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April 20, 2018

VIA ELECTRONIC MAIL

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

Re: Docket UM 1911: Idaho Power Resource Value of Solar

Attention Filing Center:

Attached for filing in the above-captioned docket is Idaho Power Company's Reply Testimony of Rick Haener (Idaho Power/200) and workpapers.

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Legal Assistant

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

DOCKET NO. UM 1911

IN THE MATTER OF IDAHO POWER COMPANY'S COMPLIANCE FILING REGARDING THE RESOURCE VALUE OF SOLAR PURSUANT TO ORDER NO. 17-357.	))))))

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

RICK HAENER

April 20, 2018

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

A. My name is Rick Haener and my business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Power Supply Planning Leader.

Q. Are you the same Rick Haener that previously provided Direct Testimony in this docket?

A. Yes, I am.

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

A. The purpose of my Reply Testimony is to present Idaho Power's response to opening testimony filed on March 16, 2018, by the Public Utility Commission of Oregon ("Commission") Staff ("Staff"), Renewable Northwest ("RNW"), Oregon Department of Energy ("ODOE"), Oregon Solar Energy Industries Association ("OSEIA"), and the Oregon Citizens' Utility Board ("CUB").

Q. How is your testimony organized?

A. I have organized my Reply Testimony so that, for each of the individual elements to be used in the initial Resource Value of Solar ("RVOS") calculation: (1) I provide the methodology used to develop each individual RVOS element as directed by Order No. 17-357; (2) I provide a brief description of how the methodology used by Idaho Power complied with the Commission's directive; (3) I address Staff's and other intervening parties' comments on Idaho Power's approach to the RVOS elements; and (4) I provide Idaho Power's reply to intervenor comments.

Q. Please describe Order No. 17-357, which modified and adopted the straw proposal for utility RVOS calculations.

A. In Order No. 17-357, the Commission largely adopted the RVOS methodology proposed by Energy and Environmental Economics, Inc. ("E3") to produce a 25-year marginal, levelized value for a generic, small-scale solar resource installed in 2017.

Order No. 17-357 at 1. The Order adopts 11 specific elements to be included in the utilities' RVOS calculations. Four elements make up the majority of the calculation: energy, generation capacity, transmission and distribution ("T&D") capacity, and line losses. As noted by the Commission, the values of these four elements would largely come from the utilities' existing avoided cost prices or existing cost studies, with additional granularity to properly value the shape of solar production. Order No. 17-357 at 2.

Two elements, administration and integration, are specific costs to the utility. The values for these two elements would come from existing utility studies. The next two elements, hedge value and market price response, would use assigned proxy values for the initial RVOS Phase II filings. The next element, environmental compliance, would be treated as an informational placeholder in the initial RVOS Phase II filings. The last two elements, renewable portfolio standard ("RPS") compliance and grid services, would be valued at zero in the utilities' initial RVOS Phase II filings.

Q. Based on the prescribed methodology established by the Commission, what initial value did Idaho Power determine for the RVOS?

A. Idaho Power's initial RVOS calculation, filed in opening testimony, resulted in a levelized net RVOS of $1.61 per megawatt-hour ("MWh") for a standard size project, which included the costs of metering communication fees required of the Oregon Solar Photovoltaic Pilot Program ("Oregon PV Pilot") as part of the administrative cost category. If those costs are otherwise recovered and removed from the administration component of the RVOS calculation, the result is a net levelized RVOS of $31.18 per MWh.[1]

[1] Idaho Power/100, Haener/16

Q. Did Idaho Power update its RVOS value based on recommendations made in the opening testimony of Staff and intervenors?

A. Yes. Idaho Power adopted some of the recommendations suggested by Staff and intervenors in opening testimony, which will be described in detail in the following sections of my testimony. Of note, Idaho Power's 2017 Integrated Resource Plan ("IRP") was acknowledged by the Commission on April 10, 2018. Where applicable, Idaho Power updated its RVOS calculation to replace 2015 IRP-based assumptions and inputs with 2017 IRP assumptions and inputs. Based on the updates made by Idaho Power, the Company calculated a revised levelized net RVOS of negative $5.68 per MWh. The table below presents the quantification of each element of the RVOS calculation and the levelized net RVOS value, both as initially calculated and the revised RVOS calculation being presented herein. I have also included an RVOS determination assuming the removal of communication costs from the administration component, as I describe later in my testimony.

Element	**Initial Value Standard Size Project** ($/MWh Real Levelized)	**Revised Value Standard Size Project** ($/MWh Real Levelized)	**Revised Value Standard Size Project Reduced Administration Cost** ($/MWh Real Levelized)
1. Energy	29.74	25.30	25.30
2. Generation Capacity	15.30	13.50	13.50
3. T&D Capacity	0.87	0.54	0.54
4. Line Losses	2.54	2.05	2.05
5. Administration	(47.77)	(47.77)	(18.20)
6. Integration	(0.56)	(0.56)	(0.56)
7. Market Price Response	0.00	0.00	0.00
8. Hedge Value	1.49	1.26	1.26
9. Environmental Compliance	0.00	0.00	0.00
10. RPS Compliance	0.00	0.00	0.00
11. Grid Services	0.00	0.00	0.00
Net Levelized RVOS	**1.61**	**(5.68)**	**23.89**

Idaho Power is submitting its revised RVOS workbook as part of the Company's workpapers with this testimony.

I. RVOS ELEMENTS

Element No. 1 – Energy

Q. What was the Commission's direction for developing the energy component of the RVOS calculation?

A. For the energy component, the Commission directed utilities to use a 12-month x 24-hour block to develop energy prices. The Commission stated that they modified the straw proposal to require more granular energy values to advance the idea that RVOS values should have a price shape. Their expectation was 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 standard qualifying facility ("QF") avoided cost pricing.

