Docket No. UM 1912

Witness: Michael O'Brien

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1912

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 December 4, 2017 Resource Value of Solar ("RVOS") Filing of Portland General Electric ("PGE), in compliance with Commission Order No. 17-357.

Q. Would you please summarize your testimony?

A. Yes. First, I highlight that the Commission embarked on its investigation of the RVOS without prejudging the potential applications for the RVOS. I then summarize the Commission's direction as well as the utility's methods for determining each element of PGE's RVOS estimate.

With respect to the elements Generation Capacity and RPS Compliance, I identify concerns that may result in an RVOS estimate that undervalues the RVOS. For Generation Capacity, I express concern with PGE's decision to use a capacity value of zero during its sufficiency period. I also express concern with what appears like PGE's failure to adjust its deficiency date to remove new incremental expected distributed solar. For RPS Compliance, I highlight the importance of determining a methodology and including a value for this element before the RVOS is applied outside of this proceeding or used to inform policy decisions.

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 PGE'S RVOS ESTIMATE

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

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

RVOS Element	2017 $/MWh, real levelized value
Energy	24.98
Generation Capacity	7.30
T&D Capacity	8.08
Line Loss	1.48
Administration	(5.58)
Market Price Response	1.81
Integration	(0.83)
Hedge Value	1.25
Environmental Compliance	11.41
RPS Compliance	0
Grid Services	0
RVOS Total	**49.88**

*totals may not tie due to rounding

Table 1—PGE's RVOS values by Element[1]

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

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

[1] PGE/100 Goodspeed/7.

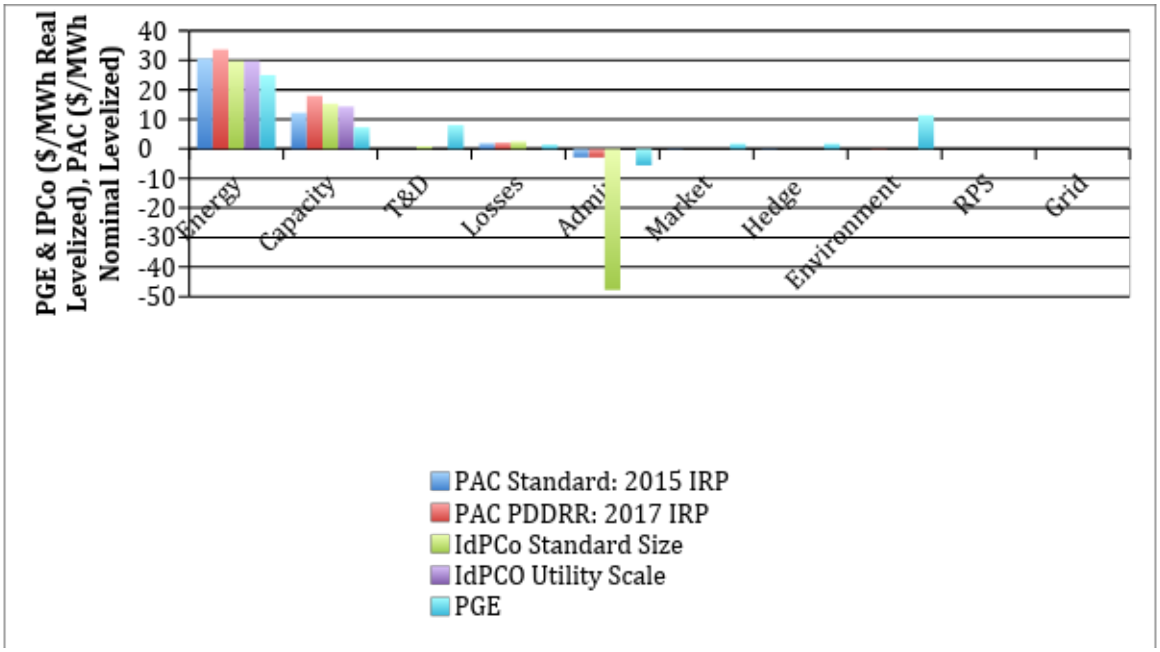

Figure 1—RVOS Values by Element for PGE, PAC, and IPCo.[2]

