The Commission determined that other aspects of solar generation, those that provide value to the generator or society in general, are not included in the RVOS.

At the conclusion of Phase I, the Commission adopted the Phase I RVOS Methodology, which is the RVOS methodology developed and presented by the expert witness retained by Staff, Energy + Environmental Economics (E3), but with some modifications and placeholders. The Commission ordered PacifiCorp, PGE, and Idaho Power to develop initial RVOS calculations based on its Phase I RVOS Methodology and submit them in new utility-specific dockets no later than November 30, 2017. The Commission noted that it intended for parties to build a robust record to support the Commission's final determination of RVOS for each utility.

The Commission's Phase I order makes clear that the Commission will make some refinements to the Phase I RVOS methodology, possibly as soon as the Phase II final order. For example, while the Commission instructed utilities to include a placeholder value of zero for RPS compliance, the Commission stated that it intended to assign a methodology before the end of Phase II.

Regarding the valuation of other elements, the Commission noted that some refinement to the Methodology may be made in the future, but did not impose a specific timeline for these refinements. Accordingly, Staff examined the utilities' filings in Phase II to determine not only whether the utilities complied with the methodology adopted at the conclusion of Phase I, but also whether the filings proposed refinements to the Methodology that the Commission should adopt or investigate.

Each of the utilities provide insight into potential improvements to the modeling and have opined on instances in which the incremental benefits obtained by additional granularity or refinement are not worth the considerable investment of resources needed to obtain the granularity. However, Staff does not believe any of the refinements identified by the utilities should be implemented immediately. Instead, Staff suggests further consideration of the proposals and ideas in the future.

SECTION 2: STAFF ANALYSIS OF UTILITY IMPLEMENTATION

PHASE II RVOS VALUES SUMMARY

Q. What values did the utilities provide for RVOS?

A. The values provided by the utilities are set forth below.

Table 1. Standard Distributed Solar RVOS $/MWh

Element	**PacifiCorp** Nominal Levelized[1]	**PGE** Real Levelized	**Idaho Power** Real Levelized
Energy	$30.58	$24.98	$29.74
Generation capacity	12.20	7.30	15.3
T&D capacity	0.08	8.08	0.87
Line losses	1.96	1.48	2.54
Administration	-2.59[2] ~~2.88~~	-5.58	-47.77
Integration	-0.82	-0.83	-0.56
Market price response	0.15	1.81	0
Hedge value	1.54	1.25	1.49
Environmental compliance	0.11	11.41	0
RPS compliance	0	0	0
Grid services	0	0	0
Phase II RVOS Total[3]	$42.92	$49.88	$1.61

[1] PacifiCorp values based on December 21, 2018 errata filing.
[2] PacifiCorp response to CUB Data Request 4 ("Flowing this change in administrative costs through the resource value of solar (RVOS) model reduces the nominal levelized administrative cost from $2.88 per megawatt-hour ($/MWh) to $2.59/MWh.").
[3] Totals may not match due to rounding.

Notably, PacifiCorp diverged from the E3 methodology to report RVOS in nominal levelized dollars but Idaho Power and PGE used the E3 methodology to report RVOS in real levelized dollars.[4, 5]

RVOS METHODOLOGY

Q. Does Staff address the utilities' methodologies by element and in the order in which they are discussed and presented in the matrix attached to Order No. 17-357?

A. Staff addresses the utilities' methodologies element by element, but not in the order they are addressed in Order No. 17-357. Staff has grouped the elements into three categories.

The first category examines the elements that impact a utility system as a whole. This category, which Staff calls "System Elements," consists of energy, generation capacity, and integration. These elements add value, or cost, regardless of where they are located.

Elements in the second category also impact the utility system, but in a way that depends upon the location on that system. This category, which Staff refers to as "Location-Specific System Elements," includes transmission and distribution capacity, line losses, and grid services.

The third category consists of the elements that are *attributed to* the solar generation on the utility system. These values of solar generation are derived from regulations and laws and from market characteristics. Staff

[4] PacifiCorp's non-confidential workpapers in UM 1910.
[5] Note that the different values of "Market price effect" and "Avoided energy cost" reported by PacifiCorp in testimony are the result of after-model modifications by PacifiCorp.

calls this third category “Non-system Elements” because the attributes that have been assigned do not impact the utility’s physical system operations. This category includes administration, hedge value, market price response, environmental compliance and RPS compliance.

SYSTEM ELEMENTS

ELEMENT 1, ENERGY

Q. Please summarize the Commission’s (1) definition of energy, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: The marginal avoided cost of procuring or producing energy, including fuel, O&M, pipeline costs and all other variable costs.

Inputs from the Utilities: Utilities shall produce a 12 x 24 block for energy prices and include a detailed explanation of how they created the block. Utilities shall demonstrate through statistical analysis that their energy values are scaled to represent the average price under a range of hydro conditions.

Next Steps: The utilities shall propose this value in Phase II.[6]

Q. What energy values did the utilities submit?

A. The utilities’ energy RVOS values are presented in the table below. Two prices are provided for PacifiCorp in the introduction to each element as a way to provide comparability in real levelized dollars.

[6] The Commission’s definition, directions to utilities, and next steps for each element are taken from Commission Order No. 17-357.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$30.58	24.17	$24.98	$29.74

Q. How did Staff review the utility approaches to energy valuation?

A. For each utility, Staff reviewed the forward prices, the method used to shape the prices to the 12 x 24 block, and the method used to account for hydro variability. Staff also reviewed the shape of the solar resource generation used as the basis for calculating the energy value.

Market Prices and Shaping

Q. What forward prices did PacifiCorp use and how did PacifiCorp shape them?

A. PacifiCorp used the official forward price curves it uses for PURPA standard avoided cost prices. After calculating forward monthly on-and off-peak prices based on three market hubs (Mid-Columbia, Palo Verde, and California-Oregon Border), PacifiCorp shaped those prices to settlement prices from three load aggregation points (LAP) from the energy imbalance market (EIM) for the 12-month period ended September 2017.[7]

Q. Why did PacifiCorp choose this method?

[7] UM 1910 PAC/MacNeil/6-7, 12-16.

A. PacifiCorp states that it cannot use its hourly forward price profile to shape RVOS energy prices because it is based on proprietary data from Powerdex and PacifiCorp must keep the data confidential.[8]

Q. Does Staff believe settlement prices from the EIM provide an appropriate reference point for hourly shaping of prices?

A. No. While PacifiCorp conducts many transactions in the EIM, the majority of its wholesale transactions are not in that market. EIM settlement price shapes may inform the marginal energy, but Staff is not convinced that the EIM-based shape reflects the hourly energy value to the PacifiCorp system.

Q. If confidentiality requirements preclude the use of PacifiCorp's hourly forward price shape, and Staff does not support use of the EIM shape, what does Staff suggest as an alternative?

A. Staff does not have a proposal for an alternative. Staff is not opposed to including EIM values as part of the shaping algorithm, but Staff does not support using EIM settlement values as the sole shaping factor.

Q. What forward market prices did PGE use and how did PGE shape the energy prices?

A. PGE also used forward market prices that it uses for standard PURPA contracts. PGE created daily shape factor profiles for each month using hourly prices for 2024 produced by AURORA.[9] PGE calculated the average price for each month/hour by averaging the price of each daily hour in a given month, weighting the month/hour prices by the number of days in the

[8] UM 1910 PAC/MacNeil/13-14.
[9] UM 1912 PGE/200, Jordan/7-8.

month and dividing by the annual average price. PGE then applied the shape factors to the weighted average annual price (based on monthly prices discussed above) for each year to create daily prices profiles for each month of each year (or 12 x 24 blocks).[10]

Q. Does Staff believe that PGE's approach to the 12 x 24 shaping is reasonable?

A. Staff understands the reasoning behind the Aurora-based approach employed by PGE. However, in other dockets Staff has had issues with some aspects of the Aurora output as used for monthly energy prices,[11] and plans to further examine this component of the RVOS filing.

Q. What prices did Idaho Power use and how did Idaho Power shape them?

A. Idaho Power used the market prices used for its standard avoided cost prices and applied a price shape factor of one, resulting in a flat shape applied to the annual energy value.[12]

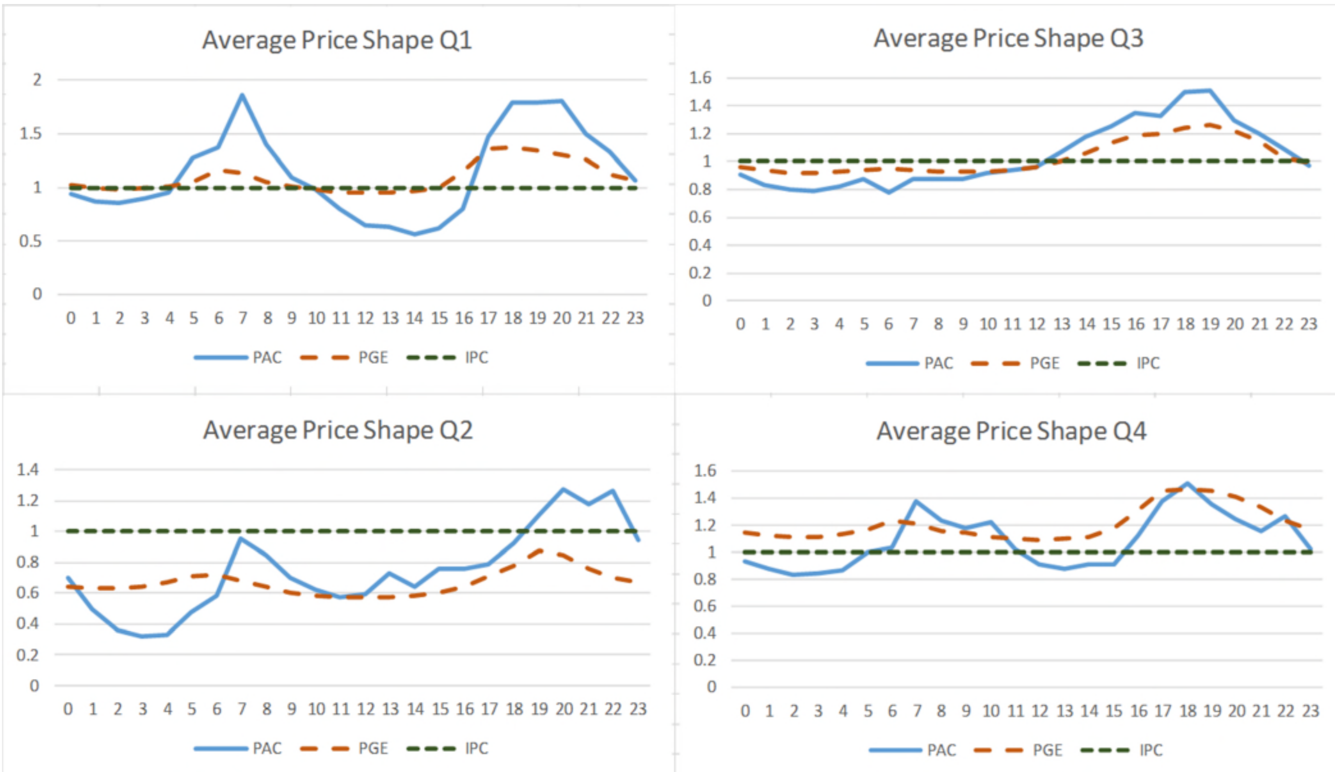
Q. Do Idaho Power's market prices and shaping comply with Order No. 17-357?

