CASE: UM 1716
WITNESS: MARK BASSETT

PUBLIC UTILITY COMMISSION OF OREGON

Testimony of Mark Bassett

On behalf of

Oregon Public Utility Commission

Testimony

May 5, 2017

Q. Please state your name, and business address.

A. I am Mark Bassett. My business address is 201 High Street SE, Suite 100, Salem, OR, 97301.

Q. Please describe your background and work experience.

A. I am employed as a Senior Renewable Energy Analyst at the Public Utility Commission of Oregon. My witness qualification statement is found in exhibit Staff/501.

Q. On whose behalf are you testifying in this proceeding?

A. I present testimony on behalf of Staff of the Public Utility Commission of Oregon.

Q. What topics will this testimony address?

A. I provide Staff's response to the Commission's Straw Proposal determining the elements that should be valued in the resource value of solar (RVOS) and the methodologies that should be used to value them. I also provide Staff's proposal as to how to proceed with Phase II of this investigation.

I also append to my testimony written responses drafted by E3 in response to the questions presented in Appendix A of Order No. 16-404.

Q. Please describe the procedural background of this docket.

A. In 2015, the Commission initiated an investigation into how to determine the RVOS and the extent of cost-shifting, if any, from net metering, and to evaluating the reliability and operational impacts of increasing levels of solar generation.

The Commission has since entered an order closing its evaluation of the reliability and operational impacts of solar generation[1] and has put the examination into cost-shifting on hold pending a Commission determination of RVOS for each utility.[2]

In July 2015, Staff submitted a list of 26 “elements” of solar generation that could potentially be evaluated to determine the RVOS and asked the Commission for a determination of which elements should be included in the RVOS. Parties filed comments regarding their recommendations as to which elements the Commission should include.

Q. Did the Commission decide which elements to include in the RVOS?

A. No, the Commission declined to make such a determination, concluding that it would decide which elements to include in the model at the same time it determined the methodologies for valuing them.[3] But, the Commission clarified that it would only include elements in the RVOS “that could directly impact the cost of service to utility customers.”[4] The Commission gave examples, noting “we would consider the potential financial costs to utilities of future carbon regulation,” and “[o]n the other hand, for example, we will not consider job impacts of solar development.”[5]

The Commission directed Staff to determine a procedural process that would allow the Commission to select the elements and methodologies for the

[1] Order No. 16-074 (January15, 2016).
[2] UM 1716 Ruling (February 29, 2016).
[3] Order No. 15-296 at 2.
[4] Order No. 15-296 at 2.
[5] Order No. 15-296 at 2.

RVOS and authorized Staff to hire a consultant to assist in evaluating which elements should be included in the RVOS and to develop methodologies to evaluate the elements.

Q. Did Staff hire a consultant?

A. Yes. Staff issued a Request for Proposals and ultimately contracted with Energy and Environmental Economics, Inc. (E3), to create a methodology for calculating RVOS based on elements that could directly impact the cost of service to utility customers. Staff Exhibit 200 is testimony of Arne Olson, a partner at E3, which presents the methodology.

Q. Has E3 run the model to produce RVOS values for each of the utilities?

A. No. The Commission previously ordered that it would not determine RVOS values for the utilities in the first phase of this investigation. The Commission stated:

> We envision a two-phase process. The first phase will examine elements and methodologies. The second phase will examine values for each utility using those adopted methodologies.[6]

E3 has produced some sample model runs to illustrate the use of the model, but the resulting RVOS values are not based specifically on information from any one utility.

Q. Have parties testified regarding the methodology created by E3?

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[6] Order No. 15-296 at 2.

A. Yes. Parties submitted two rounds of testimony regarding the methodology. And, the Commission held a hearing on January 31, 2017, largely for the purpose of hearing directly from parties and the Staff expert, Arne Olson, on responses to specific questions posed to the parties in Order No. 16-404.

Q. **Does Staff have concerns with the Commission's Straw Proposal?**

A. Not at this time. Staff reserves the opportunity to address other parties' comments on the Straw Proposal, which may include interpretations of the proposal that differ from those of Staff.

Q. Does Staff have a recommendation as to how to proceed in Phase II?

Yes.

- Utilities have six months[7] from the date of the order resolving Phase I ("Phase I Order") to develop the values specified in the order, including the alternative estimate of RVOS using a utility scale solar resource. At the conclusion of the six-month period, the utilities will circulate the values to parties informally (meaning not filed with Filing Center), along with the supporting documentation.
- Within three months of the Phase I Order, Staff will conduct workshops to develop methodologies for valuing market price response and hedge value. If the parties are able to agree upon a methodology to value market price response, the utilities will include a value for market price response based on the agreed-upon

[7] The six-month period is a placeholder and used to avoid confusion with other time intervals discussed in this proposal.

methodology when they circulate the other values at the conclusion of the six-month period. If the parties are not able to agree to a methodology, the utilities will propose a value for market price response using at least one of the methodologies discussed by parties. The utilities will include a hedge value based on the methodology recommended by Staff.

