BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1716

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation to Determine the Resource Value of Solar.	ORDER

DISPOSITION: STRAW PROPOSAL MODIFIED AND ADOPTED, PHASE I CLOSED, ADDITIONAL PROCEEDINGS ORDERED

In this order, we complete Phase I of this proceeding by modifying and adopting the attached matrix, that contains the elements, definitions, and inputs from the utilities for initial calculations for the resource value of solar (RVOS). We direct the utilities to develop initial RVOS calculations and file them in new, utility-specific dockets by November 30, 2017.

I. SUMMARY

In Order No. 17-085, we set forth a RVOS straw proposal that included, for each element, a definition, calculation methodology, and next steps. After we issued the Straw Proposal, we invited the parties to provide two more rounds of testimony.[1]

This order completes Phase I of this docket by summarizing the latest testimony and finalizing our decisions on the RVOS definitions and inputs from the utilities.[2] We largely adopt the RVOS methodology proposed by E3 to produce a 25-year marginal, levelized value for a generic, small-scale solar resource installed in 2017.

[1] The following parties/witnesses provided testimony in response to the Straw Proposal: Mark Bassett for Staff (Staff attached E3/Arne Olson's responses from the January hearing as an exhibit); Darren Murtaugh and Jacob Goodspeed for Portland General Electric; Rick Link for PacifiCorp, dba Pacific Power; Michael Youngblood for Idaho Power Company; Michael O'Brien for Renewable Northwest (Renewable NW), the NW Energy Coalition (NWEC), Northwest Sustainable Energy for Economic Development (NW SEED); and the Oregon Solar Industries Association (OSEIA); Bob Jenks for Oregon Citizens' Utility Board (CUB); Eliah Gilfenbaum for the Alliance for Solar Choice (TASC); and Jesse Ratcliffe for Oregon Department of Energy (ODOE).

[2] Order No. 15-296 at 2 (Sep 28, 2015) ("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.").

This order adopts 11 elements for the RVOS calculation. Four elements make up the majority of the calculation: energy, generation capacity, transmission and distribution capacity, and line losses. The values of these four elements will largely come from the utilities' existing avoided cost prices or existing cost studies, with additional granularity to properly value the shape of solar production. Because these elements are a large portion of the RVOS value, we ask the utilities to provide a narrative explanation on each element. For energy, we ask for a detailed explanation of how the utilities create their 12 x 24 block, as well as an explanation and analysis demonstrating how energy values are scaled to represent the average price under a range of hydro conditions. For capacity, we maintain our standard practice but ask Staff to conduct a future workshop to discuss ways to value incremental capacity additions during resource sufficiency. For transmission and distribution, we ask the utilities to explain what they can do in the near term to advance toward more location-specific values for this element, starting from their current information and methodologies. Finally, for line losses, we ask the utilities to explain how they reflect daily and seasonal variation in their marginal line losses calculation.

Two of the elements are costs to the utility: integration and administration, and the values for these two elements will also come from existing utility studies. We ask the utilities to include a narrative explanation and justification of their administration costs. For integration, utilities will use inputs from integration studies. We group ancillary services, which previously was grouped with integration, into the last element now called "grid services." We note TASC's interest in solar photovoltaic (PV) paired with storage, and we invite TASC to file a proposal on how we could value solar paired with storage in a future version of RVOS.

Two of the elements will use a proxy value as suggested by E3: hedge value and market price response. One element, environmental compliance, will be treated as an informational placeholder in initial RVOS Phase II filings.

The last two elements will be valued at zero in the utilities initial RVOS Phase II filings: RPS compliance, and grid services. For RPS compliance, we intend to assign a methodology before the end of Phase II. For grid services, we invite Renewable NW or other parties to file a proposal on how to value smart inverters in a future version of RVOS but do not intend to assign a value before the end of Phase II.

To begin Phase II, we direct the utilities to make individual compliance filings in new utility-specific dockets by November 30, 2017, using the inputs decided here and the methodologies more specifically described by E3's formulas. The narrative explanatory information we ask the utilities to include in their initial testimony will build a robust record for Commission decision on the final RVOS. Below we also describe the utility-scale proxy alternative the utilities are to file, the implementation workshop Staff is to conduct, and the proposed timeline for RVOS in 2018.

II. DISCUSSION

We first address the 11 elements for the RVOS calculation. For each we summarize the party's arguments and provide our resolution on definitions and methodologies. We then address two general issues listed as bullet points at the end of the matrix: levelization period, and the alternative utility-scale estimate of RVOS. These issues will help inform the utilities' compliance filings and consideration of future RVOS issues. Finally we look toward Phase II, and set out the procedure and timing of future activities related to RVOS.