A. Staff does not believe that a flat hourly shape meets the requirements of Order No. 17-357. Staff recommends that Idaho Power propose a method to derive the 24-hour price shape for each month and apply it in the E3 model.

[10] UM 1912 PGE/200, Jordan/7-8.
[11] See Staff Report in Docket No. UM 1728, September 17, 2017.
[12] UM 1911 Idaho Power/100, Haener/5.

Q. What are the results of applying the three utilities' hourly shaping methods to monthly energy prices?

A. Staff provides quarterly comparisons of each utility's results in the four graphs below.



Q. Does Staff have any observations regarding the forward market price curves used by the utilities?

A. It is not clear from Order No. 17-357 whether the Commission intended for the utilities to use the exact same market prices for RVOS that are incorporated into the utilities' current standard avoided cost prices or merely to use the same source for forward price curves,

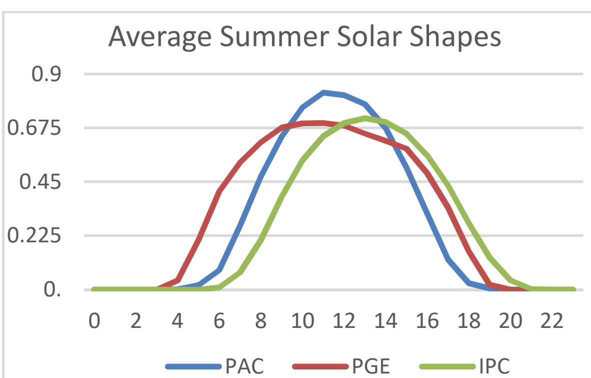
Staff believes that the utilities should use the same source of forward price curves that is used for their standard avoided cost prices, but does not see the value in the utilities using the same “vintage” of forward price curve that is used for standard avoided cost prices unless the timing of the RVOS filing is close in time to the utility’s filing of avoided costs.

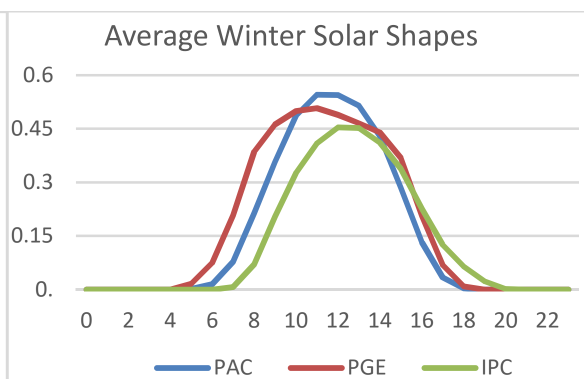
Staff recommends that the Commission clarify that the Phase I Methodology only requires the same source of forward market prices as is use for standard avoided cost prices and that the Commission expects utilities to use the most recent forward market price curve that is available at the time the RVOS filing is prepared.

<u>Solar Generation Shape</u>

Q. Please summarize Staff’s assessment of the utilities’ solar generation profiles.

A. In terms of the solar resource, Staff is satisfied that each utility chose a reasonable generation profile, shown for winter and summer months in the two graphs below.





<u>Hydro Variability</u>

Q. In Order No. 17-357 the Commission determined that the energy data input for future energy prices should reflect a distribution of potential

hydro conditions. What instructions did the Commission provide utilities and other parties for modeling a distribution of potential hydro conditions?

A. The Commission asked the utilities to include a narrative explanation as well as statistical analysis demonstrating how their energy values are scaled to represent the average price under a range of hydro conditions. The Commission also asked other parties to specifically respond to the utilities' analyses so that the Commission will have a full record to evaluate.

Q. How does Staff interpret the requirement that average price be represented under a range of hydro conditions?

A. In the Pacific Northwest hydro conditions are a fundamental market driver. As such, there are complex interactions between hydro conditions and market prices. In order to capture the complex relationships, market price should be calculated separately under representative random sample of hydro conditions. The average of the resulting market prices will provide an approximation of average market price under the entire distribution of hydro conditions.

Q. What type of statistical analysis could be performed to demonstrate that the average market price is representative?

A. The accuracy of Staff's proposed approach depends on the sample size. A larger sample size will result in a more accurate estimate of the average market price across the distribution of hydro conditions. One statistical analysis to evaluate whether the estimate is accurate is to construct a 95 percent confidence interval around the market price. This would allow the Commission to make a judgment about whether the estimate is sufficiently accurate.

Q. Please summarize Idaho Power's approach to hydro variability.

A. Idaho Power uses the following process:

- Select sample of five historic hydro years from 82 historic years. The sample uses the 10, 30, 50, 70, and 90 percentile years by stream flow.
- Perform one Aurora run for each year in the sample.
- Adjust the prices to be reflective of the standard contract rate for solar QFs.
- Average the five adjusted prices.
- Input the average price into the RVOS model by adjusting the market price used in the standard contract rate.[13]

Q. How does this approach ensure prices are scaled to represent average price under a range of hydro conditions?

A. This approach uses a representative sample of hydro conditions. However, the sample is not random and as such it is difficult to draw statistical conclusions from the result. Also, Idaho Power should not average the results of the sample until after running the prices through the RVOS model. This would allow for non-linear relationships between market prices and energy values. Staff's modified approach would be:

[13] UM 1911 Idaho Power/100, Haener/6.

- Select a random sample with replacement from 82 historic years.
- Perform one Aurora run for each year in the sample.
- Input each Aurora price result into the RVOS model.
- Perform statistical analysis of the RVOS model results.

Q. Please summarize PacifiCorp's approach to modeling hydro variability.

A. PacifiCorp used the following process:

- Construct a forward price curve using expected hydro conditions, hydro generation 25 percent higher than average, and hydro generation 15 percent lower than average.
- Calculate weights for wet and dry years based on relationship between average variance of abnormal years and the variance of the representative year.
- Compare weighted average of three forward price curves against the expected forward price curve.[14]

Q. How does this approach ensure prices are scaled to represent average price under a range of hydro conditions?

A. Because the process includes an average hydro forecast the result is likely to be representative. However, numerous distributional assumptions are required for the application of low and high water years to have meaningful contribution to prices. Staff is also concerned that PacifiCorp uses historic generation, rather than current generation under historic flows. Plant and system differences between the historic and current year make historic

[14] UM 1910 PAC/100, MacNeil/8-12.

generation less relevant to prices going forward. Staff's modified approach would be:

- Select a random sample of hydro years.
- Create a forward price curve for each year in the sample.
- Perform statistical analysis on set of forward price curves.

Q. Please summarize PGE's approach to hydro variability.

A. PGE uses the following process:

- Use average generation calculated in a hydro study that spans 79 years of streamflow conditions.[15]

Q. How does this approach ensure prices are scaled to represent average price under a range of hydro conditions?

A. This approach ensures that the price is representative of the average hydro condition, but it does not inform whether the price is representative of a range of hydro conditions.

Q. Does Staff recommend any modification to PGE's approach?

This approach is not sufficiently developed for Staff to recommend a meaningful modification.

Q. Have the utilities complied with the Commission's directions regarding modeling hydro variability?

A. Staff believes that Idaho Power and PacifiCorp come close, but recommends that these utilities adopt Staff's proposed modifications to their modeling. Staff does not think PGE has properly modeled hydro variability.

[15] UM 1912 PGE/200, Jordan/7-8.

RECOMMENDATIONS RE:

ENERGY ELEMENT

Q. Does Staff recommend refinements to the Phase I Methodology with respect to the determination of the avoided energy element?

A. As discussed above, Staff recommends that the Commission clarify that utilities must use the same forward price curves they use to determine their standard avoided cost prices, but should not default to the actual standard avoided cost price unless warranted by the timing of the RVOS filing and its proximity to utility's avoided cost filing. Staff acknowledges that under the Phase I Methodology, a few of the inputs into RVOS are taken directly from the IRP and mirror the inputs into avoided cost prices. Forward market prices differ from these other inputs in that it is easier to vet new forward market curves than it is to vet new capital costs or contribution to peak of a proxy solar resource.

With respect to the other recommendations Staff mentions above, these recommendations concern the utilities' implementation of the Phase I Methodology rather than the Phase I Methodology itself. These recommendations will be discussed in Staff Exhibit 200 filed in each docket.

ELEMENT 2, GENERATION CAPACITY

Q. Please summarize the Commission's (1) definition of generation capacity, (2) directions to the utilities to do for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: The marginal avoided cost of building and maintaining the lowest net cost generation capacity resource.

Inputs from the Utilities: Utilities shall determine the capacity value consistent with the Commission's standard nonrenewable QF avoided cost guidelines. 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 cost of a utility's avoided proxy resource.

Next Steps: The utilities shall produce this value in Phase II. Utilities shall run sensitivities analysis to determine what level of solar PV penetration has a material effect load resource balance. At a later date of Staff's choosing, Staff is to convene a workshop to explore options for valuing capacity additions incrementally.

Q. What capacity values did the utilities submit?

A. The utility capacity values for RVOS are presented in the table below.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$12.20	$8.65	$7.30	$15.30

Q. How did PacifiCorp determine the value of generation capacity?

A. PacifiCorp valued generation capacity based on the fixed cost of a combined cycle combustion turbine from its 2015 IRP, $149 per kW-year starting in 2028, the year of the next nonrenewable avoided resource in that IRP, multiplied by the solar contribution to the utility's peak load (CTP). PacifiCorp used a factor of 26.1 percent to derive the capacity payment of $23 per MWh starting in 2028, leading to a 25 year levelized value of $12 per MWh.[16]

Q. Does Staff have concerns with PacifiCorp's methodology?

A. Yes. PacifiCorp's 2015 IRP shows that a fixed-tilt utility scale resource in Lakeview, Oregon provides a CTP of 32.2 percent.[17] Staff notes that the 32.2 percent CTP for fixed tilt solar PV is replaced by a 53.9 percent CTP in the 2017 IRP.