- After the utilities circulate their proposed values for RVOS including the alternative value of utility-scale solar, Staff will hold a technical conference/workshop for parties to discuss the utility proposals and parties may offer utilities recommendations for changes.
- Following the workshop, parties will ask for a telephonic prehearing conference to establish the remainder of the procedural schedule. The procedural schedule should commence with the utilities filing testimony describing their proposed values and providing supporting documentation. The utilities' testimony should be followed by testimony by all other parties responding to the utilities' proposals, and then an opportunity for all parties to file cross-responsive testimony.
- Following testimony, parties will have opportunity for a hearing and briefing.
- After the evidentiary stage is concluded, the Commission will issue a Phase II order finally determining the methods each utility should

use to determine RVOS for mass-market solar facilities available to utility customers and for utility-scale solar.

Q. Does this conclude your testimony?

A. Yes

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PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 501

Staff Witness Qualifications Statement

May 5, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mark Bassett
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Renewable Energy Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE, Suite 100 Salem, OR 97301
EDUCATION:	Bachelor of Science, Renewable Energy Engineering Oregon Institute of Technology, Klamath Falls, OR Certified Energy Manager (C.E.M.) Certification Association of Energy Engineers, #22998
EXPERIENCE:	I have eight years of experience in renewable energy (RE) system design, evaluation, and research. Prior to joining the PUC in 2017, I worked for four years as a RE system designer, and three years at the U.S. Department of Energy's Pacific Northwest National Laboratory, where I was a subject matter expert for RE technologies. I performed RE site assessments and economic analysis; performed building energy audits; researched and qualified RE technology; wrote guidelines for RE O&M, monitoring, and policy; wrote technical reports; and peer reviewed other staff's reports. As the Senior Renewable Energy Analyst at the PUC, I provide technical expertise and regulation support on a variety of RE-related programs.

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STAFF EXHIBIT 502

Exhibits in Support
Of All-Party Opening Testimony

May 5, 2017

E3 Responses to Commission Questions

Energy and Capacity Elements

1. Should the Commission require all utilities to provide the forecasted value of avoided energy costs on an hourly basis?

Yes.

a. What is the gain in precision by doing so?

Using confidential data provided to E3 by the utilities during the initial phase of the RVOS methodology, E3 calculates that using hourly energy values increases the energy RVOS element by approximately 10% relative to using an annual average cost of energy. This result is based on the hourly data provided by PacifiCorp. Idaho Power and PGE both provided energy values by on/off peak period and did not vary by hour.

The gain in precision from hourly data is highly dependent upon energy price profile, which is especially sensitive to the underlying generation portfolio including RPS percentage and RPS resource mix i.e. solar vs. wind.

In California, solar penetrations have now increased to such a significant portion of the portfolio that using hourly energy values decreases the energy RVOS element by approximately 10%. The data used to calculate this value is based on the publicly available California Public Utilities Commission Avoided Cost Calculator.[1] As penetrations of both utility-scale and behind-the-meter solar increase in Oregon, I would expect a similar change in the relationship of hourly results vs an annual average.

b. What is the cost of doing so?

The tools to create an hourly set of marginal energy prices are readily available in the utility industry, and it is standard practice for utilities to utilize these hourly energy values in their integrated resource planning processes. Therefore, I do not believe that instituting this requirement would impose an undue or significant additional cost on the utilities.

2. Utilities model a range of hydro conditions to generate an estimate of the avoided cost of energy.

a. Is that sufficient?

Accurately estimating future marginal energy prices necessitates modeling a range of hydro conditions. It is E3's intent that the RVOS methodology will incorporate the expected value of marginal energy prices under a range of hydro conditions.

The reason it is necessary to model a range of hydro conditions is because high and low hydro conditions may not have a symmetric impact on marginal energy prices relative to a normal hydro year. In other words, low hydro conditions may increase energy prices much more than

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[1] http://www.cpuc.ca.gov/General.aspx?id=10710

high hydro conditions decrease them. This concept, known as the flaw of averages[2], is well established in many industries and stipulates that the output value of the average input is not equal to the average output of all inputs.