A. Avoided Energy

1. Granularity

The straw proposal described a marginal avoided energy value with utilities using current QF avoided cost pricing which is published in monthly or annual on and off-peak blocks. The straw proposal also proposed that Staff convene workshops to examine the need for and costs of modeling to estimate energy at a smaller time interval.

a. Party Testimony

Idaho Power and PacifiCorp seek clarification that their existing avoided cost methodology and IRP assumptions are satisfactory to calculate avoided energy. PacifiCorp proposes to use its non-standard QF methodology—PDDRR—which calculates the marginal cost of a specific resource on its system. PacifiCorp maintains that its non-standard methodology is a more accurate estimate of energy, whereas its standard pricing uses simplified assumptions. PacifiCorp states it is important for RVOS and avoided cost methodology to be consistent so that solar developers are not choosing between different price streams. Idaho Power proposes to use its ICIRP methodology that looks at the resource stack serving load in each hour and assign the cost of the utility's marginal displaceable resource in the hours that solar provides generation. PGE states that it does not currently forecast energy on an hourly basis and it believes that any value gained through hourly forecasting is traded off by increased administrative burdens.

Renewable NW and Staff state that utilities should use standard QF methodologies for systems below 3 MW, consistent with QF guidelines. Renewable NW also states there is uncertainty over PacifiCorp's PDDRR method in docket UM 1802 where Staff has proposed an alternative approach to calculate the non-standard renewable avoided cost prices. Renewable NW prefers a methodology that is similar to avoided costs but not directly tied to QF methodologies because of the regulatory uncertainty from avoided cost litigation, and Staff generally agrees with this comment.

TASC and CUB contend the utilities should use hourly data if available, noting that monthly, weekly, or even daily averages will underestimate the value of solar generation. E3 also noted a potential increase in energy values using hourly data, but that at higher penetrations energy values could decrease. PacifiCorp responds that this will be burdensome for little precision and will require confidential information to be protected in compliance dockets.

b. Resolution

We modify the straw proposal to require more granular energy values to advance the idea that RVOS values should have a price shape. We direct the utilities to use a 12 x 24 block for energy prices, and to include a detailed explanation of how they created the 12 x 24 block. Our expectation is that, for each of the 12 months in a year, utilities would develop a typical day shape of prices across 24 hours from the same pricing source used to develop their average monthly or annual on and off-peak standard QF energy values. We require this more granular approach because we agree with the parties that a daily shape is important for solar compensation. We intend to move toward accuracy and granularity over time as penetration increases, and believe that a 12 x 24 block is a reasonable compromise that achieves a level of detail while addressing the utilities' concerns over confidentiality and administrative burden.

We acknowledge the concerns about tying RVOS energy values to litigated QF avoided cost filings. It is too early to decide whether QF avoided costs and RVOS should be synched up in their updates.

Regarding PDDRR and ICIRP, we allow PacifiCorp and Idaho Power the option to provide an additional 12 x 24 block created from their system-dispatch models as a reference point for energy and capacity. PacifiCorp and Idaho Power would need to provide model assumptions such as the solar resource's location, performance, size, and provide access to models for party review. We will balance accuracy, transparency and accessibility to parties as we review these values and determine the best methodology for RVOS moving forward.

We remove the straw proposal's "next step" of a workshop or technical conference to examine hourly energy values in the future. Staff may suggest an appropriate time for workshops as we move forward. In addition, we will be able to address next steps for increasing granularity and accuracy of energy values in future RVOS orders.

2. *Hydro Conditions*

To calculate avoided energy, the straw proposal states that utilities must examine and evaluate different schemes for weighting hydro years and report the results of their examination.

a. *Party Testimony*

E3 explains that it is necessary to model a range of hydro conditions because low hydro conditions may increase energy prices much more than high hydro conditions decrease them (a concept known as the flaw of averages). CUB agrees and states the Commission has long recognized that the cost of bad water years is greater than the benefit of good water years.

Generally, the utilities state that modeling a range of conditions is cumbersome and ask to use their current approach to evaluating impacts of hydro variability. PGE and Idaho Power ask to use their established IRP hydro value, which is a median. PacifiCorp supports using a mean, reasoning that variations over time will gravitate to a mean.

b. *Resolution*

We agree with E3 and CUB that the energy data input for future energy prices should reflect a distribution of potential hydro conditions. Because the energy element is so important to the RVOS calculation, we modify the straw proposal and ask 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. In response testimony in Phase II, we ask the parties to specifically respond to the utilities' analyses so that we will have a full record to evaluate.

B. Avoided Generation Capacity

1. *Value During Resource Sufficiency*

The straw proposal directs the utilities to determine the marginal avoided costs of capacity consistent with QF avoided cost guidelines, with a market energy price during resource sufficient years and a proxy price scaled for solar's contribution to peak in resource deficient years.

a. *Party Testimony*

At the January hearing, E3 recommended that avoided O&M costs be assigned as a generation capacity value during the sufficiency period. PacifiCorp disagrees, stating that even when dispatchable resources are used less, the fixed costs of maintaining those resources is unchanged.

