Docket No. UM 1911

Witness: Michael O’Brien

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1911

RENEWABLE NORTHWEST’S EXHIBIT 100

Opening Testimony of Michael O’Brien

March 16, 2018

INTRODUCTION

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

A. Michael O'Brien, Research Director at Renewable Northwest. My business address is 421 SW 6th Avenue, Suite 975, Portland, OR 97204–1625.

Q. On whose behalf are you testifying?

A. This testimony is on behalf of Renewable Northwest.

Q. Mr. O'Brien, please describe your educational background and work experience.

A. I hold a Ph.D. in Physics from the University of Birmingham, in the United Kingdom, which included an MSc in the Physics and Technology of Nuclear Reactors. I also hold a BSc(Hons) in Physics from the University of Birmingham. After post-doctoral research with the United Kingdom Atomic Energy Authority, I completed an MPhil in Technology Policy at the University of Cambridge. Following Cambridge I worked for the UK Parliamentary Office of Science and Technology as Energy Advisor, and then for the House of Commons Energy and Climate Change Select Committee as Committee Specialist. I have been working at Renewable Northwest since I moved to the United States in June 2012.

Q. What is the purpose of your opening testimony?

A. We appreciate the opportunity to testify to the Oregon Public Utility Commission ("the Commission") in response to Direct Testimonies contained within the Resource Value of Solar Filing ("RVOS") of Idaho Power ("IPCo"), in compliance with Commission Order No. 17-357, filed November 30, 2017.

Q. Would you please summarize your testimony?

A. Yes. First I discuss Idaho Power's RVOS methodology generally and conclude that any estimate of the RVOS that is applied outside of this proceeding should use inputs from the latest acknowledged IRP. Next, I summarize the Commission's direction as well as the utility's methods for determining each element of IPCo's RVOS estimate.

With respect to the elements Energy, Generation Capacity, Administration, and RPS Compliance, I identify concerns that may result in an RVOS estimate that undervalues the RVOS. For Energy, I express concern with IPCo's choice to of system, for modeling purposes, when estimating the value for this element. For Generation Capacity, I reiterate the importance of estimating the value of this element with inputs from the latest acknowledged IRP before the RVOS is applied outside of this proceeding. Similarly, for RPS Compliance, I highlight the importance of determining a methodology and including a value for this element before the RVOS can be useful.

Finally, I show that the RVOS values proposed by IPCo, PacifiCorp, and Portland General Electric ("PGE") are lower than one would expect based on available research.

GENERAL COMMENTS ON IPCO's RVOS ESTIMATE

Q. Did IPCo provide a summary of its RVOS values by element?

A. Yes. A summary of IPCo's RVOS values by element is shown in Table 1.

Element	Value Standard Size Project ($/MWh Real Levelized)	Value Utility Scale Size Project ($/MWh Real Levelized)
1. Energy	29.74	29.74
2. Generation Capacity	15.30	14.34
3. T&D Capacity	0.87	-
4. Line Losses	2.54	-
5. Administration	(47.77)	-
6. Integration	(0.56)	(0.56)
7. Market Price Response	0.00	0.00
8. Hedge Value	1.49	1.49
9. Environmental Compliance	0.00	0.00
10. RPS Compliance	0.00	0.00
11. Grid Services	0.00	0.00
Net Levelized RVOS	**1.61**	**45.01**

Table 1—IPCo's RVOS Values by Element.[1]

Q. How did IPCo describe its calculation of the RVOS value based on Commission Order 17-357?

A. IPCo stated that the Commission directed the utilities to develop as a "25 year marginal, levelized value for a generic, small-scale solar resource installed in 2017."[2]

Q. What was the standard size project that IPCo used for a "small-scale solar resource installed in 2017"?

A. IPCo used a standard size project of 0.41 MW, or 410 kW.[3] That is almost 70—80 times the size of a typical 5-6 kW solar rooftop system.

[1] Idaho Power/100 Haener/4.
[2] UM 1716, Order 17-357 at 1 (Sep. 15 2017).
[3] Idaho Power/100 Haener/3.
[4] Idaho Power/100 Haener/4; UM 1910, PAC/100 MacNeil/3; UM 1912 PGE/100 Goodspeed/7.
[5] Idaho Power/100 Haener/15.
[6] UM 1716, Order 17-357 at 1 (Sep. 15 2017).
Order No. 17-357 at 15.
[7] *Id*. at 21.
[8] *Id*.
[9] *Id*.
[10] Idaho Power/100 Haener/5.
[11] *Id*. at 4.