Q. What did Idaho Power provide for the energy component of the Company's initial RVOS determination?

A. In developing the energy component of the RVOS determination, Idaho Power recognized the Commission's desire to use more granular values when available to achieve the best estimate of RVOS. With the availability of hourly solar energy shapes collected from Idaho Power's participants in the Oregon PV Pilot, Oregon Schedule 88, the Company believed it was more responsive to the Commission's goal of providing granularity by using the actual hourly capacity output to develop energy shapes for the RVOS, rather than a 12-month x 24-hour profile. These hourly energy shapes were multiplied by the Company's published annual standard avoided cost of solar energy, Schedule 85, to the develop hourly energy prices.

Q. Were comments provided by Staff and other intervening parties which differed from the Company's approach?

A. Yes. Staff stated that Idaho Power's energy prices applied a shape factor of one, resulting in a flat shape. Staff suggested that Idaho Power should apply a 24-hour price shape. RNW stated that Idaho Power's decision to model a new system installed in 2017 as a participant of the Oregon PV Pilot was unreasonable as the program is no longer open to new participants; however, RNW made no recommendation on how to value the energy element of RVOS. And OSEIA recommends that Idaho Power shape its energy prices using PacifiCorp's approach, which is based on a recent hourly profile of prices in the Energy Imbalance Market (EIM).

Q. What is Idaho Power's response to the parties suggested modifications for the calculation of the energy value?

A. The Company believes that the actual hourly capacity output collected from Idaho Power's participants in the Oregon PV Pilot accurately reflects the energy shapes to be used for the RVOS; however, the Company agrees with Staff's recommendation to provide a 24-hour price shape rather than just the flat avoided cost rate to be applied to the hourly capacity output to better reflect the value provided by the resource at different times of the day/month/year. For the updated RVOS workbook submitted with my testimony, Idaho Power used actual hourly Mid-Columbia ("Mid-C") market prices for 2017 to develop an index to shape the Schedule 85 published standard avoided cost of solar energy to the hourly prices to develop a representative index year. The price shape is included in the Company's revised RVOS workbook, and results in a real levelized energy value for RVOS of $25.30 per MWh.

Q. What did Order No. 17-357 say about incorporating hydro conditions into the RVOS energy value?

A. Order No. 17-357 stated the energy data input for future energy prices should reflect a distribution of potential hydro conditions. The Commission directed 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.

Q. How did Idaho Power scale energy values to represent the average energy price under a range of hydro conditions?

A. Idaho Power developed an average energy price by considering the effects on price, if any, of five separate representative hydro conditions. The Company sorted 82 years of streamflow data into percentiles and determined the effect on the electric price for each of the following hydro conditions: 10th percentile, 30th percentile, 50th percentile, 70th percentile, and 90th percentile. Specifically, the Company completed five simulations in AURORA to determine annual average Mid-C electric prices for 2018-2034, extrapolated to 2042,[2] under each of the hydro conditions noted above, with all other inputs held constant. The Company calculated the differentials in Mid-C prices between each of the simulations and the median hydro condition and applied those differentials to the current approved Cogeneration and Small Power Production Standard Contract Rates, Schedule 85 ("Standard Contract Rates") for a solar QF to develop a range of hydro-varied energy prices for 2018-2042. Finally, the Company averaged the resulting range of prices to determine annual average prices under a range of hydro conditions. The average prices under a range of hydro conditions were used to populate the Annual Average Energy Price ($/MWh nominal) on the "General Input" tab of the RVOS workbook.

Q. Did Staff suggest an alternate approach to modeling hydro variability?

[2] Order No. 17-357 directs utilities to use a 25-year timeframe for RVOS calculations; however, Idaho Power's IRP horizon is limited to 20 years, as are QF commitments. The AURORA simulations used to develop the average price under a range of hydro conditions were completed as part of the 2015 IRP process, and therefore, produced Mid-C electric prices for the 20-year timeframe of 2015-2034. Idaho Power extrapolated Mid-C prices for the years 2035-2042, as well as Standard Contract Rates for the year 2042, using a compound average growth rate.

A. Yes. Staff commented that Idaho Power's hydro variability modeling is linear and not random and recommended that Idaho Power modify its hydro variability modeling to use a random sampling of hydro conditions.

Q. Does Idaho Power agree with Staff's recommendation for modeling hydro variability?

A. No. Randomly selecting a number of varying hydro conditions, and determining the associated power supply costs and electric prices for that sample may not accurately reflect the impacts of hydro variability that the Commission is attempting to determine. Idaho Power believes that its approach of sorting 82 years of streamflow data into a range of five representative hydro conditions, and then averaging the effect on area pricing that those representative hydro years has, complies with the order for hydro conditioning the energy prices to represent the average price under a range of hydro conditions.

Element No. 2 – Generation Capacity

Q. What is the Commission's direction for developing the generation capacity component of the RVOS?

A. For generation capacity, the Commission directed utilities to provide the capacity value and timing (deficiency date) in line with their current approved standard nonrenewable QF avoided cost capacity value. Per the current standard nonrenewable QF capacity calculation, during resource sufficient years, the utility uses forward market prices to calculate avoided cost prices. 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. Order No. 17-357 at 6-7.

Q. Did Idaho Power determine the generation capacity value in accordance with the standard nonrenewable QF avoided cost approach?

A. Yes. For the Company's initial RVOS filing, the Company used the current approved avoided capacity costs from its Standard Contract Rates in the RVOS calculation, beginning in the first year of deficiency, 2024, as established in the Company's 2015 IRP. Per the Company's current approved Standard Contract Rates, the capacity cost of Idaho Power's avoided proxy resource, a combined cycle combustion turbine, in 2024 is $92.90 per kilowatt-year ("kW-year"). This value was included in the initial RVOS workbook for the Cost of Marginal Capacity on the "General Inputs" tab.

Q. Were comments regarding the development of the RVOS generation capacity component provided by Staff or other intervening parties?

A. No party suggested an alternative approach to determining the generation capacity component; however, OSEIA did provide comments regarding the determination of the Resource-Balance Year.