TASC states that the methodology should be flexible enough so that solar paired with dispatchable storage has a higher value. PGE, PacifiCorp, and Staff believe that the RVOS model is flexible and should not be broadened to consider hypothetical future solar plus storage systems. TASC also raises issues with the assumptions in the utilities' IRP preferred case, stating that a number of coal plants may retire earlier than the preferred case assumptions, which would change the resource balance year from 2028 to 2021.

Idaho Power and PacifiCorp seek some clarification that their avoided cost methods for non-standard QF avoided costs are acceptable. Idaho Power states that when it is resource sufficient, the capacity value should be zero. Idaho Power objects to using standard avoided cost methodology with its two-step process for resource deficiency (a proxy resource, scaled for solar's contribution to peak). Idaho Power prefers to omit the proxy resource and just use its IRP sufficiency/deficiency demarcation and the UM 1719 methodology for contribution to peak.

PacifiCorp proposes to use the PDDRR methodology from its non-standard avoided costs. During the sufficiency period the value is deferral of front office transactions. During the deficiency period, PDDRR should account for the cost of additional forecasted resources added.

b. Resolution

We retain the straw proposal approach whereby all utilities will provide capacity value and timing (deficiency date) in line with their current approved standard nonrenewable QF avoided cost capacity value. Adopting our current QF practice is most efficient for the first version of RVOS, and appropriately values the capacity acquisition that is being avoided by the utility due to solar PV.

As noted for the avoided energy element, to the extent that PacifiCorp and Idaho Power would like to provide energy and capacity values through their non-standard QF modeling approaches, they are permitted to produce capacity values based on their system dispatch models in addition to the standard nonrenewable QF approach. Again, we will balance accuracy, transparency and accessibility in reviewing these alternative approaches.

For clarity and as a reference to the parties, we summarize our current standard nonrenewable QF capacity calculation. During resource sufficient years, the utility uses forward market prices to calculate avoided cost price.[3] We have explained that utilities

[3] *In the Matter of Public Utility Commission of Oregon, Investigation Relating to Electric Utility Purchases from Qualifying Facilities,* Docket No. UM 1610, Order No. 16-174 at 2, 15-19 (May 13, 2016) (Discussed

use market transactions to meet demand when the utility is not in the process of acquiring resources. We have found that this approach embeds the value of incremental QF capacity in the total market-based avoided cost rate.

During a resource deficient period, a utility multiplies the contribution to peak of a QF's resource type by the capacity cost of the utility's avoided proxy resource. For example, if the utility's acknowledged IRP states that solar PV has a 25 percent contribution to peak, the capacity value would be 25 percent of the capacity cost of the avoided proxy resource.[4]

For next steps on valuing generation capacity during resource sufficiency, we direct Staff to convene a workshop at a future time it chooses. We ask Staff and the parties to explore options for valuing capacity additions incrementally during resource sufficiency. The issues to be explored at the workshop include: (1) allowing the full capacity value up to a reasonable number of years before the deficiency year (*e.g.*, three or four years) as recognition that it takes several years to ramp up infrastructure to avoid a major resource; (2) using the short run marginal cost of fixed operations and maintenance (O&M) as a proxy value as suggested by E3; and (3) other ideas arising from related Commission dockets or those raised by the parties.

2. *Resource-Balance Year*

Parties have discussed whether solar PV should be included in the utilities' load forecast, or whether it would cause the sufficiency period to be continuously extended. The straw proposal states that during Phase II, the utilities shall run sensitivity analyses to determine what level of solar PV penetration has a material effect on the load resource balance.

a. Party Testimony

Renewable NW, TASC, and Staff support removing solar PV from the utilities' load forecast and support the sensitivity analyses suggested by the straw proposal. PacifiCorp disagrees, stating that incremental solar resources that are being paid for capacity should be included in PacifiCorp's planning, either as an offset to load or as a resource.

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at Issue 6, making no change and affirming our previous position that market-based prices during resource sufficiency periods adequately compensate QFs for power produced.).

[4] *Id.* at 9. *See also In the Matter of Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity*, Docket No. UM 1719, Order No. 16-326 (Aug 26, 2016) (adopting an all-party stipulation providing that the utilities will either use the Effective Load Carrying Capability (ELCC) method or a Capacity Factor (CF) approximation method to estimate the capacity contributions from renewable generators.).

b. Resolution

We modify the straw proposal and require the utilities to remove incremental distributed solar PV from the load forecast for their initial RVOS filings. In calculating the generation capacity deferral value, utilities should use their last acknowledged IRP resource-balance year, and then remove new incremental expected distributed solar PV from that forecast, and then if applicable, provide an adjusted deficiency date. We are convinced that this adjustment can be accomplished in the initial RVOS filings, and find no need to wait for a later phase of RVOS. It is our understanding that, if a forecast for incremental distributed solar PV is included in utility load forecasts, then the utilities can adjust their forecast to exclude this generation. We accept E3's reasoning that if solar resources are included in the load forecast, the resource balance year will be pushed further into the future which will in turn decrease the generation capacity element of the RVOS.