Q. Do you have any concerns regarding the inputs that IPCo used for the RVOS estimates in its testimony?

A. Yes. The Company used several inputs from its 2015 IRP for its RVOS calculation. IPCo's use of 2015 IRP inputs is understandable because the Company's 2017 IRP had not been acknowledged as of November 30, 2017, when the Company filed testimony in this docket. However, any RVOS estimate that may applied outside of this docket, e.g. to determine the bill credit rate for community solar, should rely on inputs from IPCo's latest acknowledged IRP. By the time that the RVOS is first applied, it will likely no longer appropriate for IPCo's estimate of the RVOS to rely on 2015 IRP inputs.

Q. How do IPCo's RVOS values by element compare to those estimated by PacifiCorp (UM 1910) and PGE (UM 1911)?

A. Figure 1 shows the RVOS values by element for PGE, PacifiCorp and IPCo.

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[3] Idaho Power/100 Haener/3.

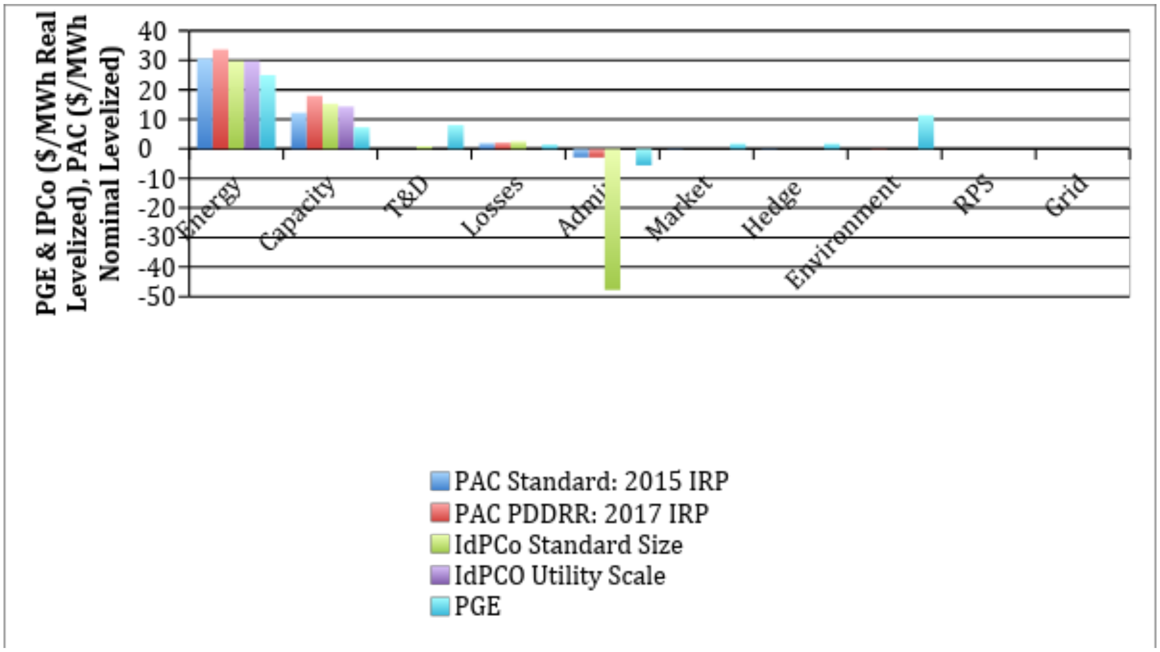

Figure 1—RVOS Values by Element for PGE, PAC, and IPCo.[4]

Q. Did IPCo state its understanding of how the RVOS will be used?

A. Yes. IPCo said it understood "that the RVOS will be used for compensation for participants in the Oregon Solar Photovoltaic Pilot Program when the existing projects seek renewable contracts."[5]

Q. Do you agree with IPCo's statement on how the RVOS will be used?

A. No. Whilethe RVOS could ultimately inform the compensation of participants in the Oregon Solar Photovoltaic Pilot Program, in Order No. 17-357 the Commission stated that it"ha[d] not prejudged any applications [of the RVOS]."[6]

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[4] Idaho Power/100 Haener/4; UM 1910, PAC/100 MacNeil/3; UM 1912 PGE/100 Goodspeed/7.
[5] Idaho Power/100 Haener/15.
[6] Order No. 17-357 at 16.