Q. What was the Commission's direction regarding the determination of the capacity Resource-Balance year?

A. The Commission recommended retaining 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 and to also remove incremental distributed solar PV from the load forecast for their initial RVOS filings. In Idaho Power's initial RVOS filing, the Company used the current approved avoided capacity costs from its Standard Contract Rates in the RVOS calculation, beginning in the first year of deficiency, 2024, as determined in the Company's 2015 IRP. The load forecast used by Idaho Power in the 2015 IRP did not include an adjustment for incremental distributed solar PV; therefore, distributed solar PV had no impact on capacity deficiency timing.

Q. Did Idaho Power update the RVOS calculation with the resource deficiency date identified in the 2017 IRP?

A. Yes. The acknowledged 2017 IRP reflects a first deficiency year of 2 026. Like the 2015 IRP, the load forecast used by Idaho Power in the 2017 IRP did not include an adjustment for incremental distributed solar PV; therefore, distributed solar PV had no impact on capacity deficiency timing. Per the Company's current approved Standard Contract Rates, the capacity cost of Idaho Power's avoided proxy resource, a combined cycle combustion turbine, in 2026 is $94.93 per kW-year. This value has been updated in the revised RVOS workbook. The Company also updated the escalation rate and nominal discount rate to align with the 2017 IRP assumptions. Based on these revisions, the real levelized value of generation capacity is $12.98 per MWh, as shown on the table on page 3.

Q. What were OSEIA's comments regarding the determination of the resource-balance year?

A. OSEIA recommends advancing the resource-balance year when Idaho Power will need capacity by four years to recognize the shorter lead times and small capacity increments that OSEIA claims distributed solar resources can provide. OSEIA also recommends using the capacity factor method used to calculate solar's contribution to avoided generation capacity costs in UM 1719 (Investigation of Renewable Generator's Contribution to Capacity) to calculate the generation capacity value for RVOS.

Q. Does Idaho Power agree with OSEIA's recommendations?

A. No. OSEIA's proposal of shortening the capacity deficit period by overbuilding the system early with new distributed solar resources is not appropriate for Idaho Power's Oregon customers. OSEIA's conjecture that building distributed solar resources early will average out by eliminating overbuilding when large "lumpy" thermal utility scale resources are needed is based on flawed and unlikely assumptions.

Q. Please explain why Idaho Power believes OSEIA's assumptions are flawed or unlikely.

A. OSEIA's assumption that utility scale resources are "lumpy" is not necessarily accurate. Utility scale resources can be scaled to match the annual increases in capacity needs, thus avoiding excess capacity. For example, small utility scale peaking units are fully capable of adding capacity to a system as needed in a very cost-effective manner. Also, utility scale solar projects are shown to be a lower cost option than distributed solar resources. For example, as shown in the Idaho Power's most recent 2017 IRP,[3] the cost of a utility scale solar PV project has a levelized cost of energy of $74 per MWh and can be built with relatively short engineering, procurement, and construction (EPC) lead times as compared to the large "lumpy" utility generation plants assumed in the OSEIA RVOS proposal of $108.17 per MWh. Additionally, the economies of scale and efficiencies inherent in building larger facilities are shown to be more cost-effective for customers when viewed over a longer period, as is shown in the Idaho Power 2017 IRP analysis. The Idaho Power 2017 IRP compared portfolios which added large facilities that resulted in near-term excess capacity to building just-in-time resources to follow load growth. The Company's 2017 IRP preferred portfolio, Portfolio P7, includes a larger scaled resource, a combined-cycle combustion turbine, and was still determined to be the least-cost least-risk portfolio, even when compared to portfolios with just-in-time distributed generation resources.

The speculative future described by OSEIA, in which the addition of hundreds of megawatts ("MW") of distributed generation capacity on Idaho Power's system in Oregon is capable of eliminating the need for additional system utility scale capacity

[3] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf page 89

and energy resources, is very unlikely. Compensating program developers and participants for speculative outcomes is not in the general customers' interest.

Idaho Power maintains that for the development of the generation capacity component of the RVOS, the Company should provide the capacity value and timing (deficiency date) in line with their current approved standard nonrenewable QF avoided cost capacity value, as directed by the Commission. Order No. 17-357 at 6-7.

Element No. 3 – T&D Capacity

Q. What was the Commission's direction for developing the T&D capacity component of the RVOS?

A. The Commission directed that the 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.

Q. What did Idaho Power provide as its initial T&D capacity component of the RVOS?

A. The Company's initial value for the T&D capacity component of the RVOS was based on an analysis performed as part of the 2017 IRP, which estimated T&D deferral benefits associated with energy efficiency.

Q. Did Staff provide comments regarding Idaho Power's approach?

A. Yes. Staff commented that Idaho Power's use of the T&D deferral value for energy efficiency was inappropriate. Staff suggested that Idaho Power should use its marginal cost of service ("MCOS") study for the T&D deferral values.

Q. Does Idaho Power agree with Staff's criticism?

A. Idaho Power understands Staff's concern about using values derived for the use of energy efficiency to determine the deferral value of PV solar. Idaho Power used the energy efficiency value as a temporary placeholder while Idaho Power determined a reasonable T&D capacity deferral value relative to PV solar for its Oregon service area. Idaho Power strongly disagrees with using the MCOS" to approximate the T&D capacity element of the RVOS. Most of the recent Oregon service area investments included in the MCOS have been for maintenance and reliability improvements which cannot be deferred by PV solar generation. An MCOS approach will result in significant overstatement of the T&D deferral value of PV solar and adversely impact Idaho Power's Oregon customers.

Q. Does Idaho Power have an updated value for the T&D capacity deferral value?

A. Yes. A T&D capacity deferral value of $0.54 per MWh was determined following the E3 recommended method.

Q. How was the E3 method followed?

A. The distribution capacity component of the RVOS was calculated by analyzing the 13 substation distribution transformers with existing distribution connected solar photovoltaic ("PV") generation in the Idaho Power Oregon service territory ("Oregon System").

Q. Do any of these substation distribution transformers have Public Utility Regulatory Policies Act of 1978 ("PURPA") generation?

A. Yes. Six of the distribution transformers serve circuits with PURPA PV solar generation. The amount of PURPA PV solar generation causes these transformers to register reverse power flow. Additionally, three out of these six transformers record higher peak loading during the reverse power flow. The addition of PV solar generation on these three transformers will increase their peak loading.