C. Avoided Transmission and Distribution Capacity

1. Valuation

The straw proposal asks the utilities to propose in Phase II a system-wide average of avoided T&D attributable to incremental solar. The straw proposal specifies that the avoided T&D should be for growth-related investments.

a. Party Testimony

E3 disagrees with the straw proposal, stating that avoided or deferred T&D should be for all T&D upgrades, which will mostly be tied to load growth (*i.e.,* deferral of a large transformer) but it should not be limited to this circumstance.

While ultimately PacifiCorp supports an Oregon-wide proxy for administrative ease, the utilities all stated that T&D should only be non-zero if there are actual location-specific T&D investments that can be deferred. TASC and Staff disagree with this position, stating that the entire fleet of distributed resources contributes collectively to deferring potential upgrades. Staff states that a single solar PV array may not defer a T&D investment, but several systems on the same feeder could contribute to the deferral. TASC is specifically concerned that our RVOS will not account for the value of distributed storage, and explains that the avoided value could be significantly higher for PV paired with storage.

b. Resolution

We retain the straw proposal's approach that utilities' initial RVOS compliance filings should use 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. We agree with E3's last round of testimony that clarified that avoided costs need not be specifically limited to growth related-investments. We have long required utilities to estimate avoidable T&D costs by referencing their most recent studies used to set rates (Marginal Cost of Service Study) and the utilities may continue to use those studies for the first version of RVOS.[5]

2. *Next Steps*

Going forward, the straw proposal asks the parties to convene a workshop to examine ways to generate location-specific T&D estimates.

a. Party Testimony

E3 states that the utilities need to compile their capital expenditure plans in each geographic area and then assess what may be deferred or avoided due to solar in those areas. E3 observes that a more location-specific RVOS will encourage optimal placement of new systems. Renewable NW believes that locational values could be determined earlier than anticipated because more granular data may already be available, such as PacifiCorp's distributed energy resource template in its smart grid report. PacifiCorp states this tool may be helpful but was not designed for RVOS. ODOE agrees with the need to strive for data granularity for this element.

b. Resolution

We modify the straw proposal by removing the workshop requirement and instead directing the utilities to provide additional information on this element in their Phase II initial filings. Specifically, the utilities are to explain in their RVOS filings what information and methodologies they currently have for location specific distribution planning and how those could be used or adapted in the near term to advance the granularity of this element for the next iteration of RVOS. E3's earlier testimony noted that Oregon utilities may benefit from studying how the value of solar and other distributed energy resources differ between geographic locations based on the specific transmission and distribution system characteristics in that area, and we ask the utilities to address what they can do in the near term to help this element evolve to provide a more location-specific value for their systems.

D. Avoided Line Losses

The straw proposal asks the utilities to propose in Phase II estimates of incremental avoided marginal line losses reflecting the hours solar PV is generating electricity.

[5] *In The Matter of an Investigation into the Calculation and Use of Conservation Cost-effectiveness Levels*, Docket No. UM 551, Order No. 94-590 (Apr 6, 1994) (Explaining the avoided cost methodology used to quantify the utility benefits of energy efficiency. Utilities translate this methodology into their IRP processes when evaluating energy efficiency against other resource options in IRPs.).

1. Party Testimony

E3 explains that marginal losses will be greater than average losses because line losses increase non-linearly with system load. PacifiCorp disagrees, stating that marginal line losses can be either higher or lower than average depending on system conditions. PacifiCorp also states that when the solar resource exceeds the behind-the-meter load on that meter, there will be incremental losses on the distribution system.

Renewable NW and Staff note that our definition should be clarified. Staff states that an hourly average value for different parts of the system may be the best approach.

E3 explains the benefit of hourly data is that it captures the alignment of PV with changes in loads which affect line losses. PacifiCorp states that an hourly analysis would have to capture its system conditions. TASC states that if hourly values are not available, the most granular time step available should be used to capture the coincidence of solar generation with highest load hours, when losses are highest. ODOE also supports granular data for this element.

2. Resolution

We ask the utilities to develop hourly averages of line losses by month for the daytime hours when load on the system is higher, losses are greater, and solar is generating. We expect the utilities' values to recognize and reflect that there are seasonal and daily variations in line loss impacts with higher temperatures and higher loads having higher losses. We do not expect a true hourly value to this element, but ask the utilities to provide the most granular value they reasonably can inclusive of daytime and seasonal variation, with an explanation of the value in their filings.

E. Administration

The straw proposal asks the utilities to propose in Phase II estimates of direct, increased utility costs of administering solar PV programs, with justification of their method and value. Renewable NW asks us to clarify that this excludes the cost of interconnection paid by the interconnecting solar generator.