Therefore, it is E3's intent that the hourly marginal energy prices profiles that are used in the RVOS are scaled to represent the average price under a range of hydro conditions.

b. If not, why not and what modelling should the utilities be doing and how should the results for different hydro conditions be presented?

See above

3. Should the Commission require the utilities to use a resource sufficiency/deficiency demarcation as is now used to generate QF avoided costs?

Yes, a resource sufficiency/deficiency demarcation is necessary to ensure that the RVOS correctly measures value that solar actually provides to utility ratepayers.

a. If so, should the Commission require the utilities to revisit the demarcation timing assuming that forward-looking incremental solar PV generation additions are not included as a reduction in the load used to determine the demarcation?

For the purpose of the RVOS, solar should NOT be included in calculating the resource sufficiency/deficiency demarcation. This ensures that the RVOS is accurately calculated relative to a world where this solar did not exist.

b. Should the Commission require the utilities to value avoided energy costs during a resource sufficiency period as currently set forth in the Commission's QF avoided cost rules?

Yes.

c. If not, what changes should be made and why?

See above.

Transmission and Distribution Capacity Element

4. Should utilities estimate the value of solar to defer or eliminate the need for T&D upgrades solely when an upgrade is required to meet load growth?

Utilities should estimate the value of solar to defer or eliminate the need for *all* T&D upgrades. In most cases, this value will be tied to load growth i.e. deferring the need to install a larger transformer to accommodate growth in a particular area. However, T&D value does not need to be limited to this circumstance.

[2] http://flawofaverages.com/

5. Some argue that increased solar generation could increase distribution system O&M expenditures.

a. What empirical evidence exists or could be generated to support that assertion?

This is a question for the utilities.

b. The transmission and distribution capacity value is highly location-dependent. Given available data, should the Commission consider using a system-wide average as a proxy and why or why not?

This depends on how the Commission will ultimately use the RVOS. If the RVOS will be used to compensate solar generators, location-dependent values will incentivize solar to be installed in the most optimal locations and will ensure that utility ratepayers are accurately compensating solar generators for the value they provide. If the RVOS will be used on an ex-post basis to measure the aggregate value provided by solar generators across the state, then a system-wide average would sufficiently accomplish this.

c. Given available data, are there ways to differentiate value by geographic area that would provide more accurate estimates by area? (by "geographic area", we are not necessarily assuming down to the individual feeder level but rather if there is a geographical area designation between the entire system (and use of a system wide average) and feeder level that could be used to derive area-specific values.)

This is a question for the utilities. However I believe that it would be possible for the utility to differentiate by geographic area.

d. What additional data would need to be collected to derive a more accurate T&D capacity value by area?

The utilities would need to compile their capital expenditure plans in each area and then assess which of these expenditures could be deferred or avoided due to solar within those areas.

e. What additional work or investment would be required to collect additional data to calculate location-specific values?

This is a question for utilities.

<u>**Administrative Costs and Line Losses**</u>

6. With small variations in approach, there seems to be general agreement on the valuation of administrative costs and line losses. Should the method for calculating incremental administrative costs and line losses be left to utilities as long as each utility provides sufficient justification for the method used and value derived?

The utilities should ideally calculate marginal line losses on an hourly basis. Because line losses increase non-linearly with system load, marginal losses will be greater than average losses.

Additionally, measuring marginal losses on an hourly basis will increase RVOS accuracy because it will capture the alignment of solar production with the hourly change in loads which affect marginal line losses.

To the extent that the utilities deviate from this (e.g. by providing marginal losses on a less time granular basis or by providing average losses instead of marginal losses), they should be prepared to justify their rationale and the estimated impact to the RVOS.

Market Price Response

7. Should utilities estimate both the impact of lower wholesale prices on customer costs and lower surplus sales revenue?

Yes, both of these impacts should be taken into account.

a. There appears to be no ready empirical research or quantitative formula for determining a reasonably accurate measure of the impact of increased solar generation in Oregon on regional wholesale power sale prices. Should the Commission require the use of a proxy method?

Yes, the Commission should require the use of a proxy method to estimate this impact.

b. If yes, what should be the basis of that method and what evidence exists to back up a proxy method?

There have been several studies that attempt to estimate this impact including a study by myself and my colleagues at E3. Specifically, I have analyzed the impact of increasing wind penetrations on the marginal price of energy at the Mid-Columbia trading hub. Although wind and solar have different production profiles, they are both zero marginal cost resources that could be reasonably inferred to have a similar impact on marginal energy prices. Therefore, I believe this is a reasonable proxy method. Other stakeholders may have alternative approaches that could be well suited to the task as well.

c. What research and modelling work, if any, should the Commission require and by whom to generate a workable calculation formula?