Q. Did PGE state there was a specific indication of how the RVOS will be used ?

A. Yes. PGE stated that, “[a] specific application for the RVOS has been identified for community solar and was specified in the 2016 legislation, SB 1547. Additionally, in Docket No. UM 1758 ‘Solar Incentives Report’ from the Commission to the Oregon Legislature, the Commission stated that the RVOS ‘should also be used for net metering….[sic] We will open a docket on examining the integration of the RVOS for net metering.’”[3]

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

A. No. While I understand that the RVOS could inform the valuation of community solar projects, Order No. 17-357 states that the Commission “ha[d] not prejudged any applications.”[4]

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2 PGE/100 Goodspeed/7; UM 1910, PAC/100 Macneil/3; UM 1911 Idaho Power/100 Haener/4.
3 PGE/100 Goodspeed/2.
4 UM 1716, Order No. 17-357 at 16 (Sep. 15, 2017).

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."[5]

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. Utilities shall demonstrate through statistical analysis that their energy values are scaled to represent the average price under a range of hydro conditions."[6]

Q. How did PGE calculate Element 1—Energy?

A. PGE stated that it calculated the avoided costs of energy "based on forecasted wholesale market prices. These prices are based on the same inputs used for the monthly wholesale market prices during the resource sufficiency period in PGE's Schedule 201."[7]

To create the daily profiles, "PGE used the hourly price output for the year 2024 from the same Aurora model run used for Schedule 201. Daily shape factor profiles were calculated for each month based on the hourly prices."[8]

[5] *Id*. at 21.
[6] *Id*.
[7] PGE/200 Jordan/7.
[8] *Id*.

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

A. PGE calculated a real levelized value for Element 1—Energy of 24.98 $(2017)/MWh.[9] IPCo calculated a real levelized value for standard size and utility scale size projects of 29.74 $/MWh.[10] PacifiCorp calculated a nominal levelized (2018-2042) value of 30.58 $/MWh using the standard methodology, and 33.63 $/MWh using the PDDRR methodology .[11]

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

A. Not at this time.

[9] PGE/100 Goodspeed/7.
[10] UM 1911, Idaho Power/100 Haener/4.
[11] 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 maintaining the lowest net cost generation capacity resource."[12]

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." The Commission elaborated: "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."[13]

Q. What sufficiency/deficiency demarcations did PGE use to determine the value of Element 2—Generation Capacity?

A. PGE "advocate[d] for keeping sufficiency and deficiency demarcations in the resource value of solar price consistent with PGE's Schedule 201."[14]

Q. How did PGE use the sufficiency period to determine the value of Element 2—Generation Capacity?

A: PGE assigned no value to capacity during he sufficiency period.[15]

[12] Order No. 17-357 at 21.
[13] *Id*.
[14] PGE/200 Jordan/3.
[15] *Id*.

Q. Do you agree with PGE's decision to assign no value to capacity during the sufficiency period?

A. No. As I testified in UM 1716, a capacity value of zero "would undervalue the RVOS during the sufficiency period because solar systems provide a 'Generation Capacity' benefit even in years when they may not help displace the procurement of a capacity resource."[16]

Q. What did PGE use as a proxy resource when determining the value of Element 2—Generation Capacity?

A. PGE "use[d] a simple cycle combustion turbine (SCCT) as the proxy resource [...] $125.86/kW-year in 2020 dollars, with an in-service year of 2021."[17]

Q. How did PGE use the proxy resource to determine the value of Element 2—Generation Capacity during the deficiency period?

A: PGE stated: " In Schedule 201, during the deficiency period, the capacity contribution of solar resources (per the IRP) is multiplied by the cost of PGE's avoided proxy resource. The resulting value is then spread across the number of peak hours per year, adjusted for the proxy solar resource's peak capacity factor. No capacity payment is assigned to non-peak hours. The model produces one capacity payment (in dollars per MWh) per year for all peak hours (with no seasonal shaping). Peak hours are Monday through Saturday, 6 am—10 pm."[18]

[16] UM 1716, RNW/100 O'Brien/7.
[17] PGE/200 Jordan/3.
[18] *Id*. at 4.

Q. What Effective Load Carrying Capability ("ELCC") did PGE use to determine the value of Element 2—Generation Capacity?

A. PGE stated that "[t]he current Schedule 201 solar ELCC value of 15.33% corresponds to the incremental solar resource bin 200-300 MW. This accounts for solar resources on PGE's system and for executed solar QF contracts."[19] This value correlates with the solar marginal ELCC values presented in PGE's 2016 IRP and shown in Figure 2.

