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July 26, 2018

VIA ELECTRONIC FILING

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 – In the Matter of IDAHO POWER COMPANY, Resource Value of Solar

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic copy of Idaho Power Company's Opening Brief.

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Legal Assistant

Attachment

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM 1911

In the Matter of IDAHO POWER COMPANY, Resource Value of Solar.	**Idaho Power Company's Opening Brief**

I. <u>INTRODUCTION</u>

This docket is one of three utility-specific dockets opened by the Public Utility Commission of Oregon (Commission) as Phase II of its investigation into the resource value of solar (RVOS). The Commission initiated the RVOS investigation after the legislature instructed the Commission to establish pilot solar generation programs for the three major investor-owned electric utilities in Oregon.[1] The Oregon legislature also directed the Commission to provide biannual reports on the pilot programs to the legislature, including estimates of the resource value of solar.[2] After the Commission's first report to the legislature, it opened Phase I of the RVOS proceeding in UM 1716 and committed to developing "a deep understanding" of how to accurately value solar.[3]

In Phase I, the Commission conducted a broad investigation into the elements constituting the RVOS. To support this investigation, the Commission hired Energy and Environmental Economics, Inc. (E3) to identify the critical RVOS elements and develop a proposed RVOS model. After several rounds of testimony and a hearing, the Commission

[1] *In the Matter of the Public Utility Commission of Oregon Investigation to Determine the Resource Value of Solar*, Docket No. UM 1716, Initial Application (Jan. 27, 2015); HB 2893, 77th Or. Leg., 2013 Reg. Sess.

[2] HB 2941 78th Or. Leg., 2015 Reg. Sess.

[3] Docket No. UM 1716, Order No. 15-296 at 2 (Sept. 28, 2015).

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adopted E3's proposed model, with certain revisions.[4] In Phase II, the Commission has directed each utility to apply the model, including 11 different RVOS elements, to: (1) a generic small solar resource in the utility's service territory, and (2) a utility scale solar resource in the utility's service territory. The 11 elements are:

1. Energy
2. Generation Capacity
3. Transmission and Distribution (T&D) Capacity
4. Line Losses
5. Administration
6. Integration
7. Market Price Response
8. Hedge Value
9. Environmental Compliance
10. RPS Compliance
11. Grid Services

Idaho Power Company (Idaho Power or the Company) calculated values for each element consistent with the Commission's direction, as described below.

II. DISCUSSION

1. Application of the Elements

This discussion (1) identifies the Commission's definition and direction for applying each element; (2) explains how Idaho Power calculated each element's value; and (3) responds to issues raised by Staff and other parties to this proceeding. Idaho Power provided initial calculations for each of the RVOS elements in its Opening Testimony. In addition, in its Revised Testimony, Idaho Power provided revised calculations responding to concerns voiced by the parties, and updated inputs from the Company's recently-acknowledged 2017 IRP.[5] Table 1, below, presents the levelized net value for each element as initially calculated and as revised.

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[4] Docket No. UM 1716, Order No. 17-357 at 1 (Sept. 15, 2017).

[5] Idaho Power/200, Haener/2-3.

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Table 1: Idaho Power's RVOS Values

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**

A. Energy

The Commission directed utilities to use model energy values to reflect monthly and hourly variations, creating a 12-month x 24-hour price shape.[6] Idaho Power initially modeled this element based on hourly data from participants in Idaho Power's Oregon solar pilot project (Oregon PV Pilot), which provides actual hourly capacity output to develop the energy shape.[7] However, Staff objected that Idaho Power's energy prices resulted in a flat shape, and suggested that Idaho Power should apply additional data to develop a variable 24-hour price shape.[8] RNW also objected to modeling a new solar resource based on the Oregon PV Pilot, but made no clear recommendation on how to value the energy element.[9] And OSEIA recommended that Idaho Power use recent hourly

[6] Order No. 17-357 at 4.

[7] Idaho Power/200, Haener/4.

[8] Staff/100, Andrus/3.