Q. What is the impact of PURPA PV solar?

A. The large size of the PURPA PV generation eliminates the possibility of residential or commercial PV to defer T&D capacity additions on these six distribution transformers.

Q. How were the remaining seven transformers evaluated?

A. The load of the remaining seven transformers was analyzed for the ability to defer capacity investment following the E3 recommended method. The contribution of the existing net-meter solar generation and Oregon feed-in tariff solar generation, collectively referred to as PV solar generation, was subtracted from each load profile. The annual peak load was forecasted over the 25-year period.

Q. What were the results of this analysis?

A. Three transformers have sufficient installed capacity to serve the forecasted load for the 25-year period and four were found to be capacity limited within the period; however, the annual forecasted growth on three of the four capacity limited transformers exceeds the current installed PV solar generation capacity. Thus, it is not possible to defer the future capacity investments on six of the seven transformers.

Q. What is the net present value ("NPV") of the remaining transformer?

A. The load at the remaining substation transformer was analyzed at a 2.47 percent forecasted average annual growth rate. The current installed PV solar generation may defer a $73,000 infrastructure investment approximately seven years from 2021 to 2028. The deferral savings are estimated to be $17,499, which results in a $1,467 annualized NPV.

Q. What is the distribution capacity deferral value?

A. The annual distribution capacity deferral value was determined by dividing the annual NPV by the effective reduction in peak power of 377 kilowatts. The resulting $3.89 per kW-year value was input into the E3 spreadsheet, provided by the Commission, to adjust for losses and peak contribution. The transmission and distribution allocation factors were also adjusted to 21.4 percent based on the Idaho Power load and solar profiles. The resulting real levelized distribution capacity deferral value is $0.54 per MWh, as shown on the table on page 3.

Q. What about the transmission capacity deferral value?

A. The Oregon portion of the Idaho Power system has a winter load peak. This load peak occurs around 8:00 a.m. Because of the time of day and lack of sunlight, installed PV solar generation cannot significantly contribute to decreasing the Oregon system peak load. An inability to reduce the Oregon system load peak will not defer transmission infrastructure investments. Thus, the transmission capacity deferral value is $0.00 per MWh.

Q. Did Idaho Power validate the T&D capacity deferral value using another approach?

A. Yes. The E3 recommended methodology was validated by analyzing the T&D capacity deferral value for varying amounts of additional PV solar penetration throughout Idaho Power's Oregon service territory.

Q. How was this accomplished?

A. The T&D capacity deferral of energy efficiency methodology was used as a base and altered in the following ways for the PV solar application:

- The method was extended to a 20-year period by including both historical and forecasted infrastructure investments. The benefits of the 20-year period are the inclusion of both economic growth and recession periods, and alignment with the typical performance life of PV panels.
- Locations with infrastructure investments that could potentially be deferred by PV over the stated period were identified. An infrastructure investment deferment was determined through comparison of the asset's load peak to the effective solar contribution at that time of day.
- PV penetration levels of 0-100 percent of the load peak were analyzed. Average solar project sizes in Oregon were used for each customer class.

Q. How was the annual T&D capacity deferral value determined?

A. The average annual infrastructure investment deferrals for the Oregon system was determined by identifying the T&D capacity investments that resulted from peak load growth or may result based on forecasted growth over a 20-year period. The deferred investments are estimated for each deferral and are gathered into an average annualized value for the period.

Q. How was the annual T&D capacity deferral value selected?

A. The average annualized value is divided by the PV capacity installed. Figure 1 displays the T&D capacity deferral value of PV solar. The value drops off gradually beyond a penetration level of about 5 percent. Based on the Oregon system's current PV penetration of approximately 0.5 percent, the range from 0-5 percent was selected resulting in a $0.35 per MWh average distribution capacity deferral value, as shown in Figure 2.

Figure 1: T&D Capacity Deferral for Penetration from 0 to 100 percent of Peak Load

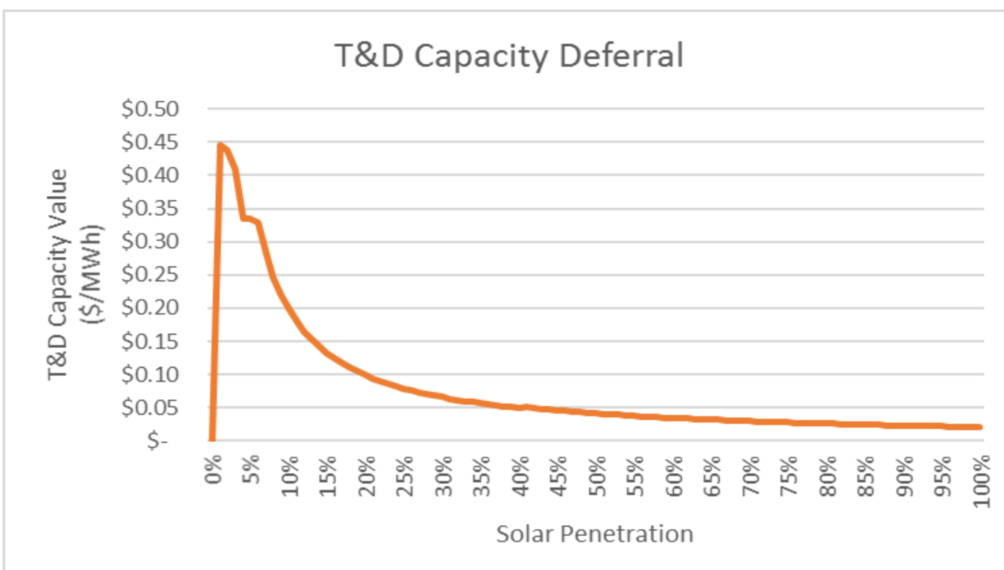
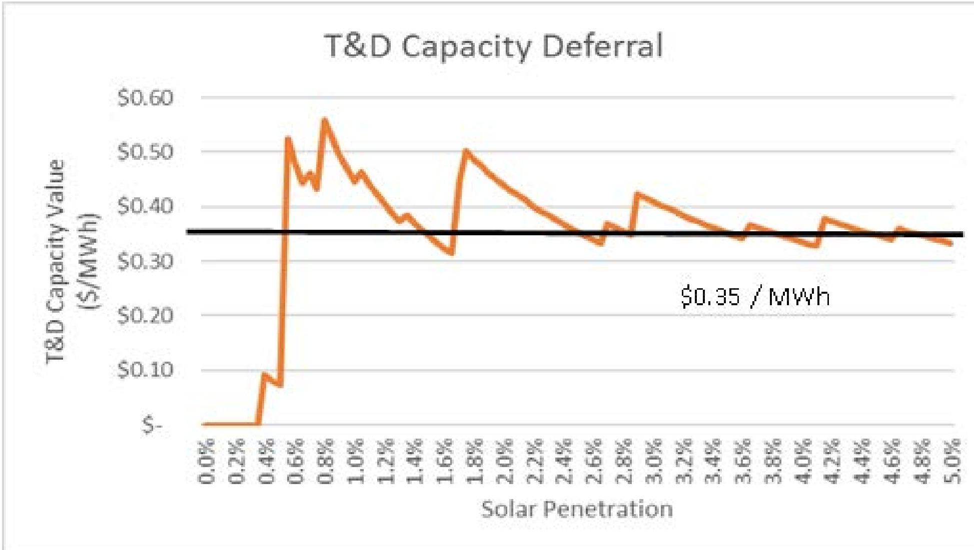