We modify the straw proposal to remove "interconnection" because we agree with Renewable NW that there should be no overlap with the interconnection costs that large generators bear separately. E3 explains the Administration element is only intended to capture costs that are both incremental to what the utility incurs for any other customer account and incremental to any portion of the cost paid by the interconnecting solar generator.

F. Market Price Response

The straw proposal explains market price response as lower wholesale energy market prices caused by increased solar PV production. The straw proposal suggests that, in tandem with Phase II, Staff shall convene a workshop to examine how to estimate this value, and then utilities shall develop estimates and report preliminary results in Phase II.

1. Party Testimony

The utilities ask for clarification that this value should initially be set at zero, and not included in the utility's compliance filings. Renewable NW also asks for clarification as to whether this element will be in Phase II or used a later date. Renewable NW suggests we look at a report from Iowa for additional information on this element.

PGE, PacifiCorp, and Idaho Power generally support a workshop/technical conference, but explain that results may be modest. They caution that it is unclear how to quantify a Mid-C price impact, the value may be zero, and that the parties may end up agreeing there is not enough data to develop a calculation methodology. PacifiCorp asks that instead of specifying that the utilities will calculate preliminary values after the workshop, we should simply direct that workshops convene and then decide on next steps based on the outcome of the workshops. E3 states that it has developed a method for estimating the impact of increasing wind energy at Mid-C, and this could be a reasonable proxy method for increasing solar. E3 states that this element of RVOS will be a very small portion of the total RVOS and significant resources should not be expended to more accurately quantity this element relative to a proxy method (similar to Hedge Value, discussed below).

2. Resolution

We modify the straw proposal so that instead of convening workshops on this element, we direct 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. We agree with several of the parties that when data is not available at the desired level of granularity, the utilities should not assume the value is zero, unless there is firm evidence that a value does not exist or that solar installations cannot contribute to it. Because we are hoping to have final RVOS values in less than one year, we believe it is most efficient and reasonable to use E3's model on increasing wind energy at Mid-C as a proxy for valuing market price response of incremental customer-owned solar PV.

G. Avoided Hedge Value

The straw proposal asks Staff to convene a workshop and recommend a methodology for calculating avoided hedge value, and then the utilities are to produce a preliminary value in Phase II using Staff's methodology. The straw proposal also asks the utilities to consider their proposed value and the interaction of hedging strategies and customer attitudes about price stability to justify the utility's method.

1. Party Testimony

The utilities generally ask that this value be zero for Phase II, and other parties generally support a positive value. E3 explains this element is small relative to the aggregate RVOS, and believes a proxy value equal to 5 percent of energy is sufficient, and expending additional resources to more accurately quantify this value would cost ratepayers more than the benefit of increased accuracy. PacifiCorp opposes an arbitrary proxy value. PGE and PacifiCorp recommend proceeding with the workshop, though they believe the hedge value is likely zero at current PV levels. Idaho Power maintains that the value should always be zero and does not support a workshop because the company follows its Idaho PUC-approved hedging strategy which doesn't vary for additional PV.

Renewable NW and CUB ask us to clarify that the workshop will actually inform Phase II. Renewable NW suggests we look at a City of Austin report for more information on natural gas price uncertainty. CUB does not think the value should be zero because PV provides a long-term physical hedge against changes in fuel prices, and PGE's IRP shows that the company does physical gas hedging. E3, Staff, and CUB state that elements should not be valued at zero when there is uncertainty, instead a proxy should be used.

2. Resolution

We modify the straw proposal and adopt E3's suggestion for a proxy value of 5 percent of avoided energy. Throughout this proceeding E3 has used this proxy value in its model runs. For this first version of RVOS we are convinced by E3's reasoning that the effort required to calculate hedge value at this time would outweigh its value to solar projects or to ratepayers. We decline the suggestion for a zero value because, similar to Market Price Response, we are persuaded that there is some value to this element.

H. Avoided Environmental Compliance

The straw proposal directs the parties to propose a value in Phase II based on carbon regulation assumptions from their IRP.

1. Party Testimony

PacifiCorp and Idaho Power both disagree with this element stating that future environmental compliance scenarios are appropriate for resource planning but are too speculative to be included in RVOS pricing of long-term contracts. PacifiCorp recommends that RVOS be updated regularly to capture policy changes. Idaho Power agrees with using the carbon regulation assumptions from its IRP, stating that this value should be zero.

TASC disagrees with PacifiCorp, stating that many procurement decisions are made based on IRP assumptions about future conditions. Staff also believes the IRP assumptions are reasonable because they are the company's best estimate of the costs of regulatory compliance in the future.

2. Resolution

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

I. Avoided RPS Compliance

The straw proposal directs the utilities to propose this value in Phase II, using a methodology that considers the reduction in load and the levelized cost of the marginal renewable resource installed in the year when utilities need to act to comply with RPS requirements.

1. Party Testimony

PacifiCorp points out that the RPS definition in the straw proposal is the avoided cost of purchasing RECs. PacifiCorp asks us to expand the methodology to include the definition, so it would provide two options for the calculation: either the avoided cost of purchasing RECs or the cost of a marginal renewable resource.