[9] RNW/100, O'Brien/5-6.

prices from the Energy Imbalance Market (EIM), as PacifiCorp did, to shape its energy prices.[10]

While Idaho Power believes that using the actual hourly capacity output from the Oregon PV Pilot accurately reflects the RVOS energy value, in response to the feedback from Staff and other parties, the Company provided an alternate 24-hour price shape as well, using Mid-Columbia market prices. The price shape is included in the Company's revised RVOS workbook, and results in a real levelized energy value of $25.30 (as opposed to $29.74 in the Company's initial valuation).[11]

The Commission separately directed utilities to model energy prices based on various potential hydro conditions.[12] Idaho Power developed average energy prices using five separate representative hydro conditions. The Company developed average energy prices based on 82 years of streamflow data, and then examined the 10th percentile, 30th percentile, 50th percentile, 70th percentile, and 90th percentile to determine that hydro condition's corresponding effect on energy prices.[13] While Staff recommended selecting a random number of varying hydro conditions instead[14], Idaho Power believes that its approach of assessing a wide range of representative hydro conditions complies with the Commission's order to evaluate the impact of hydro conditions on the RVOS energy element.

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[10] OSEIA/100, Beach/5.

[11] Idaho Power/200, Haener/5.

[12] Order No. 17-357 at 2.

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

[14] Staff/100, Andrus/13.

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B. Generation Capacity

For generation capacity, the Commission directed utilities to use inputs consistent with their current approved standard nonrenewable avoided cost capacity value for qualifying facilities (QFs).[15] Idaho Power used its most recently-approved capacity costs from its QF Standard Contract rates in the RVOS, which it subsequently updated to reflect the resource deficiency date identified in the 2017 IRP.[16]

OSEIA recommends advancing the deficiency date by four years due to the shorter lead times and smaller capacity increments that OSEIA attributes to solar resources.[17] This approach is based on OSEIA's observation that utility-scale resources are "lumpy" and cannot be scaled to match annual increases in capacity needs.[18] However, contrary to OSEIA's assumption, small utility-scale peaking units are fully capable of adding capacity to a system, as needed, in a cost-effective manner, while utility-scale solar PV projects, as shown in Idaho Power's most recent 2017 IRP, can be built with relatively short engineering, procurement, and construction lead times.[19] Moreover, the dramatic cost-savings associated with economies of scale demonstrate that building larger facilities is substantially more cost-effective for customers when viewed over a long period, as shown in Idaho Power's 2017 IRP analysis.[20] OSEIA's argument depends on a hypothetical future in which hundreds of additional megawatts of distributed generation

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[15] Order No. 17-357 at 6-7.

[16] Idaho Power/200, Haener/9.

[17] OSEIA/100, Beach/6.

[18] OSEIA/100, Beach/6.

[19] Idaho Power/200, Haener/10.

[20] *In the Matter of Idaho Power Company, 2017 Integrated Resource Plan*, Docket No. LC 68, Idaho Power Company's 2017 Integrated Resource Plan Application at 66 (June 30, 2017).

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capacity eliminate the need for additional utility-scale capacity, which is very unlikely and too speculative to support reliable planning for utility customers.[21]

Idaho Power continues to support the Commission's directive to use the deficiency date in line with the Company's current approved standard nonrenewable QF avoided cost capacity value.

C. T&D Capacity

The Commission directed utilities to calculate the T&D element by using a system-wide average of the costs of expanding, replacing, or upgrading T&D investments, where costs could be avoided or deferred by increased solar penetration in Oregon service areas.[22] The Company initially calculated its T&D capacity component based an analysis performed for its 2017 IRP, which estimated T&D deferral benefits associated with energy efficiency.[23]

Staff suggested that Idaho Power should use its marginal cost of service (MCOS) study to determine deferral values.[24] Idaho Power strongly disagrees with this approach, as it would substantially overstate the potential for avoidable or deferrable T&D investments. Most of the recent Oregon service area investments have been for maintenance and reliability improvements that increased solar generation would not defer.

Instead, in response to Staff's concerns, Idaho Power provided an updated T&D capacity value of $0.54/MWh, using the method recommended by E3. The distribution component used actual substation and transformer data to identify which locations were

[21] OSEIA/100, Beach/8.