ELEMENT 1—ENERGY

Q. How did Commission Order No. 17-357 define Element 1—Energy?

A. The Commission defined Energy as "[t]he marginal avoided cost of procuring or producing energy, including fuel, O&M, pipeline costs and all other variable costs."[7]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 1—Energy?

A. The Commission required the utilities to "produce a 12 x 24 block for energy prices and include a detailed explanation of how they created the block."[8] The Commission also asked utilities to "demonstrate through statistical analysis that their energy values are scaled to represent the average price under a range of hydro conditions."[9]

Q. How did IPCo model solar to determine a 25 year marginal, levelized value for Element 1—Energy for a generic, small-scale solar resource installed in 2017?

A. IPCo stated that it used "actual 2011–2016 hourly solar energy shapes collected from Idaho Power's participants in the Solar Photovoltaic Pilot Program, Oregon Schedule 88…. [which] includes 54 fixed plate solar projects with a cumulative generation capacity of 0.41 MW."[10] IPCo modeled a new system installed in 2017 as a participant of the Solar Photovoltaic Pilot Program, also known as the Volumetric Incentive Rate ("VIR"), which is no longer open to new participants.

[7] *Id*. at 21.
[8] *Id*.
[9] *Id*.
[10] Idaho Power/100 Haener/5.

Q. Do you have any concerns with IPCo's reliance on the VIR in estimating the value for Element 1—Energy?

A. Yes. IPCo's decision to model a new system installed in 2017 as a participant of the VIR appears unreasonable as the program is no longer open to new participants.

Q. How did IPCo's value for Element 1—Energy compare with the value calculated by PacifiCorp and PGE?

A. IPCo calculated a real levelized value for standard size and utility scale size projects of 29.74 $/MWh.[11] PGE calculated a real levelized value for Element 1—Energy of 24.98 $(2017)/MWh.[12] PacifiCorp calculated a nominal levelized (2018-2042) value of 30.58 $/MWh using the standard methodology, and 33.63 $/MWh using the PDDRR methodology .[13]

Q. Do you have anything else to say about IPCo's value for Element 1—Energy.

A. Not at this time.

[11] *Id*. at 4.
[12] UM 1912, PGE/100 Goodspeed/7.
[13] UM 1910, PAC/100 MacNeil/3.

ELEMENT 2—GENERATION CAPACITY

Q. How did Commission Order No. 17-357 define Element 2—Generation Capacity?

A. The Commission defined Generation Capacity as "[t]he marginal avoided cost of building and maintain the lowest net cost generation capacity resource."[14]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 2—Generation Capacity?

A. The Commission required the utilities to "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."[15]

Q. What were the next steps for Element 2—Generation Capacity outlined in Commission Order No. 17-357?

A. In addition to requiring the utilities to propose values for Generation Capacity in this phase of the proceeding, the Commission directed Staff to "convene a workshop to explore options for valuing capacity additions incrementally."[16]

[14] Order No. 17-357 at 21.
[15] *Id*.
[16] *Id*.

Q. In ordering the utilities to calculate Element 2—Generation Capacity, the Commission directed utilities to use the "last acknowledged IRP resource-balance year, and then remove new incremental expected distributed solar from that forecast, and then if applicable, provide an adjusted deficiency date."[17] Did IPCo follow this order?

A. No. IPCo stated that the load forecast used 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 for the 2015 IRP."[18]

Q. Do you have any concerns with IPCo's value for Element 2—Generation Capacity?

A. Yes. As I mentioned in my introduction, IPCo appears to use 2015 IRP inputs to calculate the value of this and other elements of the RVOS. I understand the Company's decision to do so given the timeline for acknowledgement for its 2017 IRP. However, an RVOS estimate should reflect the latest acknowledged IRP before being applied to any program outside of this proceeding or before informing any policy decisions.

Q. How did IPCo's value for Element 2—Generation Capacity compare with the value calculated by PacifiCorp and PGE?

A. IPCo calculated a real levelized value for standard size of 15.30 $/MWh and 14. 34 $/MWh for utility scale size projects.[19] PGE calculated a real levelized value for Element 2—Generation Capacity of 7.30 $(2017)/MWh.[20] PacifiCorp

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[17] UM 1716, Order No. 17-357 at 8
[18] Idaho Power/100 Haener/8.
[19] Idaho Power/100 Haener/4.
[20] UM 1912, PGE/100 Goodspeed/7.

calculated a nominal levelized (2018-2042) value of 12.20 $/MWh using the standard methodology, and 17.96 $/MWh using the PDDRR methodology .[21]

Q. Do you have anything else to say about IPCo's value for Element 2—Generation Capacity.

A. Not at this time.

[21] UM 1910, PAC/100 MacNeil/3.