E3 states that it has proposed a straightforward method that is equal to the RPS premium multiplied by the RPS percentage. The RPS premium is the cost of a RPS contract minus the market value of the energy and capacity that the resource provides. The RPS premium should be calculated based on the expected price of RECs when the utility needs to procure additional RPS energy. The RPS premium is multiplied by the RPS percentage to link the reduction in load (due to solar PV) to the reduction in the utility's RPS obligation.

2. Resolution

We direct the utilities to assign a zero value as a placeholder for this element in their initial RVOS filings. However, we will revisit the proper inputs for this element, and will endeavor to assign a methodology before the end of Phase II. At this time, we find that the value or cost of avoided RPS compliance overlaps with several other pending dockets.

J. Integration and Ancillary Services

The straw proposal directs the utilities to propose this value in Phase II, estimating costs based on IRP wind and solar integration studies.

1. Party Testimony

E3 explains this element has three different components: (1) integration costs, (2) avoided ancillary services, and (3) providing ancillary services. For integration costs, E3 states that because solar increases variability on the system, the utility must hold additional reserves. E3 suggests a one percent cost based on what other utilities have done. Renewable NW states that of the three types of reserves (contingency reserves, load-following reserves, and regulation reserves) the contingency reserves will not be affected by PV because they are needed for outages, but the load following reserves may need to increase. Renewable NW asks that RVOS be updated as PV forecast accuracy improves.

E3 explains there are also avoided ancillary service requirements due to reduced load. E3 explains that the model currently calculates the sum of integration and ancillary services reduction as one percent of avoided energy value (a very small fraction of total RVOS). TASC supports E3's general proxy approach to value the portion of energy costs typically spent on ancillary services, as it has done in other states. PacifiCorp disagrees with the one percent proxy, stating that its IRP has detailed integration studies with cost analysis.

Regarding ancillary services benefits, generators may provide regulation up, regulation down, or load following services. The straw proposal states that this should be zero for now, and at a later date, Staff shall convene a workshop to evaluate incremental benefits from smart inverters. E3 states that ancillary services benefits should not be included in RVOS. E3 explains that typically a generator must curtail energy on a regular basis in order to ramp on demand for ancillary services, and this requires advanced infrastructure beyond the standard mass market installation. TASC states that ancillary services benefits should not be zero because SolarCity's storage can proactively provide services.

2. Resolution

We modify this element so that it includes only integration costs, and retain the straw proposal methodology whereby the utilities will use inputs for integration costs based on acknowledged integration studies. We remove "Ancillary Services" from this element and move it to the last element (formerly Security, Reliability, and Resiliency) which we rename "grid services," and discuss further below.

We note that TASC argued for a few elements to include the value of PV systems paired with storage, *i.e.*, generation capacity, T&D capacity, and this element, ancillary services. We agree with E3's explanation that very few solar systems are currently installed with storage. However, E3 explained that RVOS could be modified to apply to PV with storage. We welcome TASC's participation as we are trying to increase our understanding of the value of storage on the system in the energy storage docket. We invite TASC to file a proposal on how we could value solar paired with storage in this docket, including descriptions of how energy storage impacts other elements and how these impacts could be incorporated into a future version of RVOS. If TASC chooses to file a proposal, it should be submitted in this docket so that it may be considered as we evaluate RVOS issues in the first half of 2018.

K. Security, Reliability, and Resiliency[6]/Grid Services

The straw proposal states this element should be zero for now, and that Staff should conduct a workshop to examine methodologies to quantify this element.

1. Party Testimony

The parties generally agree with the straw proposal's approach, with some caveats. E3 explains that solar generators with advanced and uncommon infrastructure such as microgrids are capable of islanding during an outage event, but this benefit accrues to the owner and not to general utility ratepayers. E3 recommends that security and reliability benefits should not be valued in RVOS. E3 comments that "reserve" benefits are already accounted for in the ancillary services element. PacifiCorp and Idaho Power make similar observations, and ultimately support the zero value, though they do not oppose a workshop going forward.

ODOE, CUB, and Staff support this element so that the benefits are captured as technology advances. Renewable NW asks when the smart inverter rulemaking will begin, because it could trigger a non-zero value for this element. E3 observes that a separate RVOS should be calculated for customers with smart inverters that benefit general utility ratepayers (such as controlling output to provide ancillary services), but that no value is needed for smart inverters that mitigate incremental costs caused by the PV. Staff explains that a smart inverter rulemaking may not be necessary because the IEEE standards will be updated imminently (in response to California's Rule 21) to require that all inverters have smart capabilities.

[6] Renewable NW notes that the straw proposal contains a typo stating "Security, Reliability, and Reserves" and that it should read "Security, Reliability, and Resiliency".