Q. Why does PacifiCorp use the lower percent for the RVOS capacity contribution?

A. In its testimony, PacifiCorp appears to propose accounting for the capacity value of each proposed resource individually and on an hourly basis rather than using an estimate based on a proxy's ELCC.[18]

Q. Does this method comport with the method for valuing capacity in Order No. 17-357?

A. PacifiCorp's approach does not follow the QF method as directed by the Commission because it applies an hourly loss of load probability in the E3

[16] UM 1910 PAC/100, MacNeil/19-21.
[17] UM 1910 PAC/100, MacNeil/20.
[18] UM 1910 PAC/100, MacNeil/20-21.

model rather than using the single CTP ratio as provided in the IRP. The CTP from the IRP is used for valuating capacity for QF pricing, and should be used similarly for RVOS at this time.

Staff believes the hourly LOLP concept for capacity may merit exploration for future iterations of the RVOS methodology, but should not be used in the initial RVOS capacity valuation.

Q. Please summarize Staff's recommendation for PacifiCorp for the avoided capacity generation value?

A. Staff recommends that the Commission direct PacifiCorp to use the capacity contribution for fixed tilt solar PV from its recently acknowledged 2017 IRP, which is 53.9 percent. Staff also recommends that any change to PacifiCorp's resource sufficiency arising from the 2017 IRP acknowledgment be incorporated appropriately.

Q. How did PGE determine the value of avoided generation capacity?

A. PGE used the levelized fixed cost of a single cycle combustion turbine from its 2016 IRP, and multiplied this value by the CTP at an assumed solar penetration level from its 2016 IRP.[19]

Staff notes that for QF pricing, PGE's CTP results are applied differently than they are for Idaho Power and PacifiCorp.

Q. Please explain this difference.

A. PGE, in its QF Schedule 201, applies a CTP value that varies with the amount of solar generation on its system, and that amount of solar

[19] UM 1912 PGE/200, Jordan/3-4; Portland General Electric 2016 Integrated Resource Plan, p. 127, Figure 5-11.

contracted to come on to its system. For current QF pricing and the company's RVOS filing, the CTP is based on a solar penetration level of 200 to 300 MW, 15.33 percent.

Q. How did Idaho Power incorporate the value of avoided generation capacity?

A. For the deficiency period starting in 2024, Idaho Power multiplied its current avoided capacity costs used for standard QF rates by the contribution to peak of a solar resource.[20]

Q. Are Idaho Power's and PGE's implementation of the Phase I Methodology for avoided generation capacity consistent with Order No. 17-357?

A. Yes.

Q. The Commission directed each of the utilities to run sensitivities analysis to determine what level of solar PV penetration has a material effect on the load resource balance. Did the utilities do this?

A. PacifiCorp testified that its sensitivities analysis shows that the incremental solar does not delay their resource deficiency dates. Idaho Power testified that the load forecast it used in the 2015 IRP did not include an adjustment for incremental distributed solar PV and that therefor, distributed solar PV had no impact on capacity deficiency timing for the 2015 IRP.[21]

PGE testified that it did not perform the sensitivities analysis because it makes no explicit assumptions about incremental distributed solar PV as

[20] UM 1911 Idaho Power/100, Haener/7.
[21] UM1910 PAC/100, MacNeil/22.

part of the load forecasting process. PGE testified, "[t]he impact of existing distributed solar is included in PGE's historical energy deliveries data and as such is embedded within PGE's regression based load forecast."[22]

Idaho Power testified that its load forecast in the 2015 IRP did not include an adjustment for incremental distributed solar and that therefore distributed solar PV had no impact on capacity deficiency timing for the 2015 IRP.[23]

Q. Is Staff satisfied that the utilities met this requirement?

A. Staff believes that the element has been sufficiently addressed for the purpose of implementing the Phase I Methodology in light of the current relatively low level of distributed solar on the utilities' systems and the constraints of current load forecasting processes.

RECOMMENDATIONS RE:

GENERATION CAPACITY ELEMENT

Q. Does Staff have general concerns regarding how the value for avoided generation capacity is determined in the Phase I RVOS Methodology?

A. Yes, these concerns are similar to those already identified by the Commission. Staff believes there are significant challenges with beginning capacity valuation in the year of the utility's next avoidable resource in the IRP and that a change to this methodology should be addressed as early in the RVOS implementation phase as possible. Order No. 17-357 directed that "[a]t a later date of Staff's choosing, convene a workshop to explore

[22] UM 1912 PGE/200, Jordan/6.
[23] UM 1911 Idaho Power/100, Haener/8.

options for valuing capacity additions incrementally." Staff will initiate this workshop soon.

Q. Does Staff think the Commission should require utilities to use a different method for determining capacity value at this time?

A. No. Staff believes it is appropriate to use the Commission's long-standing method of valuing avoided capacity until there has been opportunity for stakeholder and Commission exploration of issues associated with determining avoided capacity. Aside from PacifiCorp's use of the LOLP rather than the CTP from its IRP and the need for PacifiCorp to update inputs to reflect values from its 2017 IRP, Staff believes the utilities' implementation of Order No. 17-357 with respect to this element is reasonable.

Q. Does Staff have any recommendations for refinements to the Phase I Methodology for the generation capacity element?

A. Staff recommends that the Commission clarify that unless otherwise authorized, the utilities should use the CTP of an Oregon solar resource, taken from their most recently acknowledged IRP, when determining the avoided capacity value.

Staff does have some recommendations (mentioned above) regarding the utilities' implementation of the Phase I Methodology that it will discuss in its Exhibits 200.

ELEMENT 6, INTEGRATION COSTS

Q. Please summarize the Commission's (1) definition of the integration costs, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: The costs of a utility holding additional reserves in order to accommodate unforeseen fluctuations in system net loads due to addition of renewable energy resources

Input from the Utilities: Utilities will make estimates of integration costs based on acknowledged integration studies.

Next Steps: The utilities shall propose this value in Phase II.

Q. What integration values did the utilities submit?

A. The utility integration values for RVOS are presented in the table below.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
($0.82)	($0.63)	($0.83)	($0.56)

Q. Please provide an overview of integration costs in the context of RVOS.

A. Solar resources generate varying amounts within short time periods. A utility must follow this variable generation on its system by holding aside operating reserves for within-hour and hour-to-hour variations. Many factors impact the costs and level of reserves required. A typical integration study incorporates a broad set of assumptions about many factors impacting the integration cost, including resource costs and available flexibility, geographic diversity of the variable resource, granularity and timeframe of resource performance data and many more.

Q. Why does the current level of solar penetration matter?

A. Similar to the relationship between the value of the contribution to peak value of solar and the level of solar penetration on a utility system, there can be a relationship between the cost per unit of integrating solar and the level of solar penetration.

Q. What values did the utilities use for integration in their RVOS filings and what are the bases for these values?

A. PacifiCorp used integration costs from its Flexible Reserve Study from its 2017 IRP,[24] which was acknowledged December 11, 2017, at the Commission's public meeting.

PGE's value for integration costs is based on variable integration cost as calculated in its 2016 IRP.[25] However, Staff does not yet have an understanding of whether or how PGE differentiated between different types of variable resources, which include non-solar generation.

Idaho Power based its integration costs on the solar integration study approved by the Commission in Docket No. UM 1793.[26] The cost varies with the Company's solar penetration level, assumed to be 301 to 400 MW for 2018.

[24] UM 1910 PAC/100, MacNeil/31-32.
[25] UM 1912 PGE/100, Goodspeed/11.
[26] Idaho Power/100, Haener/17; Order No. 17-075, March 2, 2017.

Q. Do the methods used by the utilities to obtain integration cost values comply with Order No. 17-357?

A. For the most part, yes. Staff addresses in more detail Staff's recommendation for PGE's approach in Exhibit 200.

RECOMMENDATIONS RE:

INTEGRATION COSTS ELEMENT

Q. Does Staff recommend refinements to the Phase I Methodology for the integration costs element?

A. Not at this time.

<u>LOCATION-SPECIFIC SYSTEM ELEMENTS</u>

Q. What are the RVOS elements that comprise the location-specific system values associated with solar power?

A. Staff has grouped three of the RVOS elements into the category of location-specific values. They are:

- Element 3, Transmission and Distribution Capacity
- Element 4, Line Losses
- Element 11, Grid Services

Staff created this category of RVOS elements for two reasons. First, it helps to conceptualize the link between a solar system's location and certain values within RVOS. Second, it helps to frame those elements that would be most impacted by any future improvements in the granularity in locational data.

ELEMENT 3, TRANSMISSION AND DISTRIBUTION CAPACITY

Q. Please summarize the Commission's (1) definition of transmission and distribution capacity, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: Avoided or deferred costs of expanding, replacing, or upgrading transmission and distribution (T&D) infrastructure.

Inputs from the Utilities: Utilities shall develop a system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration in Oregon service areas.

Next Steps: The utilities shall propose this value in Phase II. Utilities are to comment on how their distribution planning could advance the granularity of this element for the next iteration of RVOS.

Q. What transmission and distribution (T&D) capacity values did the utilities submit?

A. The utility T&D values for RVOS are presented in the table below.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$0.08	$0.05	$8.08	$0.87

Q. Please explain how each of the three utilities determined the T&D capacity value.

A. PGE based its T&D capacity value on the marginal cost of service study used for its 2017 rate case. The value for an avoided distribution asset was estimated to be the cost of subtransmission costs plus substation costs, in dollars per kW-year. The transmission value is based on the 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. This combined value is $21.52 per kW-year for 2018. Escalation rates for both transmission and distribution are estimated to be 2%, which is consistent with the 2016 IRP.[27]

Idaho Power used the energy efficiency (EE) value from its 2017 IRP as the value for avoided T&D Capacity in its RVOS calculation. To obtain the value, Idaho Power calculated the total savings from all the deferrable T&D projects within its 2016 budget. After it determined which projects are deferrable as a result of EE, it combined the benefits and divided by the total annual EE reduction forecast over the service area. Based on the analysis, a value of $3.76/kW-year was determined as the T&D deferral value for EE. This $3.76kW-year value was divided evenly between the transmission deferral value and distribution value – resulting in $1.88/kW per-year for each input.[28]

PacifiCorp used a similar methodology to that used by Idaho Power. PacifiCorp updated the T&D deferral calculation that it used for the analysis of demand-side management resources in its 2017 IRP. PacifiCorp obtained the average deferral value of deferred T&D investment based on three specific

[27] UM 1912 PGE/400, Murtaugh/6-8.
[28] UM 1911 Idaho Power/100, Haener/9-10.

forecasted capacity additions (T&D projects) that PacifiCorp believes are subject to deferral by solar penetration in its Oregon territory.[29]

Q. Does Staff have concerns with any of these methodologies?

A. Yes. Staff does not think PacifiCorp and Idaho Power produced an adequate "system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration in Oregon service" as directed by Order No. 17-357.