ELEMENT 3—TRANSMISSION AND DISTRIBUTION CAPACITY

Q. How did Commission Order No. 17-357 define Element 3—Transmission And Distribution Capacity?

A. The Commission defined Transmission and Distribution Capacity as "[a]voided or deferred cost of expanding, replacing, or upgrading transmission and distribution (T&D) infrastructure."[22]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 3—T&D Capacity?

A. The Commission required the utilities to "develop a system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration in Oregon service areas."[23]

Q. What values did IPCo determine for avoided transmission and distribution costs?

A. IPCo's RVOS calculation includes "a system-wide average of $3.76/kW-year for the avoided T&D infrastructure cost. The $3.76/kW-year was divided evenly between the Transmission Deferral Value and the Distribution Deferral Value [...] resulting in $1.88/kW-year for each input."[24]

[22] Order No. 17-357 at 21.
[23] *Id*.
[24] Idaho Power/100 Haener/8.

Q. How did IPCo's value for Element 3—T&D Capacity compare with the value calculated by PacifiCorp and PGE?

A. IPCo calculated a real levelized value for standard size of 0.87 $/MWh and 0.00 $/MWh for utility scale size projects.[25] PGE calculated a real levelized value for Element 3—T&D Capacity of 8.08 $(2017)/MWh.[26] PacifiCorp calculated a nominal levelized (2018-2042) value of 0.08 $/MWh using the standard methodology and the PDDRR methodology.[27]

Q. Do you have anything else to say about IPCo's value for Element 3—T&D Capacity.

A. Not at this time.

[25] Idaho Power/100 Haener/4.
[26] UM 1912, PGE/100 Goodspeed/7.
[27] UM 1910, PAC/100 MacNeil/3.

ELEMENT 4—LINE LOSSES

Q. How did Commission Order No. 17-357 define Element 4—Line Losses?

A. The Commission defined Line Losses as "[a]voided marginal electricity losses."[28]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 4—Line Losses?

A. The Commission required utilities to "develop hourly averages of avoided marginal line losses attributable to increased penetration of solar PV systems in Oregon service areas."[29] The Commission also asked that "incremental line loss estimates … reflect the hours solar PV systems are generating electricity."[30]

Q. What was IPCo's estimates of avoided marginal lines losses?

A. IPCo estimated incremental avoided marginal line losses to be in the range 8.5—8.7%.[31]

Q. How did IPCo's value for Element 4—Line Losses compare with the value calculated by PacifiCorp and PGE?

A. IPCo calculated a real levelized value for standard size of 2.54$/MWh and 0.00 $/MWh for utility scale size projects.[32] PGE calculated a real levelized value for Element 4—Line Losses of 1.48 $(2017)/MWh.[33] PacifiCorp calculated a nominal levelized (2018-2042) value of 1.96 $/MWh using the standard methodology and 2.14 $/MWh using the PDDRR methodology.[34]

[28] Order No. 17-357 at 22.
[29] *Id*.
[30] *Id*.
[31] Idaho Power/100 Haener/14.
[32] *Id*. at 4.
[33] UM 1912, PGE/100 Goodspeed/7.
[34] UM 1910, PAC/100 MacNeil/3.

Q. Do you have anything else to say about IPCo's value for Element 4—Line Losses.

A. Not at this time.

ELEMENT 5—ADMINISTRATION

Q. How did Commission Order No. 17-357 define Element 5—Administration?

A. The Commission defined Administration as "[i]ncreased utility costs of administering solar PV programs."[35]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 5—Administration?

A. The Commission required the utilities to "develop estimates of the direct, incremental costs of administering solar PV programs including staff, software, incremental distribution investments, and other utility costs."[36]

Q. Did Order 17-357 provide any further detail on how Element 5—Administration should be determined?

A. Yes. The Order adds that "[a] dministration 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."[37]

Q. How did IPCo model solar to determine a 25 year marginal, levelized value for Element 5—Administration for a generic, small-scale solar resource installed in 2017?