Figure 2: T&D Capacity Deferral for Penetration from 0 to 5 percent of Peak Load



Q. Were there additional suggestions or criticisms on Idaho Power's approach for the T&D deferral value?

A. Yes. OSEIA commented that Idaho Power limits the avoided T&D costs only to the costs of deferring T&D upgrades that are being planned today. OSEIA states that solar distributed generation has a useful life of 20-30 years, and as a result can avoid future T&D upgrades that are not within the shorter time horizons identified in Idaho Power's T&D planning and budgeting. OSEIA suggests that Idaho Power should use Portland General Electric's ("PGE") approach of using current Federal Energy Regulatory Commission ("FERC") approved bulk transmission rates as a proxy for marginal transmission capacity.

Q. Does Idaho Power agree with OSEIA's longer period suggestion?

A. Idaho Power agrees with OSEIA that representing a longer period is an improvement in the determination of the T&D analysis. The E3 recommended methodology and the Idaho Power validation methodology used a 25 and 20-year period, respectively.

Q. Does Idaho Power agree with OSEIA's transmission proxy suggestion?

A. Idaho Power disagrees with the use of FERC-approved bulk transmission rates as a proxy for marginal transmission capacity. As answered above, Idaho Power's Oregon system peaks during winter mornings at a time when there is little to no PV solar generation.

Element No. 4 – Line Losses

Q. What was the Commission's direction for calculating the line losses component of the RVOS?

A. For line losses, the Commission directed 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. The Commission noted that it does not expect a true hourly value to this element, but asks utilities to provide the most granular value they reasonably can, inclusive of daytime and seasonal variation, and to provide an explanation of the value.

Q. How did Idaho Power incorporate Avoided Line Losses into its initial RVOS value?

A. Using loss data collected for calendar year 2012, Idaho Power populated the hourly averages of line losses using the Electricity System Losses table on the "General Inputs" tab of the RVOS workbook. The loss values represented the percentage of produced energy consumed as losses in the transmission, distribution substation, primary distribution, and secondary distribution facilities owned by Idaho Power, and included both wire losses and transformer core losses. The loss values used were average loss percentages and reflected summer and winter seasonality and hourly on-peak, mid-peak and off-peak differences.

Q. Did any of the intervening parties provide suggestions or criticism on Idaho Power's approach?

A. Yes. OSEIA recommends the use of marginal line losses, rather than average line loss factors. OSEIA arbitrarily calculates marginal line losses by increasing the average loss factors by 50 percent to "capture the higher marginal losses avoided by solar DG resources."

Q. Does Idaho Power agree with OSEIA's suggestions?

A. Idaho Power agrees that using marginal line losses is appropriate for RVOS valuation, but disagrees with OSEIA's marginal loss value.

Q. What is Idaho Power's recommendation on a method of including avoided line losses into the RVOS value?

A. Idaho Power has performed additional analysis and has made two changes to the method by which the avoided line loss component is calculated since the filing of the original RVOS workbook:

- The appropriateness of using a loss factor that includes losses in the secondary distribution facilities owned by Idaho Power was evaluated. Based on that analysis, Idaho Power recommends using loss factors that represent the percent of energy that is consumed as losses in the transmission, distribution substation, and primary distribution facilities only, and excludes losses in the secondary distribution facilities. Losses in the secondary distribution facilities are excluded as these losses are not avoided with the addition of distributed solar. Distributed solar is not entirely consumed at the site of generation. Idaho Power estimates that more than half of the energy from the Oregon PV Pilot is consumed at a location other than at the generation location. The excess generation incurs losses when it is sent through the distribution secondary system to be used by other customers.
- A marginal loss factor was developed using loss data collected for calendar year 2012. The marginal loss factor represents the amount of losses avoided in the

transmission, substation, and primary distribution facilities as a percent of an incremental change in net load served by the distribution primary facilities due to the presence of distributed PV solar. The change in net load is assumed as a change in annual average load served by the distribution primary facilities owned by Idaho Power.

Q. What is the value for avoided line losses?

A. The marginal loss factor is 8.1 percent. Based on the updated loss factor, Idaho Power's revised real levelized value for losses is $2.05 per MWh, as shown on the table on page 3.

Element No. 5 – Administration

Q. What was the Commission's direction for calculating the administration component of the RVOS?

A. Utilities were to develop estimates of the direct, incremental costs of administering solar PV programs, including staffing, software, incremental distribution investments, and other utility costs.