The methodologies used by PacifiCorp and Idaho Power require more investigation before they should be used to determine a RVOS. As noted by Arne Olson of E3 in Docket No. UM 1716, T&D costs can be calculated at the system average level or for more specific locations such as utility distribution planning areas or even distribution feeders. Oregon IOU's do not currently produce values that specifically measure avoidable T&D costs. Mr. Olson recommended that in the absence of more specific values, marginal cost of service studies (MCOS) provide a reasonable basis for calculating avoided T&D capacity value.[30]

Staff appreciates PacifCorp's and Idaho Power's effort to obtain more locational granularity in the value for avoided T&D capacity, but does not think the circumstances yet support proposed methods for determining avoided T&D capacity.

[29] UM 1910 PAC/200, Putnam/4.
[30] UM 1716 Staff/401, Olson/22 (Staff Response to TASC DR No. 19).

Further, Staff disagrees with PacifiCorp and Idaho Power that it is appropriate to use energy efficiency T&D deferral values for the estimation of the RVOS. By definition, this is not a resource value of solar but a resource value of energy efficiency. While Staff appreciates possible synergies Staff has not been presented with enough data at this time to confirm that values are the same.

RECOMMENDATIONS RE:

T&D CAPACITY ELEMENT

Q. Does Staff have a recommendation for refining the Phase I Methodology with respect to the T&D capacity element?

A. Yes. Staff recommends that the Commission require all three utilities to use the MCOS method used by PGE until a more reliable and transparent location-specific methodology is approved by the Commission.

ELEMENT 4, LINE LOSSES

Q. Please summarize the Commission's (1) definition of avoided line losses, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: Avoided marginal electricity losses.

Inputs from the Utilities: Utilities shall develop hourly averages of avoided marginal line losses attributable to increased penetration of solar PV systems in Oregon service areas. The incremental line loss estimates shall reflect the hours solar PV systems are generating electricity

Next Steps: The utilities shall propose this value in Phase II.

Q. What values did the utilities submit for line losses?

A. The utility values for line losses are presented in the table below.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$1.96	1.54	$1.48	$2.54

Q. How did each of the three utilities address the line losses element?

A. PacifiCorp began with the transmission, primary, and secondary losses currently reflected in retail rates, which reflect the company's most recent line loss study. For the RVOS line loss element, PacifiCorp conducted power flow studies that identified the primary and secondary line losses at 100 percent, 90 percent, and 75 percent of both winter and summer peak loads to supplement the previous study. These losses were then fitted to a 12-month and 24-hour profile to create the marginal losses for resources connected at either the primary or secondary voltage level.

PacifiCorp testified that obtaining location specific line losses would have little impact and that it is not worth the significant amount of time it would take. The value for line losses would depend on the degree to which the generation stays behind the meter. Generation that is sent out to distribution or transmission system will get less value.

PGE calculated seasonal and high- and light-load line loss data. PGE captured losses for each distribution power transformer in substations, as well as each of their corresponding distribution feeders. For the distribution feeders, losses were calculated for all primary circuits. Utilization transformers, secondary, or service wires were not included in this study. PGE does not have hourly data and would need to undertake a study of the T&D system and assigning net system load estimates by hour throughout the year. PGE testifies that a more expedient option would be to calculate a handful of representative samples based on net system load estimates. PGE testifies that this method is similar to the studies that PGE has produced for the initial proposal of the line loss element, but with additional seasonal/daytime variation.

Idaho Power uses loss data from 2012 to develop average losses for on-peak, mid-peak, and off-peak hours in summer and winter. All the values were between 8.5 and 8.7%.[31]

Q. What are Staff's conclusions regarding the utilities' determinations of the RVOS for line losses?

A. Staff believes that the utilities' implementation of the line loss element is reasonable and complies with Order No. 17-357.

RECOMMENDATIONS RE:

LINE LOSSES ELEMENT

Q. Does Staff have any recommendations regarding the Phase I Methodology with respect to the line losses element?

A. Not at this time.

[31] UM 1911 Idaho Power/100, Haener/4.

ELEMENT 11, GRID SERVICES

Q. Please summarize the Commission's (1) definition of grid services, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: The potential benefits of solar PV in advanced, uncommon applications and from utilities' increasing ability to capture the benefits of mass-market smart inverters.

Inputs from the Utilities: The utilities shall use a value of zero for this element

Next Steps: To be evaluated based on future proposals.

Q. Does Staff have any recommendations regarding the grid services element?

A. Not at this time.

NON-SYSTEM ELEMENTS

Q. What are the RVOS elements that comprise the non-system values associated with solar power?

A. Staff has grouped five of the RVOS elements into the category of Non-system. They are:

Element 5, Administration

Element 7, Market Price Response

Element 8, Hedge Value

Element 9, Environmental compliance

Element 10, RPS compliance

Staff created this category of RVOS elements to differentiate those RVOS elements for which the value is derived from regulations and laws and from market characteristics, rather than from the impact on the utility's physical system.

ELEMENT 5, ADMINISTRATION

Q. Please summarize the Commission's (1) definition of administration, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: Increased utility costs of administering solar PV programs.

Inputs from the Utilities: Utilities shall develop estimates of the direct, incremental costs of administering solar PV programs including staff, software, incremental distribution investments, and other utility costs.

Next Steps: The utilities shall propose this value in Phase II. Utilities shall provide justification for their method and value.

Q. What values did the utilities submit for administration?

A. The utility administration values for RVOS are presented in the table below.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized[32]	PGE Real Levelized	Idaho Power Real Levelized
($2.59)	($1.80)	($5.58)	($47.77)

Q. How did each of the three utilities address the administration element?

[32] See footnote 2.

A. PacifiCorp includes three types of costs in the computation of administration costs: (1) incremental unrecovered administration and engineering costs associated with processing customer requests to participate as an RVOS resource, (2) incremental ongoing administration costs for customer service and billing, and (3) incremental distribution investments required to facilitate the interconnection of DG but that are unrecovered from the customer.[33] PacifiCorp determined incremental unrecovered administration amounts by multiplying the overall expense of department by total capacity of program then subtracted costs received from participants, then divided by total incremental capacity. PacifiCorp determined administration costs from billing and customer service departments for initial application and connection and costs from engineering. PacifiCorp determined "ongoing" administration costs by starting with total costs for net metering for new and existing customers and dividing by average interconnected capacity amount. Finally, PacifiCorp determined incremental investment by establishing specific account that captures system upgrades and other capital expenditures directly attributable to net metering.[34]

PGE included costs of its Customer Interconnection and Specialized Billing groups for their work related to net metering. PGE specifically excluded administrative costs for Community Solar administration.[35]

---

[33] UM 1910 PAC/100, MacNeil/27-28.
[34] UM1910 PAC/100, MacNeil/28-31.
[35] UM 1912 PGE/100,Goodspeed/12.

Idaho Power's value for administration is based on 2016 actual expenses for the Oregon Solar Photovoltaic Pilot Program, including $14,065 in labor costs, $23,899 in communication service fees, and $638 in other operational expenses, totaling $38,601 in costs, divided by the 808 MWh of generation from the program for 2016 and then escalated each year at the 2.2 percent rate from the 2015.[36] Idaho Power states as these are the actual costs of administering these projects, it is appropriate to reflect these costs in the administration component of the RVOS. Idaho Power notes that $23,899 of administration costs associated with communication service fees would not be included once pilot phase is over, changing the RVOS value for administration costs to ($31.18).[37]

Q. Does Staff have concerns with how any of the utilities determined the value for administration?

A. Yes. Staff concludes that Idaho Power's method is not appropriate. Using the VIR as the denominator does not provide an applicable estimate of administrative costs over the 20+ year of an RVOS agreement.

Over time, the update calculation for core RVOS values should incur costs similar to those of the annual avoided cost updates for QFs. Costs of developing location-specific RVOS values will likely be significant, but rather than assuming those costs to be RVOS-related, they should be allocated as part of the core tasks of distribution system planning.

---

[36] UM 1911 Idaho Power/100, Haener/15-16.
[37] UM 1911 Idaho Power/100, Haener/15-16.

Staff notes that the Administration element for RVOS accounts for implementation of a program,[38] and therefore these initial values will vary to some extend depending on the specific program requirements. Once a utility program is implemented based on RVOS methodology, those costs appropriately become part of the cost/benefit analysis specific to that program and not a generic "RVOS cost" per se.

RECOMMENDATIONS RE:

ADMINISTRATION ELEMENT

Q. Does Staff have any recommendations regarding the Phase I Methodology with respect to the Administration element?

A. Not at this time. Staff's concerns with Idaho Power's implementation of the Methodology will be addressed in Staff 200 in Docket No. UM1911.

ELEMENT 7, MARKET PRICE RESPONSE

Q. Please summarize the Commission's (1) definition of market price response, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: The change in utility costs due to lower wholesale energy market prices caused by increased solar PV production.

Inputs from the Utilities: Staff is to coordinate or facilitate use of E3' s model to create a proxy value for market price response that utilities will use in their initial RVOS filings

[38] Order No. 17-357, p. 22.

Next Steps: Utilities shall include the proxy value in their Phase II filings.

Q. What market price response (MPR) values did the utilities submit?

A. The utility MPR values for RVOS are presented in the table below.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$0.15	Not Provided	$1.81	$0.00

Q. Please provide a little more explanation of the market price response element?

A. The MPR measures the value created from solar generation reducing wholesale prices. With no fuel costs, solar facilities nearly universally produce cheaper than wholesale market prices. With sufficient solar generation underbidding the market, all things equal buyers will be less willing to accept previous prices, and thus the wholesale settling prices will decrease.

The impact on a utility depends on its position in wholesale markets. If it buys more then it sells (the utility is 'net-long'), then a reduction in wholesale prices leads to positive benefit toward the utility. If it sells more than it buys ('net-short'), then this response will be negative.