A. IPCo stated that it determined a value for Element 5—Administration "by reviewing the actual costs incurred for the Oregon Solar Photovoltaic Pilot Program in 2016. The Company's estimate of administering solar PV programs is $47.77 per MWh, escalated at the 2015 IRP inflation rate of 2.2 percent annually.

[35] Order No. 17-357 at 22.
[36] *Id*.
[37] *Id*. at 10.

The $47.77 per MWh cost is based on 2016 actual expenses for the Oregon Solar Photovoltaic Pilot Program, including $14,065 in labor costs, $23,899 in communication service fees, and $638 in other operational expenses, totaling $38,601 in costs, divided by the 808 MWh of generation from the program for 2016. It is Idaho Power's understanding that the RVOS will be used for compensation for participants in the Oregon Solar Photovoltaic Pilot Program when the existing projects seek renewable contracts."[38]

Q. Does IPCo's use of the Oregon Solar Photovoltaic Program Pilot administration costs make sense in the context of UM 1911?

A. No. The legislation to that led to the Oregon Solar Photovoltaic Program Pilot passed in 2009.[39] Under ORS 757.365(4), "[a] retail electricity consumer participating in a pilot program may receive payments based on electricity generated from solar photovoltaic energy system output for <u>15 years</u> from the consumer's date of enrollment in the program, at rates or through a rate formula in a tariff schedule established at the time of enrollment, or at rates otherwise established at the time of enrollment. The consumer thereafter may receive payments based upon electricity generated from the qualifying system at a rate equal to the resource value."[40] It is my understanding that this means that the earliest year a participant would be eligible for compensation "at a rate equal to the resource value" is 2009 plus 15 years, which comes to 2024. It is therefore not clear why IPCo considers the Oregon Solar Photovoltaic Program Pilot when

[38] Idaho Power/100 Haener/15.
[39] *See* Idaho Power, "Oregon Solar Photovoltaic Pilot Program," at 1 (*available at* https://testipco.idahopower.com/pdfs/AboutUs/businessToBusiness/CapacityReservationApplicationProcess.pdf).
[40] ORS 757.365(4) (emphasis added).

trying to determine the 25-year marginal, levelized value for Element 5—Administration for a generic, small-scale solar resource installed in 2017.

Q. Did IPCo have any observations about their value for Element 5—Administration?

A. Yes. IPCo "recognize[d] that the administration component is relatively large and may be driving down the RVOS calculation."[41]

Q. How did IPCo's value for Element 5—Administration compare with the value calculated by PacifiCorp and IPCo?

A. IPCo calculated a real levelized value for standard size of -47.77$/MWh and 0.00 $/MWh for utility scale size projects.[42] PGE calculated a real levelized value for Element 5—Administration of -5.58 $(2017)/MWh.[43] PacifiCorp calculated a nominal levelized (2018-2042) value of -2.88 $/MWh using the standard methodology and the PDDRR methodology.[44]

Q. Do you have anything else to say about IPCo's value for Element 5—Administration

A. Not at this time.

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[41] Idaho Power/100 Haener/16.
[42] *Id*. at 4.
[43] UM 1912, PGE/100 Goodspeed/7.
[44] UM 1910, PAC/100 MacNeil/3.

ELEMENT 6—INTEGRATION

Q. How did Commission Order No. 17-357 define Element 6—Integration?

A. The Commission defined Integration as "[t]he costs of a utility holding additional reserves in order to accommodate unforeseen fluctuations in system net loads due to addition of renewable resources."[45]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 6—Integration?

A. The Commission required utilities to "make estimates of integration costs based on acknowledged integration studies."[46]

Q. What integration costs did IPCo use to determine Element 6—Integration?

A. IPCo "used the current Commission-approved solar integration costs included in the development of the Company's Standard Contract Rates." [47] IPCo added that "[t]he RVOS 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 methodology".

Q. How did IPCo's value for Element 6—Integration compare with the value calculated by PacifiCorp and PGE?

A. IPCo calculated a real levelized value of -0.56$/MWh for standard size and utility scale size projects.[48] PGE calculated a real levelized value for Element 6—Integration of -0.83$(2017)/MWh.[49] PacifiCorp calculated a nominal levelized

[45] Order No. 17-357 at 22.
[46] *Id*.
[47] Idaho Power/100 Haener/17.
[48] *Id*. at 4.
[49] UM 1912, PGE/100 Goodspeed/7.