2. *Resolution*

This element is to be renamed as "grid services," and we retain the straw proposal approach that this element will be valued at zero for the utilities' Phase II filings. We recognize that, in the future, there may be benefits from both advanced, uncommon applications and from utilities' increasing ability to capture the benefits of mass-market smart inverters that will become standard upon adoption of new IEEE standards. While this first version of RVOS is meant to be generally applicable to a solar system installed by a retail, mass market customer today, we have not prejudged any applications, and we retain this element to capture the potential incremental system benefits from solar in the future.

In future versions of RVOS, those benefits may come from advanced and uncommon infrastructure, such as solar that can provide ancillary services (regulation or load following) or solar with microgrid or islanding capability. E3 suggested that these additional services be calculated separately and applicable only to those installations that provide them.

Benefits in future versions of RVOS may also come from utilities capturing value from standard smart inverters. We invite Renewable NW or other parties to make a proposal for valuing enabled smart inverters based on best practices or other utility experiences, and how the utilities could capture this value. If Renewable NW chooses to file a proposal, it should be submitted in this docket so it may be considered as we evaluate RVOS issues in the first half of 2018.

L. The Levelization Period and Utility-Scale Alternative

The straw proposal contains two general issues that are listed as bullet points at the end. These are the levelization period, and the alternative utility-scale estimate of RVOS.

1. *Levelization Period and Implementation Questions*

The straw proposal states that RVOS will be a 25 year analysis updated every two years or upon petition.

a. *Party Comments*

E3 recommends a 30 year levelized RVOS that is recalculated annually. 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. E3 believes 30 years is a reasonable expectation for the lifetime of a solar installation. PacifiCorp states that 25 years is too long, given the uncertainty over which programs will use RVOS. PacifiCorp recommends a shorter timeframe with more frequent updates.

The utilities and Renewable NW also commented on the application of RVOS. Idaho Power comments that the RVOS model will produce a 25 year marginal, levelized value for a generic small-scale solar resource installed in 2016, and because this is a limited purpose, RVOS should be reevaluated before it is applied in other contexts such as utility scale or community solar. PacifiCorp adds that it's unclear how RVOS will set the bill credit rate for community solar. Idaho Power is also concerned about using RVOS for net metering, because RVOS doesn't reflect embedded costs of customer rates. Staff believes these concerns are premature. Renewable NW cautions against prejudging any application of RVOS, and explains that SB 1547 provides the subscriber shall be credited in a manner that reflects RVOS, not necessarily by RVOS directly. Renewable NW also notes that statements about applying RVOS to net metering have been Staff's statements, not the Commission's. Renewable NW states that RVOS for rooftop solar will need to be determined in UM 1716 Investigation 2, which will explore the extent of cost-shifting, if any, between participating and non-participating customers.

b. Resolution

The utilities should populate the E3 workbooks with the above listed elements for 25 years beginning in 2018, and provide all supporting assumptions and data. Each utility will calculate RVOS using a combined cycle gas plant as the avoided resource with the following elements: Energy, Capacity, T&D, Line Losses, Administration, Integration, Hedge Value, and Market Price Response.

We have not determined how RVOS will apply to community solar (nor any other application), but see value in having parties begin implementation discussions within this phase and not wait until the end of Phase II. We direct Staff to hold an implementation workshop to identify issues related to application of RVOS to community solar and report back to us in a public meeting before April 2018. Similarly, we will decide later, based on application, whether RVOS should be updated annually or every two years.

2. Utility Scale Alternative

The straw proposal states that the utilities shall produce an alternative estimate of RVOS using a utility scale solar resource as a proxy resource. E3 proposed this at the January hearing, stating that RVOS should be the lower of the conventional proxy or the utility solar proxy. The straw proposal states that, to calculate this alterative, a utility solar proxy resource should replace most RVOS elements except for transmission and distribution capacity, line losses, and administration (these are benefits/costs that rooftop solar provides that utility scale solar does not). E3 testified that the utility scale proxy also adds in additional RPS compliance value because of RECs delivered. The straw proposal specifies that the utilities are to explain their process for valuing a utility scale solar proxy and any values from their IRPs.

a. Party Testimony

PacifiCorp suggests that utility scale solar resource costs can be used as a cap on the RVOS value. Staff and Renewable NW caution that the utility scale solar resource value should be used as a reference only. CUB commented that the utility scale solar proxy should not be a Phase II issue but part of the IRP. TASC states that utility scale solar is an inappropriate proxy for distributed solar and it will not capture the value of systems with production profiles that differ from utility scale solar, such as solar paired with storage. TASC and Renewable NW also explain a recent Arizona decision that replaced net metering with a utility scale solar proxy. TASC states that the move away from net metering in Arizona only occurred after robust levels of distributed and grid scale solar. TASC also states that Arizona uses an average of utility-scale PPAs over a prior five-year period for projects that are actually in service.

b. Resolution

As a reference point only, the utilities should provide a separate E3 workbook with a RVOS assuming a utility scale solar proxy to replace all elements but T&D capacity, administration, and line losses. The utility scale proxy is not a cap on RVOS, it is only a reference point to advance understanding of evaluation methods as we work through Phase II. The utilities should explain their utility scale proxy and how it relates to their IRPs.