Q. How can the MPR be calculated?

A. The exact formula provided by E3 multiplies the change in wholesale prices by the size of the net short/long position, and divides this number by the solar generation that caused that change in wholesale prices.[39] The two latter inputs (the size and direction of the utility's market position and size of solar resources) are easily accessible, however the magnitude of potential price change is difficult to estimate.

E3 suggested deriving the magnitude of potential price change in one of two ways: (1) use a range for the market price elasticity[40] from -.001 percent to -.002 percent or (2) conduct sequential runs of a production simulation model with and without the solar resource in order to measure the price response. The first option is simple, but does not provide the granularity of price responses during different periods, which is crucial when considering production-limited solar PV resources.

Whichever market price elasticity approach employed, either using E3's value or simulating an actual market response, the final calculation becomes relatively straightforward for the utility.

Q. How did Idaho Power determine the MPR value?

A. Idaho Power used AURORA, a wholesale market-forecasting tool, to determine its MPR value is negative. However, Idaho Power submitted a MPR value of zero as they do not believe their cumulative solar generation of .41MW is significant enough to influence market prices.[41]

---

[39] For example, for a net-short utility that purchases 100 MWh on wholesale markets, a 50 MWh solar addition causing a .1% reduction in prices (from say $25/MWh to $24.975/MWh) would be generating a value of $.05/MWh to that utility.
[40] The change in price from a change in generation. A market price elasticity of -.1 percent signifies that an increase of 100MWh in solar generation would lead to a $.1 reduction in market prices.
[41] UM 1911 Idaho Power/100, Haener/36-37.

Q. Is this reasonable?

A. No. So long as the marginal cost of solar generation is below the market price of electricity, the marginal impact of every kilowatt addition of solar will depress market prices. It is certainly true that if a utility's cumulative solar capacity is small, this effect will be small (and thus IPC's value of $0.0 could be appropriate). However renewable generation is widely predicted to continue to grow, impacting market prices sufficiently to be a tangible source of value.

Q. How did PGE calculate the MPR value?

A. PGE used two scenarios in AURORA to determine the MPR value.[42]

Q. Did PGE calculate the MPR consistently with the Phase I Methodology?

A. Yes.

Q. Does PGE have concerns about the calculation of MPR?

A. Yes, PGE has three main concerns: 1) the potential double counting the benefits of solar, 2) uncertainty of market penetration, and 3) market displacement.[43]

Q. Does Staff agree with any of these concerns?

A. Yes, Staff agrees that there is a potential for double-counting the value of solar. If there is a positive value associated with the MPR derived from reduced wholesale prices, then there should also be a reduction in energy (avoided cost) value. A reduction in the marginal cost of wholesale energy

[42] UM 1912 PGE/300, Sims/8-9.
[43] UM 1912 PGE/300, Sims/10-11.

prices reduces the costs avoided by solar generation, and that reduction should be reflected in the energy value.

Q. Does Staff disagree with any of these concerns?

A. Yes, Staff is skeptical about PGE's second and third points. For the second, while it is true that an overestimation of market penetration could lead to an overpayment to solar generators, the converse could also be true. The EIA consistently underestimates the amount of solar development; regional predictions could do the same.

To PGE's third point, solar generation that displaces planned or existing renewables (or other inframarginal producers)[44] will produce no *additional* MPR. However that response will still occur, and still provides value to the utility. Accordingly, Staff believes MPR should be part of RVOS.

Q. What is PacifiCorp's MPR value?

A. PacifiCorp estimates MPR to be worth either $0.15/MWh using the standard methodology as ordered by the Commission. This value is expressed as nominal levelized over 25 years.

Q. How did PacifiCorp calculate its MPR value?

A. PacifiCorp used production simulation model runs that evaluated different hydro scenarios to evaluate a market price response. With little variable cost associated with hydro production, the Company argues that it is plausible to

[44] Generating facilities willing and able to produce electricity for less that the current market price.

expect a similar negative wholesale price effect as would be expected with solar generation.[45]

Q. Does Staff believe this produces reasonable estimates?

A. Yes. As long as the generation costs of the hydro facilities are below both current and modeled wholesale market prices, then the constraints on price reduction will still bind. The source of the modeled increase in production does not matter, what is important is that the marginal producers are accurately reflected and that the supply change does not exceed the actual merit order. If these conditions are met, then the elasticity estimates should remain as accurate as possible.

However, Staff does have some questions about PacifiCorp's MPR value. Staff's uncertainty results from the Company's decision to calculate MPR outside of the E3 model as an outboard adjustment without applying the E3 model's levalization methodology. This issue is discussed later in this testimony under the topic of Outboard Adjustments.

Q Does PacifiCorp have concerns regarding the MPR element?

A. Yes. Similar to PGE, PacifiCorp states if there is a positive value associated with the MPR derived from reduced wholesale prices, then there should also be a reduction in energy (avoided cost) value. A reduction in the marginal cost of wholesale energy prices reduces the costs avoided by solar generation, and that reduction should be reflected in the energy value. Further, PacifiCorp argues that the MPR should incorporate take into account

[45] UM 1910 PAC/100, Haener/33-34.

recent solar additions in both PacifiCorp's portfolio as well as other WECC participants.[46]

Q. Are these concerns are reasonable?

A. Yes and no. Staff agrees with PacifiCorp (and PGE) that if there is no change in avoided energy costs reflected in RVOS, then there is a potential to double count the benefits associated with solar. Staff is less sure of PacifiCorp's second point. Unless solar generation is the marginal producer, any increase in solar production will continue to depress market prices, even with recent additions to the market. While there are periods of a day (sunny, windy hours with comfortable temperatures) where market price elasticity will certainly be smaller, it remains reasonable to include this value in the RVOS. Staff certainly expects future analyses to demonstrate the declining marginal benefit associated with solar generation not paired with storage.

RECOMMENDATIONS RE: MARKET PRICE RESPONSE ELEMENT

Q. Does Staff have any recommendations to refine the Phase I RVOS Methodology with respect to the Market Price Response element?

A. Staff does have recommendations regarding the utilities' implementation of the Methodology, which Staff will address in Staff Exhibit 200.

[46] UM 1910 PAC/100, Haener/34.

ELEMENT 8, HEDGE VALUE

Q. Please summarize the Commission's (1) definition of hedge value, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: Avoided cost of utility hedging activities; i.e., transactions intended solely to provide a more stable retail rate over time.

Inputs from the Utilities: Utilities are to assign a proxy value of 5 percent of energy.

Next Steps: Utilities shall include the proxy value in their Phase II filings.

Q. What hedge values did the utilities submit?

A. The utility hedge values for RVOS are presented in the table below.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$1.54	$1.21	$1.25	($1.49)

Q. What is the hedge value?

A. The hedge value represents the benefit provided by solar to utilities from the certainty of generation costs. Utilities employ hedging strategies to insulate themselves from risk by purchasing contracts for future deliveries at fixed prices. To do this, they are charged a premium over the expected price. If fuel prices rise this strategy is seen in hindsight to have saved the utility money. However, if prices fall the utility ends up paying a higher price than they otherwise would have had they just bought from spot markets.

Given fuel prices volatility, utilities generally are willing to pay to reduce their exposure to uncertainty, going so far as to pay a premium to take this bet. However utilities get this benefit from solar for free. By generating without fuel, solar provides price certainty to the utilities. Instead of paying these hedge contract premiums, they know for 20 years exactly what the price of generation from solar resources will cost. As this reduction in exposure is a cost for which utilities are willing to pay, solar generation provides a quantifiable benefit to this avoided cost.

Q. How has Staff recommended the value for this element be calculated?

A. Leaning on the analysis by E3, Staff has recommended that utilities simply use five percent of the total energy value. This number comes from a 2011 analysis by DeBenedictus et al. that measured risk premiums in the Pacific Northwest. [47]

Q. Why can't we just quantify the actual utility hedging strategies?

A. Each utility has an individual hedging strategy, dictated by its generation mix, internal risk tolerance, and commission oversight. A single methodology for determining the RVOS hedging value will not be suitable for all the utilities.

Q. So five percent is only meant as a proxy?

A. Yes. There clearly is a value from solar associated with avoided hedging costs. According to the best and most recent analysis of the region, that

[47] DeBenedictis, A., Miller, D., Moore, J., Olson, A., & Woo, C. K. (2011). How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest. *The Electricity Journal*, *24*(3), 72-76.

value is close to five percent of total energy costs. As the hedging value represents only a small part of the total RVOS value, the marginal benefit associated with developing a more refined methodology likely is far outweighed by the associated marginal costs.

Q. How did PacifiCorp calculate its hedging value?

A. PacifiCorp used the Commission- and E3-recommended five percent value of energy.

Q. Does PacifiCorp have any concerns with this calculation?

A. Yes. As explained in the earlier UM 1716 docket, PacifiCorp believes the hedging value is close to zero. PacifiCorp's reasoning is that the marginal costs in the energy imbalance market (EIM) already decrease significantly during times of high production and that the additional benefit from solar constrained to generation during those times is likely low.

Q. Does Staff agree with this point?

A. Today, yes: Given current market conditions this makes sense. However given tremendous uncertainty regarding the cost of natural gas production, i.e., uncertainty related state and federal climate policy, it is plausible that natural gas prices could sharply increase in the next 20 years. In this circumstance, even saturated solar production would be beneficial. Staff does not believe that current market conditions negate the value of stable generation prices.

Q. What is PGE's hedging value?

A. PGE estimates the hedging value element to be worth $1.25/MWh in 2017 levelized dollars.

Q. How did PGE calculate this value?

A. PGE used the Commission- and E3-recommended five percent value of energy.[48]

Q. Does PGE have any concerns with this calculation?

A. Yes. PGE does not believe the process noted above accurately reflects its hedging strategy. It highlights that in the analysis that generated the five percent proxy value, the time period and gas hub used was not representative. Further, PGE notes its use of layering its hedges throughout a year.

Q. Does Staff agree with these concerns?

A. Staff agrees that incorporating these changes would likely produce a more accurate hedging value. However it is unclear to Staff how much better each potential change would make in the output: for example, AECO and Henry Hub gas prices are highly co-integrated, such that changing this data source would likely produce very similar results.

Q. Does Staff believe that these concerns justify a new calculation?

A. Not at this point. The marginal benefits of new analysis (namely a more accurate hedging value representation in RVOS) would not likely equal the costs of updating the analysis performed in DeBenedictus et al. (2011)

[48] UM 1912 PGE/300, Sims/1-2.

study.[49] PGE requests that a calculation based on an external whitepaper not be precedential, however Staff views the 5 percent proxy as the best available information. It is relevant that PGE estimates that AHV represents ~2.5 percent of the RVOS value: fine-tuning this in the future would likely provide some benefit, but it will not greatly affect the final RVOS value.