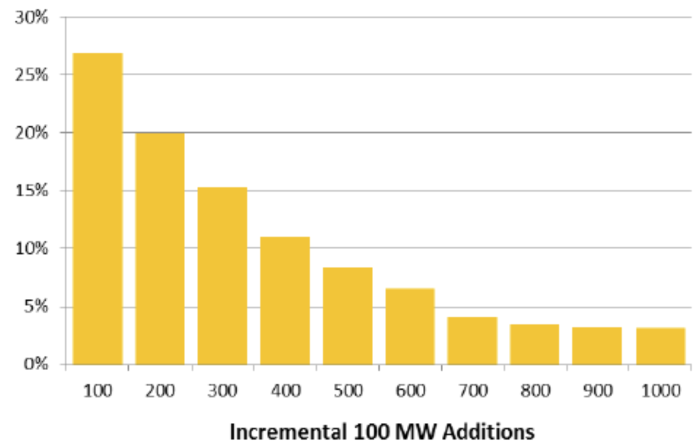

Figure 2—Solar Marginal ELCC (Single-Axis Tracking, Central OR).[20]

Q. Did PGE explain how the calculation of the value of Element 2—Generation Capacity was different from PURPA capacity payments?

A. Yes. PGE stated that "[t]he dollars per MWh number in RVOS differs from the Schedule 201 capacity payment for solar resources in that it applies a (lower) flat payment to be applied over. PGE's standard avoided cost methodology assigns capacity payments to on-peak hours only. The E3 model provided in Staff/100 is constructed with an hourly (8760) and annual framework, resulting in a flat

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[19] *Id*. at 5.
[20] LC 66, PGE 2016 IRP at 127, Figure 5–11.

capacity payment rather than the 12 x 2 format currently used for standard avoided cost."[21]

Q. Did PGE have any recommendations for how Element 2—Generation Capacity should be calculated in the future?

A. Yes. PGE recommends "that solar capacity pricing be calculated as 12x16 peak blocks that incorporated both the seasonal and hourly generation profile of solar and the seasonal and hourly profile of capacity need."[22]

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."[23] Did PGE follow this order?

A. PGE does not seem to have done so. PGE states that it "does not make any explicit assumptions about incremental distributed solar photovoltaic (PV) as part of the load forecasting process. The impact of existing distributed solar is included in PGE's historical energy deliveries data and as such is embedded within PGE's regression based load forecast."[24]

[21] PGE/200 Jordan/5.
[22] PGE/200 Jordan/6.
[23] Order No. 17-357 at 8.
[24] PGE/200 Jordan/6.

Q. What is the effect, if any, of not removing new incremental expected distributed solar from the forecast on PGE's end value for Element 2—Generation Capacity?

A. By not removing incremental expected distributed solar from its forecast, PGE may have failed to capture the capacity value of expected distributed solar resources in its valuation of Element 2—Generation Capacity. PGE may also have underestimated its capacity need and, therefore, the capacity value of new solar generation above and beyond expected distributed solar. Altogether, PGE's methodology regarding incremental expected distributed solar likely dampened its value for Element 2—Generation Capacity.

There are additional negative downstream effects from an inaccurate accounting of distributed solar generation. As I testified in Commission Docket UM 1716: "[I]f the utility anticipates increased behind-the-meter solar adoption in its IRP load forecast (i.e. the utility reduces its load forecast owing to increased customer self-generation), this could result in the utility's resource sufficiency year being pushed out. A later resource deficiency year would result in reduced capacity value for solar, and therefore a lower RVOS; this, in turn, could result in lower adoption of solar, which could lead to the utility becoming deficient earlier."[25]

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

A. PGE calculated a real levelized value for Element 2—Generation Capacity of 7.30 $(2017)/MWh.[26] IPCo calculated a real levelized value for standard size of 15.30

[25] UM 1716, RNW/100 O'Brien/6.
[26] PGE/100 Goodspeed/7.