[22] Order No. 17-357 at 8-9.

[23] Idaho Power/100, Haener/9.

[24] Staff/200, Andrus/8.

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capacity-limited within the 25-year study period.[25] Of the four transformers with capacity limitations, the annual forecasted growth on three of the four exceeds the current installed PV solar generation capacity. As a result, only one of the substation transformers faces an infrastructure investment deferrable by solar PV.

Idaho Power's transmission value for the RVOS is $0.00/MWh because its system is winter peaking around 8:00 a.m.—a time when solar cannot meaningfully contribute to reducing peak load.[26] Because solar cannot reduce transmission needs at peak load, it is unable to defer transmission infrastructure investments.

OSEIA argues that Idaho Power inappropriately limits avoided T&D costs to only those investments that are planned today, and therefore argues that Idaho Power should instead use Portland General Electric's (PGE) approach that uses current bulk transmission rates as a proxy for marginal transmission capacity.[27] Idaho Power agrees that longer term forecasting improves the T&D analysis; E3's recommended method uses a 25-year forecasted period, including potential future projects beyond our planning period. Additionally, Idaho Power's validation method incorporates a 20-year study period of actual capacity additions during the past fifteen years and a five-year forecast period. Both methods include suitable time horizons for analysis. Idaho Power does not believe that bulk transmission rates provide a reasonable proxy because, as noted above, Idaho Power's Oregon system peaks during winter mornings—a time when solar cannot avoid the need for transmission investments.[28]

[25] Idaho Power/200, Haener/12-13.

[26] Idaho Power/200, Haener/14.

[27] OSEIA/100, Beach/iii.

[28] Idaho Power/200, Haener/14.

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D. Line Losses

The Commission directed utilities to calculate avoidable line losses attributable to solar by developing hourly averages by month for daytime hours, when load on the system is higher, losses are greater, and solar is generating.[29] The Commission recognized that true hourly values may be impracticable, but asked for the most granular values the utilities could reasonably provide.[30] Idaho Power incorporated avoided line losses using data for calendar year 2012, representing the percentage of produced energy consumed as losses in transmission, distribution substation, primary distribution, and secondary distribution facilities.[31] These values, shown in Table 2, reflected summer and winter seasonality and hourly on-peak, mid-peak, and off-peak differences.[32]

Table 2: Line Losses as Percentage of Produced Energy Consumed

May - Oct: 2pm-7pm	Summer On-Peak	8.6%
May - Oct: 5am-2pm, 7pm-9pm	Summer Mid-Peak	8.5%
May - Oct: 9pm-5am	Summer Off-Peak	8.7%
Nov - Apr: 6am-10am, 5pm-8pm	Winter On-Peak	8.5%
Nov - Apr: 10am-5pm, 8pm-10pm	Winter Mid-Peak	8.5%
Nov - Apr: 10pm-6am	Winter Off-Peak	8.5%

OSEIA recommended using marginal line losses rather than average line loss factors, which it calculates by increasing the average loss factors by 50 percent.[33] While

[29] Order No. 17-357 at 10.

[30] Order No. 17-357 at 10.

[31] Idaho Power/200, Haener/17.

[32] Idaho Power/200, Haener/17.

[33] OSEIA/100, Beach/25-26.

Idaho Power agrees that using marginal line losses is appropriate, OSEIA's arbitrary 50 percent increase does not reflect a true marginal loss value.

Instead, Idaho Power has attempted to calculate the marginal line losses more accurately by revising two points in its analysis: ***First***, Idaho Power removed line losses on the secondary distribution facilities, as distributed solar is not entirely consumed on-site—meaning that a certain portion of the energy produced will still incur line losses at the secondary distribution level.[34] ***Second***, Idaho Power revised its analysis of 2012 calendar year line losses to account for the incremental change in net load served by the primary distribution facilities, due to the presence of distributed PV solar.[35] The change in net load represents a change in annual average load served (and thus reduced line losses) for Idaho Power's primary distribution facilities.[36] Using this adjusted approach, the marginal loss factor is 8.1 percent, and the revised real levelized value for losses is $2.05/MWh.