Q. What is Idaho Power's hedge value?

A. Idaho Power produced a hedge value of $1.49 in real levelized dollars.[50]

Q. How did Idaho Power calculate this value?

A. Idaho Power used the Commission- and E3-recommended five percent value of energy.[51]

Q. Does Idaho Power have any concerns with this calculation?

A. Yes. As described in their early Docket No. UM 1716 testimony,[52] Idaho Power has a specific hedging strategy approved by the Idaho Public Utilities Commission.[53] Their Risk Management Policy Manual described the policies and procedures that minimizes risk, but does not change based on the amount of solar generation the company has built.

Q. How does Idaho Power propose to address this issue?

A. Idaho Power proposes that the hedge value be set to a value of zero.

---

[49] DeBenedictis, A., Miller, D., Moore, J., Olson, A., & Woo, C. K. (2011). How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest. *The Electricity Journal*, *24*(3), 72-76.
[50] UM 1911 Idaho Power/100, Haener/20.
[51] UM 1911 Idaho Power/100, Haener/20.
[52] UM 1716 Idaho Power/100, Younglblood.
[53] In the Matter of Idaho Power Company's Interim and Prospective Hedging, Resource Planning, Transaction Pricing, and IDACORP Energy Solutions (IES) Agreement, Case No. IDAHO POWER-E-O1-16 (Phase ll), Order No. 29102 (Aug. 28, 2002).

Q. Is this appropriate?

A. No. As explained below, differences in hedging strategies do not signify that the actual financial value provided by increasing solar does not exist. There clearly exists a benefit from having a fixed price of electricity generation twenty years into the future.

RECOMMENDATIONS RE:

HEDGE VALUE ELEMENT

Q. Does Staff have a recommendation for modifying the Phase I Methodology for the hedge value element?

A. Not at this time.

<u>ELEMENT 9, ENVIRONMENTAL COMPLIANCE</u>

Q. Please summarize the Commission's (1) definition of environmental compliance, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. <u>Definition</u>: Avoided cost of complying with existing and anticipated environmental standards

<u>Inputs from the Utilities</u>: For informational purposes, utilities shall estimate the avoided cost based on a reduction in carbon emissions from the marginal generating unit. To value future anticipated standards utilities should use the carbon regulation assumptions from their IRP.

<u>Next Steps</u>: The utilities shall calculate this value for informational purposes and include it in their Phase II filing.

Q. What environmental compliance values did the utilities submit?

A. The utility environmental compliance values for RVOS are presented in the table below.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$0.11	$0.08	$11.41	$0.00

Q. Please elaborate on the Commission' directions regarding determining the value of environmental compliance.

A. Commission Order No. 17-357 directs utilities to "estimate the avoided cost based on a reduction in carbon emissions…[U]tilities should use the carbon regulation assumptions from their IRP." Commission Order No. 15-296 regarding the IRP Guidelines states that the Commission "[W]ill only consider elements that could directly impact the cost of service to utility customers. For example, we would consider the potential financial costs to utilities of future carbon regulation. On the other hand, for example, we will not consider job impacts of solar development."

Q. How did the three utilities calculate the avoided environmental compliance value for RVOS?

A. PGE utilized the mid-national carbon price forecast from Docket No. LC 66 – PGE's 2017 IRP. This forecast was published by Synapse Energy

Economics in its “Spring 2016 National Carbon Dioxide Price Forecast.” This forecast is included as PGE/501.[54]

Idaho Power included a zero value for environmental compliance based on the fact it modeled zero compliance costs in its 2015 IRP.[55]

PacifiCorp differentiated between cost compliance during periods of resource sufficiency and deficiency. PacifiCorp included no compliance cost associated with market purchases during the sufficiency period. For the deficiency period, PacifiCorp based the value on PacifiCorp’s cost to comply with the Clean Power Plan (CPP) year during the 25-year period, PacifiCorp explains that CPP compliance costs average around $6 per ton from 2024 to 2028 ad that starting in 2029, emissions drop below cap threshold so compliance payments cease. PacifiCorp notes that deficiency period starts in 2028, so only includes compliance costs that would be incurred 2028.[56]

Q. Does Staff have concerns with any of these methodologies?

A. Staff has concerns regarding the approaches taken by Idaho Power and PacifiCorp. Staff discusses these concerns in the Staff Exhibits 200 in Docket Nos. UM 1910 and UM 1911.

RECOMMENDATIONS RE:

ENVIRONMENTAL COMPLIANCE ELEMENT

Q. Does Staff have a recommendation for modifying the Phase I Methodology for the environmental compliance element?

---

[54] UM 1912 PGE/500, Carpenter/4; PGE 2016 IRP, Chapter 3.
[55] UM 1911 Idaho Power/100, Haener/21.
[56] UM 1910 PAC/100, MacNeil/35-38.

A. Not at this time.

ELEMENT 10, RPS COMPLIANCE

Q. Please summarize the Commission's (1) definition of RPS Compliance, (2) directions to the utilities for this element, and (3) next steps for further refining the methodology for this element.

A. Definition: To be determined.

Inputs from the utilities: The utilities shall use a placeholder value of zero in their initial Phase II filings.

Next Steps: The Commission noted that the avoided cost of RPS compliance overlaps with several other pending dockets and that the Commission will endeavor to assign a methodology before the end of Phase II.

Q. Did the utilities address the RPS compliance element in their filings?

A. PacifiCorp states that it has no RPS-compliance shortfall until 2035.[57] PGE briefly discusses potential overlap between this element and the environmental compliance element, and also potentially with the market price response element.[58]

Idaho Power explains that it has no RPS in Idaho, and that it "would already be in compliance with the Oregon RPS requirements to be met in 2025 without incurring additional costs."[59]

---

[57] UM 1912 PAC/100, MacNeil/39-40.
[58] UM 1911 PGE/500, Carpenter/6.
[59] UM 1911 Idaho Power/100, Haener/22.

RECOMMENDATIONS RE:

RPS COMPLIANCE ELEMENT

Q. Does Staff have a recommendation on this element going forward?

A. Staff believes a potential approach to this element would be to apply the $ per MWh from utilities' renewable portfolio compliance reports to the reduction in RPS obligation from distributed solar MWh production.

SECTION 3: OTHER RVOS ISSUES

<u>RVOS VALUES</u>

Q. Did Staff find any issue with the reporting of the values for the RVOS elements?

A. Yes. In Order No. 17-357, the Commission gave general instruction for calculating E3 model inputs and using the E3 model to calculate RVOS. The Commission directed companies to "… populate the E3 workbooks …" and to use "… methodologies more specifically described by E3's formulas …" to produce a levelized Resource Value of Solar.[60, 61] Idaho Power and PGE appear to have utilized the E3 RVOS workbook without making changes to the model. However, Staff is concerned that PacifiCorp has made multiple outboard adjustments to the results of the E3 model. First, although the E3 workbook reports RVOS elements in real-levelized dollars, PacifiCorp has calculated and reported RVOS elements in "nominal-levelized" dollars.[62]

[60] Order No. 17-357, Page 2.
[61] Order No. 17-357, Page 1.
[62] UM 1910 PAC/100, MacNeil/3 at 5.

Second, the Market Price Response (MPR) RVOS element reported by PacifiCorp is the result of an outboard adjustment to the E3 model. The workpapers provided by PacifiCorp showing the calculation of the MPR RVOS element indicate that the value reflects only one year and has not been levelized. Staff's concern is that these adjustments reduce transparency and accuracy in RVOS calculations.

RVOS VALUES

Q. Please explain Staff's concern regarding the reporting of RVOS in real levelized versus nominal levelized dollars.

A. PacifiCorp's filed version of the E3 model contains a calculation to determine nominal levelized RVOS that is not present in the E3 model. This change results in a substantially different RVOS that the real levelized RVOS reported by the E3 model and the other utilities. The E3 Model's real levelized RVOS is 23 percent lower than PacifiCorp's nominal levelized RVOS.

Q. What does Staff recommend regarding the reporting of RVOS in real levelized or nominal levelized dollars?

A. Staff acknowledges that real levelized and nominal levelized RVOS are simply different ways of looking at the same question. A real levelized RVOS reflects the present value of solar on a per MWh basis in 2018 dollars. A nominal levelized value reflects the actual dollars per MWh that a Distributed Solar Generator (DSG) would receive each year under a fixed-rate contract.

Q. What does Staff recommend regarding how the RVOS values are reported?

A. Staff suggests that the utilities should report both real levelized and nominal levelized dollars in order to provide more insight and transparency to stakeholders. Staff is also interested in further discussions about real levelized versus nominal levelized values and whether solar contracts should be fixed-price or updated.

RVOS OUTBOARD MODEL ADJUSTMENTS

Q. What is Staff's concern with PacifiCorp's outboard adjustment to the E3 model involving the Market Price Response element?

A. Instead of using the E3 model to calculate MPR, PacifiCorp calculated it by hand as an outboard adjustment. PacifiCorp then subtracted MPR from the energy RVOS element in another outboard adjustment. While PacifiCorp provided testimony describing its calculation of MPR, it did not clearly explain that a method other than the E3 model had been utilized.

Further, PacifiCorp's outboard adjustment contains an assumption that the MPR will have an equal and opposite effect on the energy element. Staff notes that the chances are low that the MPR element will have a one-to-one effect on the energy RVOS element.

Q. What is your recommendation regarding PacifiCorp's MPR outboard adjustment?

A. First, PacifiCorp should report the MPR and energy elements separately instead of using the MPR element as an offset to the energy element. Second, PacifiCorp should calculate an estimated MPR that can be included as an input to the E3 model.

Q. Does Staff have any other recommendations regarding outboard adjustments to the E3 model?

A. Staff understands that parties may find reasons to make adjustments or modifications to the E3 model. However, in the interest of fairness and transparency to all parties, Staff recommends that any proposed changes to the E3 model should be accompanied by a detailed explanation of the changes and of why such changes are justified.

UTILITY SCALE SOLAR PROXY

Q. What is the purpose of having utilities include a parallel version of RVOS using a utility scale solar proxy as the avoided resource?

A. Order No. 17-357 described the purpose of providing a separate RVOS based on avoiding a utility scale solar proxy as providing a reference point to advance understanding of evaluation methods. The order included specific guidance that the avoided cost of the utility scale solar proxy resource would replace all but three of RVOS elements, T&D capacity, administration, and line losses, with a separate workbook. As further described in their June 1, 2016 testimony, E3 explained that at some point in the future, “the cost to the utility of serving load with conventional generating resources (either natural gas-fired resources or market purchases) may exceed the cost to the utility of acquiring a like amount of solar energy at utility scale.”