$/MWh and 14. 34 $/MWh for utility scale size projects.[27] PacifiCorp calculated a nominal levelized (2018-2042) value of 12.20 $/MWh using the standard methodology, and 17.96 $/MWh using the PDDRR methodology .[28]

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

A. Not at this time.

[27] UM 1911, Idaho Power/100 Haener/4.
[28] 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 the "Avoided or deferred cost of expanding, replacing, or upgrading transmission and distribution (T&D) infrastructure."[29]

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."[30]

Q. Did PGE break down their determination of Element 3—T&D Capacity into transmission and distribution?

A. Yes. PGE "proposed value of $21.52 per kW-year for avoided transmission […] [and] a value of $25.35 per kW-year for avoided distribution."[31]

Q. What was PGE's basis for calculating Element 3—T&D Capacity?

A. PGE "used the marginal cost study prepared for Docket No. UE 319 — PGE's 2018 test year rate case. The value for an avoided distribution asset was determined to be the cost of subtransmission costs plus substation costs."[32]

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[29] Order No. 17-357 at 21.
[30] *Id*.
[31] PGE/400 Murtaugh/7.
[32] *Id*.

Q. On what did PGE base the transmission component of Element 3—T&D Capacity?

A. PGE stated that "[t]he avoided transmission value is based on the distributed solar generator's ability to allow PGE to defer the cost of firm transmission service, and the price is based on BPA's 2018 tariffed Firm Point-to-Point transmission service, and the price is based on BPA's 2018 tariffed Firm Point-to-Point transmission service."[33]

[33] *Id*. at 8.

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."[34]

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

A. The Commission required the utilities to "develop hourly averages of avoided marginal line losses attributable to increased penetration of solar PV systems in Oregon service areas. The incremental line loss estimates shall reflect the hours solar PV systems are generating electricity."[35]

Q. How did PGE evaluate their distribution system to determine the value of Element 4—Line Losses?

A. PGE's "distribution system was evaluated during peak loading conditions (summer) as well as light loading conditions (spring). In the models, the distributed solar (aggregate 76 MW) was turned "on" and "off" to calculate the difference in distribution system losses."[36]

Q. How did PGE evaluate their distribution system during peak loading conditions (summer)?

A. PGE's summer studies considered "a net system load of 3519 MW, with on-peak losses at 71.386 MW (no solar) and on-peak losses of 68.218 (76 MW of solar output). The average daily losses calculated for summer conditions were 33.337 MW (no solar) and 31.858 MW (fixed output of 76 MW)."[37] The difference

[34] Order No. 17-357 at 22.
[35] *Id*.
[36] PGE/400 Murtaugh/4.
[37] *Id*.

between average daily losses in PGE's summer study, with and without solar, was 1.474 MW (33.337 MW – 31.858 MW).

Q. How did PGE evaluate their distribution system during light loading conditions (spring)?

A. PGE's spring studies considered "a PGE net system load of 2192 MW, with on-peak losses at 36.480 MW (no solar) and on-peak losses of 34.506 (76 MW of solar output). The average daily losses calculated for [assume spring] conditions were 17.036 MW (no solar) and 16.114 MW (fixed output of 76 MW)."[38] The difference between average daily losses in PGE's spring study, with and with out solar, was 0.922 MW (17.036 MW – 16.114 MW).

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

A. PGE calculated a real levelized value for Element 4—Line Losses of 1.48 $(2017)/MWh.[39] IPCo calculated a real levelized value for standard size of 2.54$/MWh and 0.00 $/MWh for utility scale size projects.[40] PacifiCorp calculated a nominal levelized (2018-2042) value of 1.96 $/MWh using the standard methodology and 2.14 $/MWh using the PDDRR methodology .[41]

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

A. Not at this time.

[38] *Id*. at 5.
[39] PGE/100 Goodspeed/7.
[40] UM 1911, Idaho Power/100 Haener/4.
[41] UM 1910, PAC/100 MacNeil/3.

ELEMENT 5—ADMINISTRATION

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

A. The Commission defined Administration as the "[i]ncreased utility costs of administering solar PV programs."[42]

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."[43]

Q. What costs did PGE include in the determining the value of Element 5—Administration?

A. PGE included costs associated with its "[…] Customer Interconnection Group (which handles net metering inquiries and interactions) and PGE's Specialized Billing group."[44]

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

A. PGE calculated a real levelized value for Element 5—Administration of -5.58 $(2017)/MWh.[45] IPCo calculated a real levelized value for standard size of -47.77$/MWh and 0.00 $/MWh for utility scale size projects.[46] PacifiCorp