E. Administration

The Commission directed utilities to develop estimates of the direct, incremental costs of administering solar PV programs in the utilities' Oregon service areas, including the cost of staffing, software, incremental distribution investments, and other relevant

[34] Idaho Power/200, Haener/18.

[35] Idaho Power/200, Haener/19.

[36] Idaho Power/200, Haener/19.

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costs.[37] Idaho Power determined its estimated administrative costs by reviewing the actual costs incurred for the Oregon PV Pilot in 2016.[38]

Initially, the Company estimated the cost of administering solar PV programs at $47.77/MWh, which represents total labor costs ($14,065), communication service fees ($23,899), and other operational expenses ($638), divided by the 808 MWh of generation in the program.[39] This value was then escalated at the 2015 IRP inflation rate of 2.2 percent annually.[40] Given that Idaho Power understands that one of the uses for the RVOS will be for future iterations of the Oregon PV Pilot, relying on actual costs of administering these projects is particularly appropriate. However, if the RVOS is used in a context where communication costs are provided through separate means, then that cost component should be removed from the RVOS calculation.[41] Removal of these costs would result in a net levelized RVOS of $23.94/MWh.

Staff argues that Idaho Power should not rely on the costs of a specific past program to determine the costs of future programs using RVOS-based rates, and instead recommends using the incremental costs of administering net metering or similar programs.[42] OSEIA suggests that Idaho Power use PacifiCorp's administrative costs (about $2.00/MWh) because this would represent the economies of scale for a well-established solar program.[43] CUB and Renewable Northwest (RNW) similarly object to

[37] Order No. 17-357 at 10.

[38] Idaho Power/200, Haener/19-20.

[39] Idaho Power/200, Haener/20.

[40] Idaho Power/100, Haener/15-16. Idaho Power has since updated its inflation rate to reflect the 2.1 percent rate approved in the 2017 IRP. Idaho Power/200, Haener/22.

[41] Idaho Power/200, Haener/20.

[42] Staff/200, Andrus/10.

[43] OSEIA/100, Beach/27.

using Idaho Power's historical data from the Oregon PV Pilot, but did not identify alternative strategies to calculate this administrative cost element.[44]

Idaho Power understands and appreciates parties' concerns, but nonetheless believes that using *actual costs incurred* by the Company to administer solar PV programs, as directed by the Commission, is the most reliable and principled means of evaluating likely administrative costs. Critically, Idaho Power's Oregon service area is significantly different than the service areas of PGE and PacifiCorp, with less than 19,000 customers. While economies of scale might feasibly reduce overall costs for other utilities, lowering the administrative cost component for Idaho Power would impose an additional cost burden on Idaho Power's remaining Oregon customers.

F. Integration

The Commission directed utilities to calculate an integration cost based on acknowledged integration studies.[45] Idaho Power used the solar integration costs from the most recently-approved standard contract rates for QFs, which yields an integration cost of $0.56/MWh.[46] Idaho Power then escalated this annually, beginning in 2018, at 2.2 percent per the E3 workbook methodology. No party objected to the Company's calculation of this element.

G. Market Price Response

The market price response (MPR) seeks to determine the extent to which increased solar generation reduces market prices for energy, and thereby reduces utilities' costs. The Commission directed Staff to coordinate the use of E3's model to create a

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[44] CUB/100, Gehrke/4-5; RNW/100, O'Brien/15-16.

[45] Order No. 17-357 at 14.

[46] Idaho Power/200, Haener/23.

proxy value for this element.[47] Arne Olson of E3 (via correspondence from Staff) recommended that utilities either (1) use market price elasticity (with values of -0.001 to -0.002 per MWh of renewable energy), or (2) complete sequential runs in a production simulation model, such as AURORA, by adding substantial solar generation to determine the effect on market price during each hour.[48]

Idaho Power used the sequential modeling approach based on the AURORA model, measuring the utility's cost impact based on increased solar during daylight hours. However, because Idaho Power sells more energy to the market than it purchases during daylight hours, the result of increased solar penetration was a negative value for the Company.[49] In light of this negative value, Idaho Power also used a market price elasticity value of -0.001/MWh, as suggested by Mr. Olson.

