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A DIVISION OF PACIFICORP

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April 20, 2018

VIA ELECTRONIC FILING AND HUDDLE

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: UM 1910—PacifiCorp's Reply Testimony

PacifiCorp d/b/a Pacific Power hereby submits the reply testimony of PacifiCorp witnesses Daniel J. MacNeil and Kevin Putnam in the above-referenced docket.

Electronic workpapers will be posted to Huddle. Confidential material in support of this filing is provided under Order No. 17-483.

Please direct any questions regarding this filing to me at (503) 813-6583.

Sincerely,

Natasha Siores
Manager, Regulatory Affairs

Enclosures

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's **Reply Testimony** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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UM 1910

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Dated April 20, 2018.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

Docket No. UM 1910
Exhibit PAC/300
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Daniel J. MacNeil

April 2018

REPLY TESTIMONY OF DANIEL J. MACNEIL
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Q. Are you the same Daniel J. MacNeil who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My reply testimony replies to opening testimony filed on March 16, 2018, by Public Utility Commission of Oregon Staff (Staff) witness Ms. Brittany Andrus (Staff/100 and Staff/200), Citizen's Utility Board (CUB) witness William Gehrke (CUB/100-102), Oregon Department of Energy (ODOE) witness Robert DelMar (ODOE/100), Oregon Solar Energy Industries Association (OSEIA) witness R. Thomas Beach (OSEIA/100-102), and Renewable Northwest (RNW) witness Michael O'Brien (RNW/100).

Q. Please summarize your reply testimony.

A. My testimony provides support for five modifications to resource value of solar (RVOS) values based on standard qualifying facility (QF) rates, in response to issues identified by parties as well as corrections identified by PacifiCorp. PacifiCorp has also reflected these changes in the RVOS values based on its partial displacement differential revenue requirement (PDDRR) methodology, and has calculated an additional RVOS sensitivity based on utility-scale solar costs. A summary of these changes is shown in the table below. My testimony also explains why other modifications to the RVOS calculation proposed by parties are inappropriate and provides additional explanation of the relationships between RVOS applications, inputs, and results.

Table 1: Summary of RVOS Results

$/MWh	RVOS Total Value		Delta	
Study	Real	Nominal	Real	Nominal
Standard				
As filed (errata)	32.84	42.92		
+Corrected Admin Cost	33.07	43.21	0.22	0.29
+2018 Start for nominal pricing	33.07	41.03	0.00	(2.18)
+MPR separate from Energy	33.07	41.03	0.01	0.01
+Marginal Line Losses	33.28	41.29	0.21	0.26
+CO2 Price	36.99	45.89	3.71	4.60
Final	36.99	45.89		
PDDRR				
As filed (errata)	39.58	52.00		
Corrections + Updates	43.71	54.23	4.13	2.24
Utility-scale				
Starting 2021	34.22	42.46		
Starting 2030	30.39	37.71		

Q. Are there any elements on which parties have not identified issues?

A. Parties have not identified any issues related to the integration element or the administration element beyond the correction discussed below. Therefore, I will not address those elements here.

RVOS APPLICATIONS AND KEY ASSUMPTIONS

CORRECTIONS

Q. Have you identified any corrections to the RVOS template and inputs since your original filing?

A. Yes. PacifiCorp has identified two corrections since its initial filing. First, in response to CUB data request 4, PacifiCorp identified a correction to administrative costs, which reduced the real-levelized cost by 10 percent. Second, while preparing response testimony, PacifiCorp identified that the reported nominal levelized values reflected a 2020 start date. For comparability, this has been corrected to a 2018 start date in the RVOS template and values reported herein. Depending on the timing of full implementation of an RVOS rate, further adjustments to align with specific applications will be necessary. After accounting for the corrections to administrative costs and a 2018 start date, the RVOS value is $32.84/MWh on a real-levelized basis and $40.75/MWh on a nominal levelized basis.

APPLICATIONS

Q. Are the values reported by the RVOS model universally applicable to solar resources in Oregon?

A. No. The reported RVOS values are only applicable to the extent they accurately correspond with the impact of specific solar resources on PacifiCorp's system. The key variables that impact whether the RVOS will accurately correspond to a specific resource include the generation profile, interconnection voltage, transmission and distribution location, and contract term.

Q. What are the positions of the parties with respect to the solar generation profile?

A. Staff is generally satisfied with the solar generation profile in PacifiCorp's RVOS workbook.[1] ODOE suggests that variations in climate and technology should be analyzed to assess the variation in solar generation profiles on RVOS values.[2] OSEIA takes issue with the inclusion of solar profiles for Portland, Oregon in the aggregate solar shape represented in PacifiCorp's RVOS workbook.[3]

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[1] Staff/200, Andrus/5.
[2] ODOE/100, DelMar/5.
[3] OSEIA/100, Beach/4.

Q. How do you respond?

A. First, PacifiCorp does in fact serve load within Portland, Oregon, contrary to the statement made by OSEIA.[4] Therefore, OSEIA's criticism regarding the inclusion of solar profiles for Portland, Oregon is unfounded. Second, I agree with ODOE that variations in climate and technology should be assessed as part of any application of RVOS values.[5] To address ODOE's concerns as well as Staff's concerns related to capacity contribution values, when addressing the Generation Capacity element, I will discuss RVOS results for several geographic locations and technologies. Third, the solar generation profiles contained within PacifiCorp's RVOS model are a sample intended to demonstrate the functioning of the model rather than a proposal for a particular application. PacifiCorp understands that the use of the RVOS model for a particular application would take place at a later stage in conjunction with consideration of the application in question.