[42] Order No. 17-357 at 22.
[43] *Id*.
[44] PGE/100 Goodspeed/12.
[45] *Id*. at 7.
[46] UM 1911, Idaho Power/100 Haener/4.

calculated a nominal levelized (2018-2042) value of -2.88 $/MWh using the standard methodology and the PDDRR methodology .[47]

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

A. Not at this time.

[47] 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."[48]

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

A. The Commission required the utilities to "make estimates of integration costs based on acknowledged integration studies."[49]

Q. How did PGE determine a value for Element 6—Integration?

A. PGE based its value "on acknowledged integration studies."[50]

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

A. PGE calculated a real levelized value for Element 6—Integration of -0.83$(2017)/MWh.[51] IPCo calculated a real levelized value of -0.56$/MWh for standard size and utility scale size projects.[52] PacifiCorp calculated a nominal levelized (2018-2042) value of -0.82 $/MWh using the standard methodology and the PDDRR methodology.[53]

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[48] Order No. 17-357 at 22.
[49] *Id*.
[50] PGE/100 Goodspeed/11.
[51] *Id*. at 7.
[52] UM 1911, Idaho Power/100 Haener/4.
[53] UM 1910, PAC/100 MacNeil/3.

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

A. Not at this time.

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."[54]

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."[55]

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[?]"[56] 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

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[54] Order No. 17-357 at 22.
[55] *Id*.
[56] 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. What value did PGE determine for Element 7—Market Price Response?

A. PGE "[…] estimated an MPR ["Market Price Response"] value of $1.81 per MWh of incremental solar generation in the Western Electricity Coordinating Council (WECC) at the 100 MW level. At the 1,000 MW level, PGE saw an impact of $1.61 MWh of incremental solar generation."[57]

Q. How did PGE determine values for Element 7—Market Price Response?

A. PGE used AURORA to "[…] simulate[] wholesale power market prices in the WECC from 2020–2045 [...]".[58] AURORA calculates PGE's portfolio costs based on "market purchases, sales, and generation."[59]

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[57] PGE/300 Sims/8.
[58] *Id*.
[59] *Id*.

Q. How did PGE consider carbon pricing in its determination of Element 7—Market Price Response?

A. PGE stated that it "removed the impact of potential carbon (CO2) pricing, since this is captured in the "environmental compliance" element."[60]

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

A. PGE calculated a real levelized value for Element 7—Market Price Response of 1.81$(2017)/MWh.[61] IPCo calculated a real levelized value of 0.00$/MWh for standard size and utility scale size projects.[62] PacifiCorp calculated a nominal levelized (2018-2042) value of 0.15 $/MWh using the standard methodology and 0.00 $/MWh using the PDDRR methodology .[63]

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

A. Not at this time.

[60] *Id*. at 9.
[61] PGE/100 Goodspeed/7.
[62] UM 1911, Idaho Power/100 Haener/4.
[63] UM 1910, PAC/100 Macneil/3.

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."[64]

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."[65]

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

A. PGE calculated a real levelized value for Element 8—Hedge Value of 1.25 $(2017)/MWh.[66] IPCo calculated a real levelized value of 1.49 $/MWh for standard size and utility scale size projects.[67] PacifiCorp calculated a nominal levelized (2018-2042) value of 1.54 $/MWh using the standard methodology and 1.68 $/MWh using the PDDRR methodology .[68]

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

A. Not at this time.

[64] OPUC Order No. 17-357 at 22.
[65] OPUC Order No. 17-357 at 22.
[66] PGE/100 Goodspeed/7
[67] UM 1911, Idaho Power/100 Haener/4
[68] UM 1910, PAC/100 Macneil/3(Revised 12/21/17)

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."[69]

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. To value future anticipated standards utilities should use the carbon regulation assumptions from their IRP."[70]

Q. How did PGE describe the calculations to determine the value of Element 9—Environmental Compliance?

A. PGE stated that the calculations "[…] are designed to reflect the difference in the energy value of a solar resource under an environment with carbon prices and without carbon prices."[71]

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

A. PGE calculated a real levelized value for Element 9—Environmental Compliance of 11.41$(2017)/MWh.[72] IPCo calculated a real levelized value of 0.00 $/MWh

[69] Order No. 17-357 at 23.
[70] *Id*.
[71] PGE/500 Carpenter/3.
[72] PGE/100 Goodspeed/7.

for standard size and utility scale size projects.[73] PacifiCorp calculated a nominal levelized (2018-2042) value of 0.11 $/MWh using the standard methodology and 0.22 $/MWh using the PDDRR methodology .[74]

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

A. Not at this time.

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[73] UM 1911, Idaho Power/100 Haener/4

[74] 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."[75]

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."[76]

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."[77]

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.[78]

[75] Order No. 17-357 at 23.
[76] *Id*.
[77] UM 1716, Staff/400 Olson/13.
[78] 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 PGE's value for Element 10—RPS Compliance?