Q. What was Idaho Power's estimate of the direct, incremental costs of administering its solar PV programs in Oregon?

A. Idaho Power determined its estimate for the direct, incremental costs of administering solar PV programs in Oregon by reviewing the actual costs incurred for the Oregon PV Pilot in 2016. For the Company's initial RVOS filing, the Company's estimate of administering solar PV programs was $47.77 per MWh, escalated at the 2015 IRP inflation rate of 2.2 percent annually. The $47.77 per MWh cost is based on 2016 actual expenses for the Oregon PV Pilot, 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. It is Idaho Power's understanding that the RVOS will be used for compensation for participants in the Oregon PV Pilot when the existing projects seek renewal contracts. As these are the actual costs of administering these projects, Idaho Power believes it is appropriate to reflect these costs in the administration component of the RVOS when the RVOS is used for the Oregon PV Pilot. As stated in my Direct testimony, if the RVOS is used for other purposes where the communication costs are provided for by other means than inclusion in administrative expenses, then the communication costs should be removed from the RVOS calculation.

Q. Did Idaho Power consider any other estimates for calculating the administration component of the RVOS?

A. Yes. Idaho Power recognizes that the administration component is relatively large and may be driving down the RVOS calculation. For a comparative analysis, the Company removed $23,899 of the administration costs associated with communication service fees, which represents 62 percent of the total administration costs. The Company believes that while these costs are appropriately included in this initial RVOS calculation because they are actual costs being incurred for participants in the Oregon PV Pilot, these same costs may not be included once the pilot is completed. Removal of these costs from the administration component of the revised RVOS calculation resulted in a net levelized RVOS of $23.94 per MWh.

Q. Was this reduced amount of administration costs the amount used for the Company's initial and revised RVOS calculations?

A. No. This reduced amount for administration costs may be considered in future RVOS calculations; however, for the Company's initial and revised RVOS calculations, all administration costs have been included, resulting in a Company estimate of administering solar PV programs of $47.77 per MWh, escalated at the 2015 IRP inflation rate of 2.2 percent annually.

Q. Did parties agree with Idaho Power's determination of administrative costs?

A. No. Staff does not support the application of the annual costs of a specific past program to determine the costs of a future program using RVOS-based rates. Staff recommends that Idaho Power use the incremental costs of administering net metering programs or other "opt-in" customer programs to estimate RVOS administrative costs.

CUB commented that Idaho Power should not use the actual administrative costs for running the Oregon PV Pilot. CUB welcomes Commission direction for a more appropriate way for Idaho Power to calculate administrative costs.

ODOE stated that while Idaho Power justifies the administrative costs based on actual experience in the Oregon PV Pilot, Idaho Power and the Commission should consider strategies to reevaluate or mitigate administrative costs.

RNW commented that Idaho Power's use of actual costs for the Oregon PV Pilot did not make sense in the context of UM 1911. The earliest year a participant in the Oregon PV Pilot would be eligible for compensation "at a rate equal to the resource value" is 2024. It was therefore not clear why Idaho Power considered the Oregon PV Pilot when trying to determine the 25-year marginal, levelized value for administrative costs for a generic, small-scale solar resource installed in 2017. RNW made no recommendation on how to value the administrative cost element of RVOS.

OSEIA stated that the economies of scale have been achieved in administering solar programs. Idaho Power's administrative costs are unreasonable to use for a well-established solar program that has moved beyond the pilot stage. Idaho Power should use PacifiCorp's administrative costs of about $2.00 per MWh because they are in line with those of other utilities in the west with active solar programs.

Q. Does Idaho Power agree with the parties' criticism and suggestions?

A. Idaho Power understands the parties' adverse reaction to the Company's administrative costs in the Oregon PV program; however, they are reflective of the actual costs incurred to administer that program. While Idaho Power's administration cost estimate may appear out of line when compared to the estimates from PGE and PacifiCorp, it is important to remember that Idaho Power's Oregon service area is significantly different than the Oregon service areas of PGE and PacifiCorp.

The Idaho Power Oregon service area consists of less than 19,000 customers. Idaho Power has a relatively small customer base to socialize the costs of the type of programs the RVOS is intended to value. While the economies of scale may help to drive down the average administration costs incurred to support program participants in the Idaho Power Oregon service area, it may also have an adverse impact on Idaho Power's remaining Oregon customers, by increasing overall costs.

It is Idaho Power's understanding that the determination of the RVOS is to be used as compensation for the energy provided by the participants of the Oregon PV Pilot at the end of the 15-year fixed term contract. The administration costs disclosed by Idaho Power for the RVOS model evaluation are the actual administration costs incurred for those participants, and would be ongoing based upon the current meter configuration established for that program. If the Commission determines not to include those costs for the ongoing payments for the energy provided by the participants of the Oregon PV Pilot, then those costs would be recovered from the remaining Oregon customers. Idaho Power maintains that the administration costs included in its initial and revised RVOS filings represent the appropriate value to be included in the RVOS. The Company did update the inflation rate to align with the 2017 IRP, which is 2.1 percent. Updating the inflation rate did not impact the real levelized value of the administration cost element.

Element No. 6 – Integration

Q. What was the Commission's direction for calculating the integration component of the RVOS?

A. The Commission directed utilities to estimate integration costs based on acknowledged integration studies.

Q. Did Idaho Power comply with the Commission's direction for determining the integration component of the RVOS?

A. Yes. Idaho Power used the current Commission-approved solar integration costs included in the development of the Company's Standard Contract Rates. The values reflected in the Company's Standard Contract Rates were derived from an integration cost study which was published in the Idaho Power Company Solar Integration Study Report dated April 2016. The RVOS calculation includes an integration cost of $0.56 per MWh, for projects beginning in 2018 at the Company's current solar penetration level of 301-400 MW, and is escalated annually at 2.2 percent per the E3 workbook methodology. No intervening party provided an objection to the Company's determination of integration costs in their comments.

<u>Element No. 7 – Market Price Response</u>

Q. What was the Commission's direction for calculating the market price response component of the RVOS?

A. The Commission directed Staff to coordinate or facilitate use of E3's model to create a proxy value for market price response to increased solar PV production that utilities will use in their RVOS calculations. Staff sent an email to stakeholders in this docket on November 7, 2017, to provide direction on this component. The email included guidance from Arne Olson of E3, in which he recommended that utilities use one of two options for calculating the market price response component in their initial RVOS calculations.