(2018-2042) value of -0.82 \$/MWh using the standard methodology and the PDDRR methodology .[50]

Q. Do you have anything else to say about IPCo's value for Element 6—Integration?

A. Not at this time.

[50] UM 1910, PAC/100 MacNeil/3.

ELEMENT 7—MARKET PRICE RESPONSE

Q. How did Commission Order No. 17-357 define Element 7—Market Price Response?

A. The Commission defined Market Price Response as "[t]he change in utility costs due to lower wholesale energy market prices caused by increased solar PV production."[51]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 7—Market Price Response?

A. The Commission ordered 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."[52]

Q. Did Staff facilitate use of E3's model to create a proxy value for market price response?

A. Yes. Staff (Mark Bassett) reached out to E3 (Arne Olsen) and asked if "[…] the $3 per MWh sample proxy value found in the E3 model is accurate[?]"[53] E3 replied:

> "The $3/MWh is a made-up number just put in as an example and shouldn't be used as a proxy.
>
> There are two ways that a better number could be calculated:
>
> 1. I've been involved in several studies of the impact of wind & solar generation on market prices in the West. See the attached papers. There are others out there as well. The papers estimate a market price elasticity of -0.001 to -0.002 for each MWh

[51] Order No. 17-357 at 22.
[52] *Id*.
[53] Staff (Mark Bassett) email to RVOS Stakeholders, November 7, 2017.

> of renewable energy. The elasticity is measured separately for Heavy Load Hours and Light Load Hours.
>
> 2. The utilities could do sequential runs in a production simulation model, e.g., Aurora, with a significant enough increment of solar added to affect the calculated market price during each hour. The price differences could be used to derive a market price elasticity per MWh of energy produced from customer owned solar resources. This would have the advantage that it could be used to derive granular values for various time periods, however real markets often behave differently from what production simulation models would imply."
>
> In either case, as you noted, the change in market price would be multiplied by the utility's net short or long position during each hour, so this would be a benefit if the utility is short and a cost if the utility is long."

Q. How did IPCo determine a value for Element 7—Market Price Response?

A. IPCo "evaluated AURORA output to determine the hourly imports and exports from the Idaho Power system."[54] IPCo added that "[t]he 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."[55]

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[54] Idaho Power/100 Haener/18.
[55] *Id*. at 19.

Q. What market price elasticity did IPCo use?

A. IPCo used " a market price elasticity of -0.001 per MWh for the market price response component to the RVOS as suggested by Mr. Olson."[56]

Q. What was IPCo's view of the impact of solar on Element 7—Market Price Response?

A. IPCo stated that it "does not envision its Oregon Solar Photovoltaic Pilot Program, currently consisting of 54 projects with a cumulative generation capacity of 0.41 MW, as significant enough to influence market prices. As such, Idaho Power does not see value in utilizing either of these methods for determining a proxy value for market price response, nor does it see value in including this component in the RVOS calculation at this time."

Q. Was IPCo's reliance on VIR when determining that Market Price Response was zero appropriate?

A. No. Even if IPCo is correct in its assessment of how the 0.41 MW are not significant enough to influence market prices, its reliance on VIR to value Market Price Response at zero is not appropriate.

Q. How did IPCo's value for Element 7—Market Price Response compare with the value calculated by PacifiCorp and PGE?

A. IPCo calculated a real levelized value of 0.00$/MWh for standard size and utility scale size projects.[57] PGE calculated a real levelized value for Element 7—Market Price Response of 1.81$(2017)/MWh.[58] PacifiCorp calculated a nominal levelized

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[56] *Id*.
[57] *Id*. at 4.
[58] UM 1912, PGE/100 Goodspeed/7.

(2018-2042) value of 0.15 \$/MWh using the standard methodology and 0.00 \$/MWh using the PDDRR methodology .[59]

Q. Do you have anything else to say about PGE's value for Element 7—Market Price Response?

A. Not at this time.

ELEMENT 8—HEDGE VALUE

Q. How did Commission Order No. 17-357 define Element 8—Hedge Value?

A. The Commission defined Hedge Value as the "[a]voided cost of utility hedging activities, *i.e.*, transactions intended solely to provide a more stable retail rate over time."[60]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 8—Hedge Value?