This element of the RVOS, in all likelihood, will be a very small portion of the total RVOS. Therefore, I do not believe significant resources should be expended to more accurately quantify this element relative to a proxy method. Ultimately, the requirement of such work would likely cost utility ratepayers more than the benefit of increased accuracy in this element.

Avoided Hedge Value

8. In general, the utilities disagree with the proposed hedge value calculation formula and argue that hedge value should be set to zero based on their hedging policies and other factors.

a. Do other parties agree or disagree with these assertions and why?

In general, customers have a preference for stable prices relative to volatile prices. In fact, customers are willing to pay more for stability, and many utility commissions across the country have instituted hedging policies that reflect this. These hedging products often come with a risk premium to factor in the risk that is being transferred from the utility to the counterparty. To the extent that the natural gas prices that underlie the energy prices in the RVOS do not take into account this risk premium, the proper place to account for this value to customers is through a hedge value.

b. What research and modelling work, if any, should the Commission require and by whom to generate a workable calculation formula?

I believe this element is to be small relative to the aggregate RVOS. Therefore, I believe a proxy value equal to 5% of energy is sufficient to capture this hedge value effect. As with market price response, I believe expending additional resources to more accurately quantify this value would likely cost ratepayers more than the benefit of increased accuracy for this element.

<u>Avoided Renewable Portfolio Standard Compliance</u>

9. There appears to be some agreement that a valuation of avoided RPS compliance should be based on a reduction in load due to increased solar PV generation.

a. Do you agree or disagree that this should be the basis of a value formula and why?

I agree that this should be the basis of a value formula.

b. Is there a straightforward methodological approach that would generate reasonably accurate values?

The proposed E3 methodology is relatively straightforward and generates reasonable accurate values. Simply put, the proposed methodology for this element is equal to the RPS Premium multiplied by the RPS percentage. The RPS premium is calculated as the cost of an RPS contract minus the market value of the energy and capacity that the resource provides. This value is multiplied by the RPS % in order to link the reduction in load due to solar generation to the reduction in the utility RPS compliance obligation. For example, if the customer reduces loads by 1 kWh and the RPS requirement is 40%, the utility sees a decrease in RPS requirement obligation of 0.4 kWh. For more specifics and nuance on this methodology, please see my original testimony.

c. Assuming each utility has enough banked RECs to meet current compliance projects for at least the next five years, how should this value of avoided RPS compliance cost from a newly installed PV system in 2017 be calculated?

Because RECs can be banked into the future, the avoided RPS *<u>quantity</u>* is not affected the utility's net short/long RPS position. However, the *<u>value</u>* of the RPS Premium is affected. The RPS Premium should be calculated based on expected price of RECs when the utility needs to procure additional RPS energy. These factors are accounted for in the proposed E3 methodology as outlined in my original testimony.

d. Should this value be applied only for the future years in which actual deferral of renewable resource procurement to meet compliance will be realized?

See previous answer

e. Utilities reassess their RPS implementation plans every two years for the next five years. Does this reassessment of need have any bearing on the calculation of this element?

No, this should not have any bearing.

f. Is a simplified approach such as what is proposed by E3 reasonably accurate in assessing this value?

Yes, I believe the approach proposed in my original testimony is reasonable accurate in assessing this value.

<u>Carbon Compliance Assumptions</u>

No response.

<u>Integration and Ancillary Services</u>

11. Increased solar generation could either increase or reduce (with smart technologies) the need for grid services depending on the specific circumstances. What specific grid services should we focus on?

There are three specific impacts of solar that I would like to address: integration costs, a reduction in ancillary service requirements, and providing ancillary services

Integration Costs

Since solar increases the variability of loads on the system, the utility must hold additional reserves in order to accommodate unforeseen fluctuations in system loads.

Ancillary Service Requirement Reduction

Because solar reduces total loads on the system and ancillary service requirements are tied to total system loads, solar provides value by avoiding some ancillary service requirements. In my original testimony, I grouped integration costs and this ancillary service benefit together into one element for simplicity. However these elements can also be separated into individual elements. The model currently calculates this element as 1% of avoided energy value which is a very small fraction of the total RVOS.

Providing Ancillary Services

Generating resources can provide different energy products including energy, capacity, and ancillary services. Typically, generating plants must choose between offering energy or ancillary services as they are to some extent mutually exclusive from one another. Solar generators could also offer ancillary services such as regulation up, regulation down, or load following services, but this would require advanced infrastructure beyond the standard mass-market installation package and would come at the expense of other RVOS elements such as energy and capacity. For example, providing regulation up services would necessarily entail curtailing energy on a regular basis in order to ramp up output on demand by uncurtailing generation. Because the RVOS quantified in the proposed E3 methodology is for a standard mass market solar generator, I do not believe it is appropriate to include the potential value of providing ancillary services as an element.

a. Are the potential benefits and costs location-specific?