The first option was to use a market price elasticity of -0.001 to -0.002 for each MWh of renewable energy. The elasticity is measured separately for heavy-load and light-load hours. The second option was for utilities to complete sequential runs in a production simulation model, such as AURORA, with the addition of a significant enough increment of solar generation to affect the calculated market price during each hour. The price differences would then be used to derive a market price elasticity per MWh of energy produced from customer-owned solar resources. Mr. Olson noted that with either option, the change in market price would be multiplied by the utility's net short or long position during each hour, i.e., the change in market price would be a benefit if the utility is short and a cost if the utility is long.

Q. Which method did Idaho Power use to determine the market price response component of the RVOS?

A. Idaho Power evaluated AURORA output to determine the hourly imports and exports from the Idaho Power system. The AURORA daylight hour import-export analysis indicated the majority of hours showed exports and that Idaho Power sold more energy to the market than it purchased from the market, resulting in a negative value for the market price response component of the RVOS calculation. Based on the indication that the market price response component was negative, Idaho Power used a market price elasticity of -0.001 per MWh for the market price response component to the RVOS as suggested by Mr. Olson in the November 7, 2017, email from Staff.

Q. What were parties' comments regarding Idaho Power's approach?

A. Staff stated that Idaho Power does not consider the solar development in the service territory of other utilities and that Idaho Power should modify its calculation of the market price response to account for solar development in other service territories as well as its own.

RNW stated that Idaho Power's reliance on the Oregon PV Pilot to value market price response was not appropriate, even if Idaho Power was correct in its assessment of how the 0.41 MW was not significant enough to influence market prices;

however, RNW made no recommendation on how to value the market price response element of RVOS.

OSEIA suggested that Idaho Power should use PGE's calculation of the market price response value of 3.8 percent of avoided energy costs because it aligned with other calculations of this benefit that have been made in the New England Independent System Operator ("ISO") market.

Q. Does Idaho Power agree with the parties' criticism or suggestions?

A. No. Idaho Power adamantly disagrees with OSEIA's suggestion of using PGE's calculation of market price response values, as they aligned with calculations found in the New England ISO market, because Idaho Power is not a member of the New England ISO (nor any other ISO for that matter), and because PGE and Idaho Power's interaction with the market may be completely different.

Regarding Staff's suggestion, lower market prices which may result from future regional solar development would reasonably reduce the energy value component calculated in Element No. 1. Thus, the result would be a netting of the cost of energy and the benefit of any market price response hypothesized in the RVOS workbook.

Q. What does Idaho Power propose to use for the market price response component of the RVOS?

A. Based on the Company's AURORA analysis which indicated the majority of hours showed exports and that Idaho Power sold more energy to the market than it purchased from the market, a negative value for the market price response component of the RVOS calculation is most appropriate. Idaho Power reasserts that a market price elasticity of -0.001 per MWh for the market price response component to the RVOS as suggested by Mr. Olson in the November 7, 2017, email from Staff, for the RVOS facilities located in the Idaho Power Oregon service area is appropriate.

Element No. 8 – Avoided Hedge Value

Q. What was the Commission's direction for calculating the avoided hedge value component of the RVOS?

A. The Commission directed utilities to use E3's proxy value of 5 percent to reflect the avoided cost of utility hedging activities.

Q. Did Idaho Power use the 5 percent proxy value for the avoided cost of hedging activities in its RVOS calculation?

A. Yes. The 5 percent proxy value was included as an input on the "General Inputs" tab of the RVOS workbook.

Q. Did intervening parties provide comments on Idaho Power's use of the 5 percent proxy as directed by the Commission?

A. Yes. OSEIA applied a hedge value methodology developed by Clean Power Research in the Maine Distributed Solar Valuation Study commissioned by the Maine Public Utilities Commission. The methodology uses the study's gas commodity price forecasts, U.S. Treasuries (at current yields) as the risk-free investments, Idaho Power's weighted average cost of capital, and a marginal heat rate of 7,500 Btu per kilowatt-hour. OSEIA assigned a hedge value of $20.69 for Idaho Power.

Q. Does Idaho Power agree with OSEIA's determination of a hedge value for Idaho Power?

A. No. The hedge value proposed by OSEIA based on a Maine Distributed Solar Valuation Study is not appropriate for Idaho Power's Oregon customers. Idaho Power has a different system and risk profile than the Maine study analyzes. Additionally, the historic natural gas prices shown by OSEIA appear significantly higher than recent Energy Information Administration (EIA) natural gas price forecasts used by Idaho Power.

Q. Does Idaho Power recommend a change in the value used for the avoided cost of hedging activities in its RVOS calculation?

A. No, not at this time; however, as stated in prior testimony, Idaho Power has a specific Risk Management Policy which includes a prescribed process of when to initiate future power market purchases and sales. The 5 percent premium value of future energy purchases is not consistent with Idaho Power's Risk Management Policy, and therefore, does not reflect the hedging activity on Idaho Power's system. The Company believes that using a value of zero for the avoided hedge value is more appropriate for Idaho Power's system; however, at this point, Idaho Power continues to comply with the Commission's directive and use the 5 percent proxy value for the RVOS determination. Although Idaho Power did not update the hedge value, this element did change from the Company's initial RVOS filing as result of updating the energy values to account for an hourly price shape. The resulting hedge value is $1.26 per MWh, as shown on the table on page 3.

Element No. 9 – Environmental Compliance

Q. What was the Commission's direction for calculating the environmental compliance component of the RVOS?

A. The Commission directed utilities to calculate a value for environmental compliance for informational purposes, to be used as a placeholder in their initial RVOS calculations. The utilities were to estimate the avoided cost based on a reduction in carbon emissions from the marginal generating unit with the carbon regulation assumptions from their IRPs.