A. The Commission required the utilities "to assign a proxy value of 5 percent of energy."[61]

Q. What was IPCo's view of the 5 percent of energy proxy value that Order 17-537 required utilities to use?

A. IPCo stated that "[t]he 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 would recommend using a value of zero for the avoided hedge value."[62]

[59] UM 1910, PAC/100 MacNeil/3.
[60] Order No. 17-357 at 22.
[61] *Id*.
[62] Idaho Power/100 Haener/20.

Q. How did IPCo's value for Element 8—Hedge Value compare with the value calculated by PacifiCorp and PGE?

A. IPCo calculated a real levelized value of 1.49 $/MWh for standard size and utility scale size projects.[63] PGE calculated a real levelized value for Element 8—Hedge Value of 1.25 $(2017)/MWh.[64] PacifiCorp calculated a nominal levelized (2018-2042) value of 1.54 $/MWh using the standard methodology and 1.68 $/MWh using the PDDRR methodology.[65]

Q. Do you have anything else to say about IPCo's value for Element 8—Hedge Value?

A. Not at this time.

[63] *Id*. at 4.
[64] UM 1912, PGE/100 Goodspeed/7.
[65] UM 1910, PAC/100 MacNeil/3.

ELEMENT 9—ENVIRONMENTAL COMPLIANCE

Q. How did Commission Order No. 17-357 define Element 9—Environmental Compliance?

A. The Commission defined Environmental Compliance as the "[a]voided cost of complying with existing and anticipated environmental standards."[66]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 9—Environmental Compliance?

A. The Commission required the utilities to "estimate the avoided cost based on a reduction in carbon emissions from the marginal generating unit."[67] The Commission also asked utilities to "value future anticipated standards utilities should use the carbon regulation assumptions from their IRP."[68]

Q. What was IPCo's perspective on Element 9—Environmental Compliance?

A. IPCo stated that it "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 IRP."[69]

Q. How did IPCo's value for Element 9—Environmental Compliance compare with the value calculated by PacifiCorp and IPCo?

A. IPCo calculated a real levelized value of 0.00 $/MWh for standard size and utility scale size projects.[70] PGE calculated a real levelized value for Element 9—

[66] Order No. 17-357 at 23.
[67] *Id*.
[68] *Id*.
[69] Idaho Power/100 Haener/21.
[70] *Id*. at 4.

Environmental Compliance of 11.41 $(2017)/MWh.[71] PacifiCorp calculated a nominal levelized (2018-2042) value of 0.11 $/MWh using the standard methodology and 0.22 $/MWh using the PDDRR methodology.[72]

Q. Do you have anything else to say about IPCO's value for Element 9—Environmental Compliance?

A. Not at this time.

[71] UM 1912, PGE/100 Goodspeed/7.
[72] UM 1910, PAC/100 MacNeil/3.

ELEMENT 10—RPS COMPLIANCE

Q. How did Commission Order No. 17-357 define Element 10—RPS Compliance?

A. The Commission did not offer a definition of RPS Compliance, but instead said a definition was "[t]o be determined."[73]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 10—RPS Compliance?

A. The Commission required the utilities to "use a value of zero in their initial Phase II filings."[74]

Q. Do you have any concerns regarding the current lack of a value for Element 10—RPS Compliance?

A. Yes. I am concerned about any potential application of an RVOS estimate that does not include a value for the element RPS Compliance. RPS Compliance was an element widely discussed during UM 1716. Mr. Arne Olson, who developed this RVOS methodology and testified in UM 1716 on behalf of Staff, indicated that a solar system provides an RPS Compliance value "if it reduces the utility's retail sales, e.g. through net energy metering."[75]

The Commission did not adopt a definition of RPS Compliance in Order 17-357, instead signaling its intention to assign a methodology to that element before the end of this phase of the proceeding.[76]

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[73] Order No. 17-357 at 23.
[74] *Id*.
[75] UM 1716, Staff/400 Olson/13.
[76] Order 17-357 at 2.

I want to underscore how important it is for the Commission to make that determination and for utilities to assign a value to RPS Compliance before an RVOS estimate is applied to other programs and before an RVOS estimate is useful to inform any policy considerations.

Q. Do you have anything else to say about IPCo's value for Element 10—RPS Compliance?

A. Not at this time.

ELEMENT 11—GRID SERVICES

Q. How did Commission Order No. 17-357 define Element 11—Grid Services?

A. The Commission defined Grid Services as "[t]he potential benefits of solar PV in advanced, uncommon applications and from utilities' increasing ability to capture the benefits of mass-market smart inverters."[77]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 11—Grid Services?