A. Not at this time.

ELEMENT 10—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."[79]

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."[80]

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

A. Not at this time.

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[79] *Id*. at 23.
[80] *Id*.

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

A. Yes. PGE bases its estimated RVOS on values for each element that generally appear to be significantly lower than one would expect based on existing research, resulting in what may be a depressed RVOS estimate. For example, Figure 3 compares the values of each RVOS element used by PGE (as well as PacifiCorp and IPCo) to the values of the same elements according to a meta-analysis performed by the Rocky Mountain Institute in 2013.[81] As a result, even where I have not noted specific disagreement with PGE's methodology, I retain some skepticism and respectfully suggest that the Commission take a hard look at PGE's proposal before approving a final RVOS estimate.

[81] 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 3 above were derived from the range of values included in the Rocky Mountain Institute report for each element of the RVOS calculation.

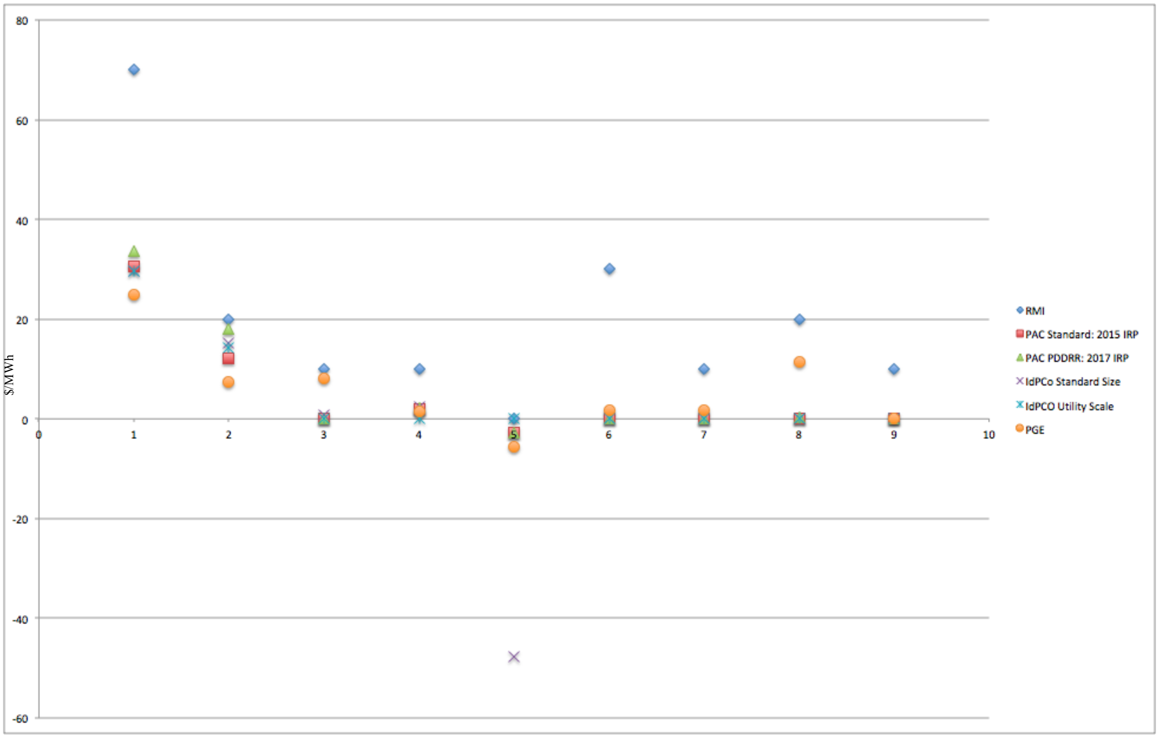

Figure 2: Comparison of PacifiCorp, PGE's and IPCo's values with values derived from RMI study

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.