Staff and RNW disagree with Idaho Power's reliance on the Oregon PV Pilot's solar output to assess the MPR element.[50] Staff urges the Company to modify its calculation to account for solar development in other service territories as well as its own.[51] Idaho Power disagrees with this approach, as any impact from regional solar development would offset the cost of energy component (element 1), which is also based on wholesale market prices.[52]

OSEIA suggests that Idaho Power should use PGE's calculation of MPR because it aligns with the benefits calculated in other markets, such as the New England

[47] Order No. 17-357 at 11.

[48] Idaho Power/200, Haener/23-24.

[49] Idaho Power/200, Haener/24.

[50] RNW/100, O'Brien 20-21; Staff/200, Andrus/10-11.

[51] Staff/200, Andrus/11.

[52] Idaho Power/200, Haener/25.

Independent System Operator (ISO).[53] Idaho Power strongly disagrees for two reasons. ***First***, there is no reason to assume that Idaho Power and PGE have equivalent—or even similar—interactions with the market.[54] ***Second***, Idaho Power is not a member of the New England ISO, or any other ISO. Thus, relying on possible values in entirely different market environments is inappropriate to calculate a utility-specific benefit.[55]

Idaho Power continues to support using the AURORA analysis, as well as the price elasticity approach suggested by Mr. Olson.

H. Hedge Value

The hedge value element is the avoided cost of utility hedging activities. Conceptually, solar could provide a hedge against fuel costs, providing a more stable retail rate over time.[56] The Commission directed each utility to use a 5 percent proxy value for this element. Idaho Power used this 5 percent proxy as directed.[57]

OSEIA urges the Commission to apply an alternate hedge value, using a methodology developed by Clean Power Research, commissioned by the Maine Public Utilities Commission.[58] This approach uses gas commodity price forecasts from the Maine Distributed Solar Valuation Study and current U.S. Treasuries as "risk-free" investments. OSEIA then applied Idaho Power's weighted average cost of capital and a proxy resource with a marginal heat rate of 7,500 Btu/kWh, resulting in a hedge value of $20.69 for Idaho Power.

[53] OSEIA/100, Beach/30.

[54] Idaho Power/200, Haener/25.

[55] Idaho Power/200, Haener/25.

[56] Order No. 17-357 at 12.

[57] Idaho Power/200, Haener/26.

[58] OSEIA/100, Beach/33-34.

OSEIA's proposed approach is not appropriate for Idaho Power's Oregon customers, as Idaho Power's system and risk profile is different from that used for the Maine study. Moreover, the natural gas prices shown by OSEIA are substantially higher than those forecasts used by Idaho Power, and suggest that OSEIA's hedging value overstates the avoided fuel cost benefits.[59]

While Idaho Power does not propose revising the hedging value in the RVOS at this time, the 5 percent risk premium assigned by the Commission is not consistent with Idaho Power's Risk Management Policy, which includes a set process to determine when to initiate future power market purchases and sales. Idaho Power thus believes the most likely value of solar on avoided hedging is zero.[60]

I. Environmental Compliance

The environmental compliance element seeks to value the avoided costs of complying with current and anticipated carbon regulations. The Commission directed utilities to calculate a value for this element for informational purposes only, to be used as a placeholder.[61] Specifically, utilities were directed to consider the avoidable costs associated with reducing carbon emissions from the marginal generating unit with carbon regulation assumptions from each utility's most recently approved IRP.

Consistent with Idaho Power's 2015 and 2017 IRPs, Idaho Power used a zero value for avoided environmental compliance costs. Idaho Power currently has no

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[59] Idaho Power/200, Haener/26.

[60] Idaho Power/200, Haener/27.