Q. What value did Idaho Power calculate for environmental compliance?

A. Idaho Power used a value of zero for environmental compliance. Currently, Idaho Power has no environmental compliance costs; therefore, no environmental compliance costs are avoided with additional solar generation. A zero value is consistent with Idaho Power's 2015 and 2017 IRPs.

Q. Did Staff or other parties provide comments regarding Idaho Power's determination of an environmental compliance value?

A. Yes. Staff does not agree with Idaho Power's approach to calculating environmental compliance based on its 2015 IRP, which accounts for the cost of carbon through the compliance cost of the Clean Power Plan. Staff believes this is insufficient in light of current events and the Trump administration's efforts to repeal the Clean Power Plan. Staff recommends that Idaho Power use the carbon-added data from its 2013 IRP until Idaho Power develops a new cost associated with carbon regulation.

OSEIA commented that Idaho Power should use the avoided carbon compliance cost calculated by PGE because it is reasonable to assume that any compliance regime for carbon emissions will apply to all utilities in Oregon.

Q. Does Idaho Power agree with the parties' recommendations?

A. No. Idaho Power's Oregon customers are not currently impacted by the cost of carbon. To fairly price the RVOS, only legislation or regulations currently in effect should be included in the environmental values. Including values of speculative legislation or regulation in the contract term is inappropriate. Locking in speculative costs into a reimbursement rate that is not a cost currently incurred is unjustly enriching developers at the expense of customers.

With regard to OSEIA's recommendation, Idaho Power opposes the inherent assumption that any compliance regime for carbon emission would impact all Oregon utilities in the same way, and therefore, the Company should adopt PGE's cost calculation. Idaho Power currently forecasts compliance costs based on the proposed Oregon cap-and-invest legislation, which would not impact RVOS projects until after 2031.

The Company disagrees with Staff's suggestion of looking back to an earlier IRP for a valuation of carbon as that would be using information that is outdated and speculative. The 2013 IRP used carbon pricing in line with the legislation that was being proposed at that time. There is no current pending federal carbon tax legislation on which to base a carbon tax number. A carbon tax proposal from Idaho Power would be overly speculative on Idaho Power's part.

Idaho Power continues to maintain that an environmental compliance value of zero for current RVOS calculation is the most appropriate for Idaho Power's Oregon customers.

Element No. 10 – RPS Compliance

Q. What was the Commission's direction for calculating the RPS compliance component of the RVOS?

A. The Commission directed utilities to initially assign a zero value for RPS compliance. The zero value is intended be a placeholder until it can be revisited and assigned a methodology as part of Phase II in this docket.

Q. Did Idaho Power assign a value of zero to the RPS compliance component of the RVOS calculation?

A. Yes. Idaho Power does not have an RPS in the state of Idaho and the Company would already be in compliance with the Oregon RPS requirements to be met in 2025 without incurring additional costs.

Element No. 11 – Grid Services

Q. What was the Commission's direction for calculating the grid services component of the RVOS?

A. The Commission directed utilities to initially assign a zero value for grid services. The element of grid services will be retained to capture the potential incremental system benefits from solar PV in the future.

Q. Did Idaho Power assign a value of zero to the grid services component of the RVOS calculation?

A. Yes.

II. UTILITY SCALE ALTERNATIVE

Q. What is the Commission's direction regarding alternative RVOS calculations for utility scale solar resources?

A. The Commission stated, as a reference point only, that utilities should provide a separate workbook with an RVOS calculation assuming a utility scale solar proxy to replace all elements, and remove the cost components for T&D capacity, administration, and line losses, which are benefits/costs that rooftop solar provides that utility scale solar does not. The Commission also noted that utilities should explain their utility scale proxy and how it relates to their IRPs.

Q. Did Idaho Power develop an alternative RVOS calculation assuming a utility scale solar proxy?

A. Yes. Idaho Power's RVOS calculation assuming a utility scale solar proxy results in a levelized net RVOS of $45.01 per MWh.

Q. Please explain how Idaho Power developed the alternative RVOS calculation.

A. Idaho Power assumed a 30 MW utility scale single-axis tracking project, which is consistent with Idaho Power's 2017 IRP view of a representative size for utility scale solar projects the Company might contemplate in the future.

The utility scale RVOS calculation utilizes a representative 12-month x 24-hour solar output capacity profile submitted by a 15 MW Oregon solar PURPA project currently under contract. Each value within the 12-month x 24-hour solar output capacity profile was doubled to represent a 30 MW project. The solar output capacity profile was used to update the hourly input solar profile within the utility scale RVOS workbook.

Those elements that relate to the benefits of a distributed system, which include T&D capacity, line losses, and administration costs were eliminated from the utility scale RVOS calculation, per the Commission directive.

All other element inputs for the utility scale RVOS calculation were consistent with the inputs used in the Company's RVOS calculation for a standard size project. The resulting levelized RVOS calculation for a utility scale solar proxy was $45.01 per MWh.

Q. Did Staff or other parties provide comments regarding Idaho Power's utility scale RVOS calculation?

A. Yes. Staff and OSEIA explain that Idaho Power simply removed the administrative cost, avoided T&D, and line loss components from the utility scale RVOS calculation and held all other values constant with its RVOS calculation for a standard size project. Staff and OSEIA state that Idaho Power should have used costs and performance statistics associated with a utility scale solar proxy to replace all components of the RVOS calculation except the administrative costs, avoided T&D, and line losses components.

Staff does note that the request to provide a utility scale RVOS as a reference value may not have been broadly understood by all stakeholders and Staff sees room for Idaho Power to adjust the utility scale RVOS either within reply testimony or the next phase of RVOS. Additionally, Staff suggests that the Commission consider clarifying the direction and intent of the utility scale RVOS to the utilities.[4] Specifically, Staff states:

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

[4] Staff/100, Andrus/57

- 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 a 50 MW or larger 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.

Idaho Power agrees with Staff that additional clarification is needed on the intent, direction, and assumptions to be used for the calculation of a utility scale RVOS. Idaho Power intends to provide an updated utility scale RVOS calculation, incorporating any additional guidance from the Commission, in the next Phase of RVOS, as suggested by Staff.

Q. Does this conclude your testimony?

A. Yes, it does.