M. Procedure and Timing

1. Party Testimony

The utilities suggest that the general policy workshops remain in docket UM 1716, while the Phase II compliance filings proceed in new utility-specific contested case dockets. In general the utilities believe they have sufficient guidance from the straw proposal to calculate RVOS values and believe it is more efficient to begin Phase II with a formal filing, followed by party testimony. PacifiCorp prefers individual compliance filing dockets because each utility's filing will be different and contain confidential information.

Staff proposes a modified path that begins with an informal process as the utilities develop RVOS values and Staff conducts workshops on market price response and hedge value. Staff and the utilities disagree on what would happen after the workshops if they did not agree on a calculation methodology for those elements.

ODOE, Renewable NW, and CUB support Staff's schedule because it is more iterative and they believe it has more opportunity for party input. TASC prefers a more formal process for party input with filed testimony over the workshops.

2. *Resolution*

To initiate Phase II, the utilities should make formal compliance filings in new dockets. This is more efficient as we work towards establishing this first RVOS value. We hope to proceed along the following schedule:

PROPOSED SCHEDULE			
Phase II RVOS Filings	**Date**	**Related Workshops**	**Date**
Utilities' Individual RVOS Filings in new dockets	November 30, 2017		
Staff/Intervenor responsive testimony and company reply testimony on RVOS filings	January and February 2018		
		Staff-led workshops in UM 1716 on implementation issues related to community solar	January 2018
Potential Hearing on Utility-Specific RVOS filings	March 2018	Staff to present results of workshops at a Public Meeting	April 2018
Briefs on Utility Specific-RVOS filings	April 2018		
Commission Order on Utility-Specific RVOS filings, followed by utility compliance filings	July 2018		

III. ORDER

IT IS ORDERED that

1. Portland General Electric Company; PacifiCorp, dba Pacific Power; and Idaho Power Company make initial RVOS filings in new utility-specific dockets by November 30, 2017, and include initial testimony with workpapers explaining their calculations.

2. The Alliance for Solar Choice, Renewable Northwest or other parties may submit proposals in this docket on valuing solar paired with storage and smart inverter benefits.

3. Commission Staff is to report back to us at a Public Meeting by April 2018 on implementation issues for applying RVOS to community solar.

Made, entered, and effective SEP 15 2017.

Lisa D. Hardie
Chair

Stephen M. Bloom
Commissioner

Megan W. Decker
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

RVOS Proposal

Element	Definition	Inputs from the Utilities	Next Steps
1. Energy	The marginal avoided cost of procuring or producing energy, including fuel, O&M, pipeline costs and all other variable costs.	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.	The utilities shall propose this value in Phase II.
2. Generation Capacity	The marginal avoided cost of building and maintaining the lowest net cost generation capacity resource.	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.	The utilities shall produce this value in Phase II. At a later date of Staff's choosing, Staff is to convene a workshop to explore options for valuing capacity additions incrementally.
3. Transmission and Distribution Capacity	Avoided or deferred costs of expanding, replacing, or upgrading transmission and distribution (T&D) infrastructure.	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.	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.

Element	Definition	Inputs from the Utilities	Next Steps
4. Line Losses	Avoided marginal electricity losses.	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.	The utilities shall propose this value in Phase II.
5. Administration	Increased utility costs of administering solar PV programs.	Utilities shall develop estimates of the direct, incremental costs of administering solar PV programs including staff, software, incremental distribution investments, and other utility costs.	The utilities shall propose this value in Phase II. Utilities shall provide justification for their method and value.
6. Integration	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.	Utilities will make estimates of integration costs based on acknowledged integration studies.	The utilities shall propose this value in Phase II.
7. Market Price Response	The change in utility costs due to lower wholesale energy market prices caused by increased solar PV production.	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.	Utilities shall include the proxy value in their Phase II filings.
8. Hedge Value	Avoided cost of utility hedging activities, *i.e.*, transactions intended solely to provide a more stable retail rate over time.	Utilities are to assign a proxy value of 5 percent of energy.	Utilities shall include the proxy value in their Phase II filings.

Element	Definition	Inputs from the Utilities	Next Steps
9. Environmental Compliance	Avoided cost of complying with existing and anticipated environmental standards.	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.	The utilities shall calculate this value for informational purposes and include it in their Phase II filings.
10. RPS Compliance	To be determined.	The utilities shall use a value of zero in their initial Phase II filings.	This element is to be further considered in Phase II.
11. Grid Services	The potential benefits of solar PV in advanced, uncommon applications and from utilities' increasing ability to capture the benefits of mass-market smart inverters.	The utilities shall use a value of zero for this element.	To be evaluated based on future proposals.