[61] Order No. 17-357 at 13.

environmental compliance costs, meaning that no costs are avoided through additional solar generation.[62]

Staff urges the Company to revise its analysis in light of the repeal of the Clean Power Plan, and to instead use the carbon-added data from Idaho Power's 2013 IRP to calculate possible costs associated with new carbon regulation.[63] Idaho Power disagrees with Staff's proposal, as modeling speculative legislation does not improve the RVOS model. The 2013 IRP used carbon pricing consistent with legislation being proposed at that time. There is no current pending federal carbon tax legislation on which to base a carbon tax value. Locking in speculative costs into long-term reimbursement rates for a cost that does not exist would unjustly enrich developers at the expense of customers.[64]

OSEIA suggests that all utilities use a single avoided carbon compliance cost because any compliance regime would apply to all Oregon utilities, and suggested that PGE's compliance costs serve as the benchmark.[65] But OSEIA inappropriately assumes that any carbon regulation regime in Oregon would impact all Oregon utilities identically. Idaho Power currently forecasts compliance costs based on proposed Oregon cap-and-invest legislation, which would not impose any avoidable compliance costs until after 2031.

Idaho Power's Oregon customers are not currently impacted by a cost of carbon, and thus Idaho Power continues to urge the Commission to apply a zero value for avoided environmental compliance costs to the RVOS.

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[62] Idaho Power/200, Haener/27-28.

[63] Staff/200, Andrus/13.

[64] Idaho Power/200, Haener/28.

[65] OSEIA/100, Beach/34.

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J. RPS Compliance

This element values the avoided costs of environmental compliance as a result of increased solar penetration. The Commission directed the utilities to include a placeholder value of zero for this element.[66] Because Idaho Power does not have an RPS in Idaho, and because the Company can already meet the Oregon RPS requirement that will begin in 2025 without any additional investment, the Company believes that a zero value is appropriate for this element.[67] No party objected to the Company's use of a zero value.

K. Grid Services

The grid services element seeks to reflect any additional incremental system benefits that additional solar penetration might provide in the future.[68] The Commission directed utilities to assign a placeholder value of zero for this element, which Idaho Power did. No party objected to the Company's use of a zero value.

2. Utility Scale Alternative

In order to provide a reference point for small scale distributed solar, the Commission directed each utility to provide a separate workbook using utility scale solar values.[69] This proxy would remove the cost components for T&D capacity, administration, and line losses, as components not applicable to utility scale solar. The Commission further noted that utilities should explain how the proxy relates to each utility's IRP.[70]

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[66] Order No. 17-357 at 13.

[67] Idaho Power/200, Haener/29.

[68] Idaho Power/200, Haener/29.

[69] Order No. 17-357 at 18.

[70] Order No. 17-357 at 18.

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Idaho Power developed a utility scale proxy by assuming a 30 MW single-axis tracking project. This project is consistent with Idaho Power's 2017 IRP, which contemplated possible utility scale solar projects for potential future development.[71] Per the Commission's direction, Idaho Power removed the T&D capacity, administration, and line losses components from the utility scale RVOS calculation.[72] The calculation yielded a levelized net value of $45.01/MWh.[73]

Staff and OSEIA objected that Idaho Power held all the RVOS values constant while simply removing the T&D capacity, administration, and line losses components.[74] However, Staff suggests that there may be need for further guidance from the Commission to clarify the direction and intent of the utility scale RVOS, and suggests that Idaho Power might revise its approach in the future.[75] Idaho Power agrees with Staff that additional clarification is needed, and intends to update its utility scale RVOS to incorporate any additional guidance from the Commission in the next Phase of the RVOS.

III. CONCLUSION

Idaho Power complied with the Commission's direction to implement each of the elements of the RVOS, using E3's workbook and accompanying guidance. To the extent that the Commission seeks to improve the accuracy of the RVOS, Idaho Power recommends omitting the market price response, hedge value, environmental compliance,

[71] Idaho Power/200, Haener/30.

[72] Idaho Power/200, Haener/31.

[73] Idaho Power/200, Haener/30.

[74] Staff/100, Andrus/56; OSEIA/100, Beach/40.

[75] Staff/100, Andrus/57.

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and RPS compliance elements. Idaho Power looks forward to receiving additional Commission guidance in the next Phase of the RVOS.

Dated this 26th day of July 2018.

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