A. The Commission required the utilities to "use a value of zero for this element."[78]

Q. Do you have anything else to say about IPCo's value for Element 11—Grid Services?

A. Not at this time.

[77] Order No. 17-357 at 23.
[78] *Id*.

CONCLUSION

Q. Do you have any concluding thoughts on IPCo's RVOS proposal?

A. Yes. IPCo bases its estimated RVOS on values for each element that appear to generally be significantly lower than one would expect based on existing research, resulting in what may be a depressed RVOS estimate. For example, Figure 2 compares the values of each RVOS element used by IPCo (as well as PacifiCorp and PGE) to the values of the same elements according to a meta-analysis performed by the Rocky Mountain Institute in 2013.[79] As a result, even where I have not noted specific disagreement with IPCo's methodology, I retain some skepticism and respectfully suggest that the Commission take a hard look at IPCo's proposal before approving a final RVOS estimate.

[79] Rocky Mountain Institute, "A Review of Solar PV Cost and Benefit Studies, 2nd Edition" (Sept. 2013), available at https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_eLab-DER-Benefit-Cost-Deck_2nd_Edition131015.pdf. The values included in Figure 2 above were derived from the range of values included in the Rocky Mountain Institute report for each element of the RVOS calculation.

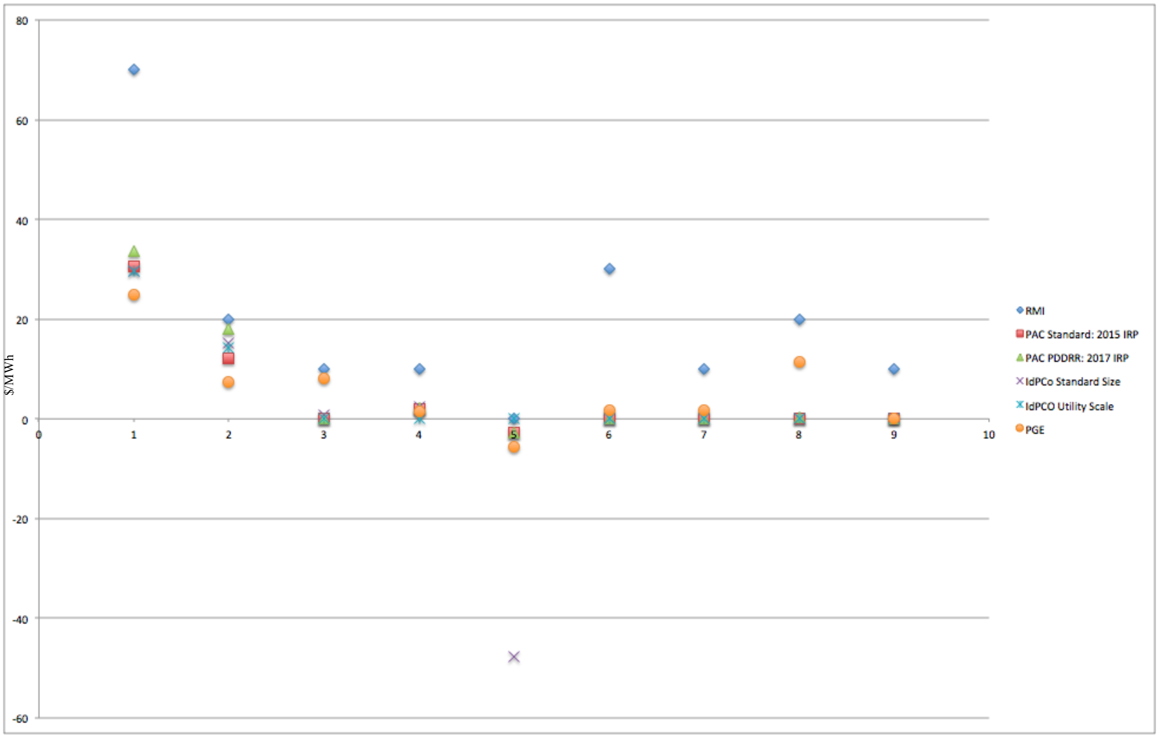

Figure 2: Comparison of PacifiCorp, PGE's and IPCo's values with values derived from RMI study

The following elements are represented in the x axis: 1) Energy, 2) Capacity, 3) T&D, 4) Losses, 5) Administration, 5) Market Price Response, 7) Hedge Value, 8) Environmental Compliance, 9) Grid Services