It is Staff’s understanding that the Commission’s request for inclusion of the Utility Scale solar proxy (Utility Scale) alongside the standard version of

RVOS was to provide informational value about how different the avoided costs of various resources are currently.

Q. How have the utility responses to the utility scale solar proxy helped advance understanding of evaluation methods?

A. At this point, the results provided have not necessarily helped to advance our understanding for two reasons. First, despite the Commission's direction regarding a utility scale RVOS value, each of the utilities approached the Utility Scale version of RVOS in a different way so there is no consistency for comparison of results across utilities. Second, even though some methodology specifics were described in each filing, the explanations for how the Utility Scale values were provided, and the rationales for the methodologies, were not consistent either. These two points lead Staff to question the overall value in these responses.

Q. Should provision of the utility scale proxy method continue in parallel to the RVOS?

A. Yes, Staff does recommend that a Utility Scale version of RVOS be provided but suggests that the Commission consider clarifying the direction and intent to utilities.

Q. What clarifications do you recommend?

A. If the Commission would like to receive Utility Scale RVOS as a reference, Staff suggests adding the following points of clarification:

- The most recently acknowledged IRP or IRP update should be the source for the cost estimate of the avoided Utility Scale proxy resource.

- The earliest year of capacity deficiency in the IRP should be used as the start year for capacity value, regardless of whether that capacity need is driven by a renewable or nonrenewable resource need.
- The Utility Scale solar resource should be defined as 50 MW or larger in capacity interconnected at the transmission level of the system.
- The purpose of the Utility Scale version is to illustrate the avoided costs to the utility in acquiring solar through distributed projects instead of large utility scale solar acquisitions as a theoretical reference point.

RVOS UPDATES

Q. The Commission has stated that it "will decide later, based on application, whether RVOS should be updated annually or every two years."[63] Did the utilities address the question of update frequency?

A. Yes. PGE[64] and PacifiCorp[65] advocate for frequent updates. PacifiCorp recommends that as updates to certain inputs are incorporated in standard pricing for qualifying facilities, those inputs should then be updated in the RVOS calculation.[66]

Q. What is the Staff position on RVOS update frequency?

A. Staff believes that, for certain elements, existing processes for PURPA QF avoided cost updates should be leveraged to achieve efficiency and predictably. Given that, Staff supports an annual update process for energy

63 Order No. 17-357 at 17.
64 UM 1912 PGE/100, Goodspeed/7.
65 UM 1910 PAC/100, MacNeil/5.
66 UM 1910 PAC/100, MacNeil/19.

values, in conjunction with annual QF avoided cost updates. Generation capacity, integration and environmental compliance costs should be updated upon IRP and IRP acknowledgment, as they currently are for QF avoided costs. Environmental compliance could also be updated post-IRP acknowledgment. Updates of market price response and hedging values should not vary significantly and may not require frequent updates. Administration, as stated earlier, should be updated or trued-up through program administration processes as needed.

Q. How does the QF avoided cost update process work?

A. Updates to utility avoided costs for purposes of standard QF price calculations are triggered in three ways. First, after a utility's IRP is acknowledged, the utility must file updated avoided costs within 30 days.[67] Second, a subset of avoided cost inputs are updated annually, on May 1 (forward electricity and gas prices, federal tax credit status, and acknowledged IRP Update items). Finally, utilities and other parties may file for an "out-of-cycle" update, triggered by a "significant event."[68] With the implementation of annual limited updates, the Commission has stated that the bar for out-of-cycle updates is high.[69]

[67] OAR 860-029-0080(3): "Each public utility shall file with the Commission draft avoided-cost information with its least-cost plan pursuant to Order No. 89-507 and file final avoided-cost information within 30 days of Commission acknowledgment of the least-cost plan to be effective 30 days after filing."

[68] Order No. 11-505 at 2: "A project is avoidable until a utility makes an irreversible commitment to acquire it. An irreversible commitment occurs after the completion of the RFP process and the execution of contracts or awarding of the project to the utility to build for itself."

[69] Order No. 14-058 at 25: "Finally, in light of our adoption of a yearly update, we will continue to allow requests for mid-cycle updates for significant changes to avoided cost prices. However, in light of our decision here to require annual updates in addition to

Q. Would annual updates to a utility's RVOS calculation impact existing agreements using RVOS-based pricing?

A. No. Updated values, regardless of how frequently they are updated, will be incorporated in new agreements only. Staff believes the RVOS updates would not impact established agreements.

SECTION 4: CONCLUSION

Q. What are Staff's conclusions regarding refinements or modifications to the Phase I RVOS Methodology.

A. There is insufficient information to allow further refinement to the Methodology to allow for additional granularity. Instead, the filings demonstrate that for the most part, it is appropriate to require the utilities to use methodologies employed in the past for other purposes, i.e., avoided cost determinations, for the purpose of determining RVOS. Staff appreciates the utilities' efforts to advance the granularity of the Phase I Model, but thinks these efforts should be the basis of further investigation and collaboration, rather than the basis for immediate changes to the Phase I Methodology.

Q. Please summarize any Staff recommendations for refining the Phase I RVOS Methodology.

A. Staff recommends that the Commission refine the Phase I Methodology as follows:

---

updates following IRP acknowledgement, we caution stakeholders that the "significant change" required to warrant an out-of-cycle update will be very high. We expect the parties to use this option infrequently."

- Require the utilities to report the RVOS in both real levelized and nominal levelized dollars.
- Until otherwise authorized, require the utilities to determine avoided T&D capacity value by using costs of potentially avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure, based on incremental solar penetration in Oregon service areas, without regard to location of the solar penetration.
- Until otherwise authorized, require the utilities to use the CTP of an Oregon solar resource, taken from their most recently acknowledged IRP, when determining the avoided capacity value.
- Require utilities to clearly explain any changes to the E3 model.

Q. Does Staff have any other recommendations regarding the utilities' implementation of the Phase I RVOS methodology?

A. Staff has some recommendations as to modifications to how the utilities implemented the Phase I Methodology. These recommendations are utility specific and distinct from the recommendations listed immediately above regarding the Methodology itself. Staff discusses the implementation-related recommendations in the Exhibit 200 testimony that Staff filed in each docket.

Q. Does this conclude your testimony?

A. Yes.

CASE: UM 1912
WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

March 16, 2018

Q. Please state your name, occupation, and business address.

A. My name is Brittany Andrus. I am a senior utility analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97201.

Q. Please explain the purpose of this testimony.

A. Staff addresses the Resource Value of Solar (RVOS) filing made by Portland General Electric Company (PGE) to start Phase II of the Commission's Investigation into the Resource Value of Solar (RVOS) (Docket No. UM 1716).

Q. How is your testimony organized?

A. Staff discusses PGE's implementation of the RVOS methodology adopted by the Commission at the conclusion of Phase I of Docket No. UM 1716 (the "Phase I RVOS Methodology" or "Methodology"). Staff provides recommendations as to changes PGE should make when implementing the Methodology.

Q. Did Staff discuss these recommendations in Staff Exhibit 100?

A. Yes. However, Staff did so in the context of a review of the Phase I RVOS Methodology itself and the implementation of the Methodology by PGE as well as PacifiCorp and Idaho Power company ("Idaho Power"). Staff Exhibit 100 is the same in each of the three dockets opened for Phase II of the Commission's investigation into RVOS (Docket Nos. UM 1910-12). Staff Exhibit 200 in this docket is specific to PGE.

SECTION 1: STAFF ANALYSIS PGE RVOS FILING

Q. What values did PGE provide for RVOS?

A. The values provided by PGE are set forth below.

Table 1. Standard Distributed Solar RVOS $/MWh

Element	**PGE** Real Levelized
Energy	$24.98
Generation capacity	7.30
T&D capacity	8.08
Line losses	1.48
Administration	(5.58)
Integration	(0.83)
Market price response	1.81
Hedge value	1.25
Environmental compliance	11.41
RPS compliance	0
Grid services	0
Phase II RVOS Total	$49.88

FIRST CATEGORY OF RVOS ELEMENTS:

SYSTEM ELEMENTS

ELEMENT 1, ENERGY

Q. What does Order No. 17-357 require with respect to the energy element?

A. To determine the input for energy, the utilities were required to use monthly on- and off-peak market price forecasts shaped into 12 x 24 hour blocks with energy values scaled to represent the average price under a range of hydro conditions.

Q. What forward market prices did PGE use and how did PGE shape the energy prices?

A. PGE used forward market prices that it uses for standard PURPA contracts. PGE created daily shape factor profiles for each month using hourly prices for 2024 produced by AURORA. PGE calculated the average price for each month/hour by averaging the price of each daily hour in a given month and weighting the month/hour prices by the number of days in the month and dividing by the annual average price. PGE then applied the shape factors to the weighted average annual price (based on monthly prices discussed above) for each year to create daily profiles for each month of each year (or 12 x 24 blocks).[1]

[1] PGE/200, Jordan/7-8.

Q. Does Staff believe that PGE's approach to the 12 x 24 shaping is reasonable?

A. Yes. However, in other dockets Staff has had issues with some aspects of the Aurora output as used for monthly energy prices,[2] and plans to further examine this component of the RVOS filing.

Q. Please summarize PGE's approach to shaping energy value to reflect hydro variability.

A. PGE used average generation calculated in a hydro study that spans 79 years of streamflow conditions.

Q. How does this approach ensure prices are scaled to represent average price under a range of hydro conditions?

A. This approach ensures that the price is representative of the average hydro condition, but it does not inform that the price is representative of a range of hydro conditions. Accordingly, it does not comply with the Commission's directions in Order No. 15-357.

Q. Does Staff recommend any modification to PGE's approach?

A. As discussed in Staff Exhibit 100, the methodology PGE uses should calculate market prices separately for representative random sample of hydro conditions. The average of the resulting market prices will provide an approximation of average market price under the entire distribution of hydro conditions.

Q. What is Staff's assessment of the solar generation profile used by PGE?

A. Staff is satisfied that PGE chose a reasonable generation profile.

[2] See Staff Report in Docket No. UM 1728, September 17, 2017.

ELEMENT 2, GENERATION CAPACITY

Q. What did the Commission require from the utilities for avoided generation capacity?

A. The Commission directed utilities to determine the avoided capacity value consistently with the Commission's standard nonrenewable QF avoided cost guidelines. 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 cost of a utility's avoided proxy resource.