The location-specific factors that would affect these components are similar to the factors that would affect the locational value of energy. These locational differences are generally much smaller than the locational values from T&D infrastructure.

b. What additional research or modelling is necessary to properly value grid services?

The utilities have already done work to quantify the integration costs of renewable resources. I believe that measuring the reduction in ancillary service requirements by multiplying energy value by 1% is sufficient and reasonable given the small fraction this element comprises of the RVOS.

<u>Security, Reliability, and Reserves</u>

12. Parties appear to disagree on the definition of system security and resiliency set forth by E3. What potential resiliency and reliability benefits does solar PV generation potentially provide to the utility system?

Solar generators that are installed with advanced an uncommon infrastructure such as microgrids are capable of islanding during an outage event and continuing to provide electricity to the solar microgrid customer. In this event, all of the security and reliability value accrues to the customer who owns the microgrid. This value does not benefit general utility ratepayers, and therefore should not be included in the RVOS.

a. Are any of those potential benefits captured in other valuation categories?

As described, “security and reliability” benefits accrue to the microgrid customer. I would classify “reserve” benefits in the same category as ancillary services where they are appropriately accounted for.

b. How should these benefits be valued?

As mentioned, security and reliability benefits should not be valued in the RVOS, while reserve benefits are already accounted for in the ancillary services element.

c. Is there available data or analysis that would inform an assessment of these values?

See above.

General Issues

13. There appear to be disagreements on valuation when there is uncertainty.

The RVOS should reflect the expected value of future price streams. For two RVOS elements, energy and carbon compliance, my comments address how I believe to account for this uncertainty.

a. What criteria should the Commission use to assign a non-zero value or zero value to an element when a value is uncertain?

The Commission should not use uncertainty as a reason for assigning zero value unless there is a large probability that the value is zero. Rather, the Commission should use proxy values or placeholder values where necessary to estimate the value from certain elements. My testimony makes reference to proxy methods such as using the marginal cost of distribution as a proxy value for avoidable distribution infrastructure costs.

b. Should utilities assign values based on the technology of the solar systems (e.g. solar PV systems with or without smart inverters) that are installed the year a calculation is made?

If the utility plans to utilize customer-owned smart inverters in a way that would benefit general utility ratepayers (such as controlling output to provide ancillary services), then a separate RVOS should be calculated for these customers. If the utility plans to utilize customer-owned smart inverters to mitigate incremental costs that are caused by the solar installations themselves, then this value should not be included in the RVOS.

Other technology specific factors that affect the output value of the solar system are implicitly accounted for in the hourly nature of the RVOS. For example, a tracking solar system that produces more energy during certain hours receives more value in the proposed RVOS methodology.

c. What should we require to obtain location-specific values or reasonable proxies of locational values?

If the RVOS will be used for compensation to solar customers, more location-specific values will lead to more optimal installation of solar systems and better value to utility ratepayers. In this case, it may be worth requiring utilities to provide locational values to a very granular level, possibly the feeder level. This would likely require significant work and would be a similar endeavor to the California Distribution Resource Planning (DRP) process or the New York Reforming the Energy Vision (REV).

d. What should be the time frame for analyses and why?

I believe that a 30 year levelized RVOS that is re-calculated annually and applied to that vintage of solar installations is appropriate. For example, in 2018 the RVOS would be calculated and fixed for 30 years for all systems installed in 2018. In 2019, the RVOS would be calculated and fixed for 30 years for all systems installed in 2019.

This approach provides certainty and stability for both the solar generators and the utility and is not wholly dissimilar from the fixed price contracts that the utility signs for large-scale renewable generation. This levelized approach also simplifies issues such as the resource sufficiency/deficiency demarcation which are complicated in an annual calculation.

e. What should be the time period for a levelization calculation?

I believe that 30 years is a reasonable time period for a levelization calculation. This value is based on a reasonable expectation for the lifetime of a solar installation. To the extent that production decreases in later years, the variable nature of the RVOS will compensate the solar generator accordingly less.

f. How often should values be updated?

As stated earlier, the RVOS should be updated annually and should apply to all solar systems installed in that year.

g. What level of granularity and transparency should we require and why?

The model should ideally operate on an hourly basis as the proposed E3 methodology outlines. To the best effort of the utilities, they should use data that can be made available to the public to create a transparent RVOS.