Q. How did PGE determine the value of avoided generation capacity?

A. PGE used the levelized fixed cost of a single cycle combustion turbine from its 2016 IRP, and multiplied this value by the CTP at an assumed solar penetration level from its 2016 IRP.[3] Staff notes that for QF pricing, PGE's CTP results are applied differently than they are for Idaho Power and PacifiCorp.

Q. Please explain this difference.

A. PGE, in its QF Schedule 201, applies a CTP value that varies with the amount of solar generation on its system, and that amount of solar contracted to come on to its system. For current QF pricing and the company's RVOS filing, the CTP is based on a solar penetration level of 200 to 300 MW, 15.33 percent.

Q. Does PGE's method comport with the method for valuing capacity in Order No. 17-357?

A. Staff believes that the element has been sufficiently addressed for the purpose of implementing the Phase I Methodology.

[3] Portland General Electric 2016 Integrated Resource Plan, p. 127, Figure 5-11.

Q. The Commission directed each of the utilities to run sensitivities analysis to determine what level of solar PV penetration has a material effect on the load resource balance. Did PGE do this?

A. PGE testifies that it did not perform the sensitivities analysis because it makes no explicit assumptions about incremental distributed solar PV as part of the load forecasting process. PGE testifies, "[t]he impact of existing distributed solar is included in PGE's historical energy deliveries data and as such is embedded within PGE's regression based load forecast."4

Given the low level of distributed solar penetration, Staff believes that PGE's response to the Commission's direction regarding sensitivities analysis is adequate.

ELEMENT 6, INTEGRATION COSTS

Q. What did the Commission require from the utilities for this element?

A. The Commission directed utilities to make estimates of integration costs based on acknowledged integration studies.

Q. What value did PGE use for integration in its RVOS filings and what is the basis for this value?

A. PGE's value for integration costs is based on variable integration cost as calculated in its 2016 IRP.[5] This section of the 2016 IRP describes PGE's variable energy integration (VER) study, which is based on a series of model "runs" that include the integration of different combinations of variable resources, including wind and solar. PGE uses the VER study result of $0.83 (2016$) as its solar integration value.

Q. Does Staff believe this value is appropriate for RVOS integration costs?

---

[4] UM 1912 PGE/200, Jordan/6.

[5] PGE/100, Goodspeed/11, reference to Section 7.2.1.1-7.2.1.2 of PGE 2016 IRP.

A. Because the VER result accounts for the integration cost of variable resources other than solar, it should not be used as-is for RVOS. Staff believes PGE should develop a method for allocating VER integration costs to specific variable resource types.

SECOND CATEGORY OF RVOS ELEMENTS: LOCATION-SPECIFIC SYSTEM ELEMENTS

ELEMENT 3, TRANSMISSION AND DISTRIBUTION CAPACITY

Q. What did the Commission expect from the utilities for this element?

A. The Commission directed utilities to develop a system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration in Oregon service areas. The Commission allowed utilities to use their Marginal Cost of Service Studies to estimate avoidable T&D costs for the RVOS, but did not require it. The Commission also directed utilities to comment on how their distribution planning could advance the granularity of this element for the next iteration of RVOS.

Q. Did the Company adopt the marginal cost of service T&D avoided cost for the RVOS?

A. Yes. The Company used a system-average calculation of deferring the value of expanding, replacing, or upgrading T&D investments. For distribution numbers, PGE used the marginal cost study from the 2018 rate case, Docket No. UE 319. For transmission numbers, the Company used the value from BPA’s 2018 tariffed Firm Point-to-Point transmission service with Scheduling, System Control, and Dispatch Service. The combined value is $21.52 per KW-year for

2018. Escalation rates for both transmission and distribution are estimated to be 2%, which is consistent with the 2016 IRP.[6]

Q. Please summarize the Company's comments on locational granularity.

A. The Company stresses that it analyzes T&D capacity needs based on system peaks, and outlines the activities of the asset management strategy department called SAM (Strategic Asset Management). PGE does not go into great detail but generally describes one of the functions of the SAM department as identifying high-risk infrastructure and the need for system reinvestment. For example, should solar resources coincide with system peaks on a stressed piece of equipment such as a feeder or transformer, solar resources could defer investment on that piece of equipment by reducing load at peak. In this sense, Staff interprets PGE's testimony to describe a process by which SAM could identify areas where solar resources provide a deferral value.

Q. For locational granularity, does Staff believe that the Company has complied with Order No. 17-357?

A. Yes.

Q. Does Staff have a recommendation regarding PGE's determination of the T&D capacity element for RVOS?

A. Staff believes that the method PGE employed is reasonable and complies with Order No. 17-357.

ELEMENT 4, LINE LOSSES

Q. What did the Commission expect from the utilities for this element?

A. The Commission directed the utilities to develop hourly averages of avoided marginal line losses attributable to increased penetration of solar PV systems in

---

[6] PGE/400, Murtough/7-8.

Oregon service areas. The incremental line loss estimates shall reflect the hours solar PV systems are generating electricity.

Q. How did PGE address the avoided line losses element?

A. PGE calculated seasonal and high- and light-load line loss data. PGE captured losses for each distribution power transformer in substations, as well as each of their corresponding distribution feeders. For the distribution feeders, losses were calculated for all primary circuits. Utilization transformers, secondary, or service wires were not included in this study.[7]

Q. What are Staff's conclusion regarding PGE's determinations of the RVOS for avoided line losses?

A. Staff believes PGE's implementation of the line loss element is reasonable and complies with Order No. 17-357.

THIRD CATEGORY OF RVOS ELEMENTS: NON-SYSTEM ELEMENTS

ELEMENT 5, ADMINISTRATION

Q. What did the Commission require the utilities to do for this element?

A. The Commission directed utilities to develop estimates of the direct, incremental costs of administering solar PV programs including staff, software, incremental distribution investments, and other utility costs

Q. How did PGE address the administration element?

A. PGE states that its value for administration is based on an estimate of the direct incremental costs of administering solar PV programs, including staff, software, incremental distribution investments, and other utility costs.[8]

[7] PGE/400, Murtough/4-5.

[8] PGE/100, Goodspeed/5.

Q. Does Staff have any recommendations regarding PGEs implementation of the Phase I RVOS Methodology with respect to the Administration element?

A. Not at this time.

ELEMENT 7, MARKET PRICE RESPONSE

Q. Please summarize the Commission's directions to the utilities for this element.

A. The Commission directed Staff to coordinate or facilitate use of E3's model to create a proxy value for market price response that utilities will use in their initial RVOS filings.

Q. What is PGE's MPR value?

A. PGE estimates MPR to be worth between $1.61-1.81/MWh in real (2017) levelized dollars, depending on the amount of solar penetration (100 – 1000 MW).[9]

Q. How did PGE calculate its MPR value?

A. PGE used its AURORA model to run two scenarios with differing assumptions regarding solar penetration within the WECC region - 100 MW and 1000MW. For both runs, PGE simulated wholesale power markets prices in the WECC from 2020-2045. Within the simulation, solar resources were added to the WECC's regional resources, not to PGE's portfolio.[10]

Q. Does PGE's methodology differ from that suggested by E3?

A. Yes. The E3 methodology estimates an average impact on annual solar-hours Mid-C prices under a specified level of solar penetration. The wholesale price impact of this incremental solar is estimated to be constant across the years

[9] PGE/300, Sims/8-10.

[10] PGE'300, Sims/8-10.

included in the study. The price impact during solar hours are multiplied by the net purchases or sales that a utility transactions in the Mid-C market.

PGE's methodology calculates E3's forecasted portfolio on an hourly basis and measures how those costs are affected by a specified level of solar penetration. PGE testifies that by measuring this impact on portfolio costs, PGE attempts to capture the MPR impact on the volume and value of market purchases and sales.

Q. Does Staff agree with PGE's concern[11] about the possibility of double counting the MPR in RVOS?

A. Staff agrees that there is a potential double-counting the value of solar: if there is a positive value associated with the MPR derived from reduced wholesale prices, then there should also be a reduction in energy (avoided cost) value. A reduction in the marginal cost of wholesale energy prices reduces the costs avoided by solar generation, and that reduction should be reflected in the energy value.

ELEMENT 8, HEDGE VALUE

Q. Please summarize the Commission's directions to the utilities for this element.

A. The Commission directed utilities to assign a proxy value of 5 percent of energy.

Q. What is PGE's hedge value?

A. PGE estimates hedge value to be worth $1.25/MWh in 2017 levelized dollars.[12]

Q. How did PGE calculate this value?

[11] PGE/300, Sims/10.

[12] PGE/100, Goodspeed/7.

A. PGE used the Commission- and E3-recommended five percent value of energy.[13]

Q. Does PGE have any concerns with this calculation?

A. Yes. PGE does not believe the process noted above accurately reflects its hedging strategy. PGE highlights that in the analysis that generated the five percent proxy value, the time period and gas hub used are not representative. Further, PGE notes the methodology does not take into account PGE that PGE layers its hedges throughout a year.[14]

Q. Does Staff believe that PGE's concerns justify a new calculation?

A. Not at this point. The marginal benefits of new analysis (namely a more accurate hedging value representation in RVOS) would not likely equal the costs of updating the analysis performed in DeBenedictus et al. (2011) study. Staff views the five % proxy as the best available information. It relevant here to note that PGE estimates that hedging value represents ~2.5 percent of the total RVOS value: fine-tuning this in the future would likely provide some benefit, but it will not greatly affect the final RVOS value.

ELEMENT 9, ENVIRONMENTAL COMPLIANCE

Q. Please summarize the directions to the utilities for this element.

A. The Commission directed the utilities, for informational purposes, to estimate the avoided cost based on a reduction in carbon emissions from the marginal generating unit. To value future anticipated standards utilities should use the carbon regulation assumptions from their IRP.

[13] PGE/300, Sims/3.

[14] PGE/300, Sims/4-6.

Q. How did PGE calculate the avoided environmental compliance value for RVOS?

A. PGE utilized the mid-national carbon price forecast from Docket No. LC 66 – PGE's 2017 IRP. The forecast was published by Synapse Energy Economics in its "Spring 2016 National Carbon Dioxide Price Forecast." This forecast is included as PGE/501.[15]

Q. Does Staff have concerns with this methodology?

A. No.

SECTION 2: CONCLUSION

Q. Please summarize Staff recommendations related to PGE's implementation of the RVOS Methodology.

A. Staff recommends that PGE:

- modify its hydro variability modeling to conform to Order No. 17-357.
- ensure its integration cost value is for solar costs rather than integration costs of all variable resources.

Q. Does this conclude your testimony?

A. Yes.

[15] PGE 2016 IRP, Chapter 3.