Q. What are the expected applications for RVOS values?

A. I understand that the RVOS values are expected to inform the calculation of bill credit rates for community solar and also the extent of cost-shifting from net metering.

Q. Do solar generation profiles vary significantly within and among these applications?

A. Yes. Community solar is likely to include both fixed and tracking solar technology, with relatively optimized location-specific characteristics, including tilt and shading. Rooftop solar is likely to be less optimized, with tilt determined by available structures and shading based on vegetation and neighboring buildings. In addition,

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[4] OSEIA/100, Beach/4.
[5] ODOE/100, DelMar/5.

solar resources used for net metering may be distinguished between volumes used on-site, and volumes exported to the grid. To the extent the RVOS methodology is used to value volumes exported to the grid, a generation profile consistent with the exported volume should be used, rather than the entire solar resource output.

Q. Are there any other issues that may impact application-specific RVOS calculations?

A. Yes. Interconnection voltage is another issue, and parties do not appear to have articulated any positions on the interconnection voltage inputs to the RVOS model. The RVOS model currently contains inputs reflecting a blend of solar resources, several of which are assumed to be used behind-the-meter at the secondary level, and one of which is assumed to be exported across the transmission system. These are arbitrary designations intended to illustrate the flexibility of the RVOS methodology rather than a specific program.

Q. How do interconnection voltage assumptions in the RVOS methodology relate to net metering?

A. To the extent a residential customer's entire solar output is being valued, that portion of the output that is used behind-the-meter would be credited with avoiding secondary losses. The portion of the output that is exported would be credited with avoiding primary losses.

Q. How do interconnection voltage assumptions in the RVOS methodology relate to community solar?

A. It is unclear at this time as community solar resources could potentially be interconnected at transmission, primary, or secondary voltage. As with net metering, the expected level of exports would determine the level of avoided losses. For instance, community solar resources could potentially be located behind-the-meter, with a single customer hosting a solar resource and sharing some or all of the output with other subscribers.

Q. What are the positions of the parties with regard to transmission and distribution location?

A. Staff and OSEIA support the use of a system-wide average for avoided transmission and distribution infrastructure costs in this proceeding.[6] As OSEIA notes, there are significant opportunities to target distributed energy resources to locations where they provide the greatest value.[7] This also means that many locations provide little or no value. Paying extra for targeted resources and system average costs for everything else results in an overpayment. This issue is discussed in more detail in the testimony of Mr. Putnam (PAC/400).

Q. Do parties take any positions with regard to contract length?

A. It does not appear so. PacifiCorp populated the E3 workbooks for 25 years beginning in 2018, which is consistent with Commission's directive in Order No. 17-357 and the Commission's statement that the application of RVOS to community solar (or any other application) has not yet been determined.[8] Contract length is a critical input for any application of the RVOS methodology.

[6] Staff/100, Andrus/29; OSEIA/100, Beach/13.
[7] OSEIA/100, Beach/20–21.
[8] *See* Order No. 17-357 at 16.

LEVELIZATION AND INFLATION

Q. What issues do parties raise related to levelization and inflation?

A. Staff raises concerns that PacifiCorp reported nominal-levelized results rather than real-levelized results and suggests that both values should be reported.[9] CUB proposes that the inflation rate be set at two percent consistent with Federal Reserve Policy.[10]

Q. Does PacifiCorp have concerns with reporting both real-levelized and nominal-levelized results?

A. No. Real and nominal values are equivalent, but represent different units. Real-levelized and nominal-levelized results can be readily produced from the E3 model, and while real-levelized results may make for easier comparisons between utilities, nominal-levelized results better represent the payment stream a solar resource would receive in a single value. In the current E3 model, real values represent 2018 U.S. dollars in every year, while nominal values represent current year dollars—2018 U.S. dollars in 2018, 2019 U.S. dollars in 2019, 2020 U.S. dollars in 2020, and so on. Because of inflation, 2019 dollars have less value than 2018 dollars, so more of them are required to produce equivalent value. The impact of inflation also compounds each year. Any future payments would necessarily be made in then-current-year dollars, so a nominal levelized value is a convenient way to express these future payments in a single number.

Q. What does a nominal-levelized RVOS value represent?

A. The nominal-levelized RVOS value is a single number, which if paid over the

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[9] Staff/100, Andrus/53–55.
[10] CUB/100, Gehrke/5–7.

levelization period, would result in the same net present value as the nominal stream of annual values. In the current RVOS results, the early years have annual values that are lower than the nominal-levelized value for the 25-year term. If the nominal-levelized value was paid to the RVOS resource during those years, the difference between the annual and levelized values would essentially be a loan or pre-payment, calculated at a 6.66 percent interest rate (the nominal discount rate and PacifiCorp's weighted average cost of capital from the 2015 Integrated Resource Plan (IRP) currently reflected in standard QF avoided cost rates). This loan is repaid in the later years of the term when the annual values exceed the levelized value, so the value is expected to be equivalent by the end of the contract, so long as deliveries are uniform over the contract period.

Q. Is there an alternative levelized payment stream based on real-levelized RVOS values?

A. Yes. Using the real-levelized RVOS value for 2018 and escalating each year's value at inflation produces the same net present value as the single nominal levelized value described above, so long as deliveries are uniform over the contract period.

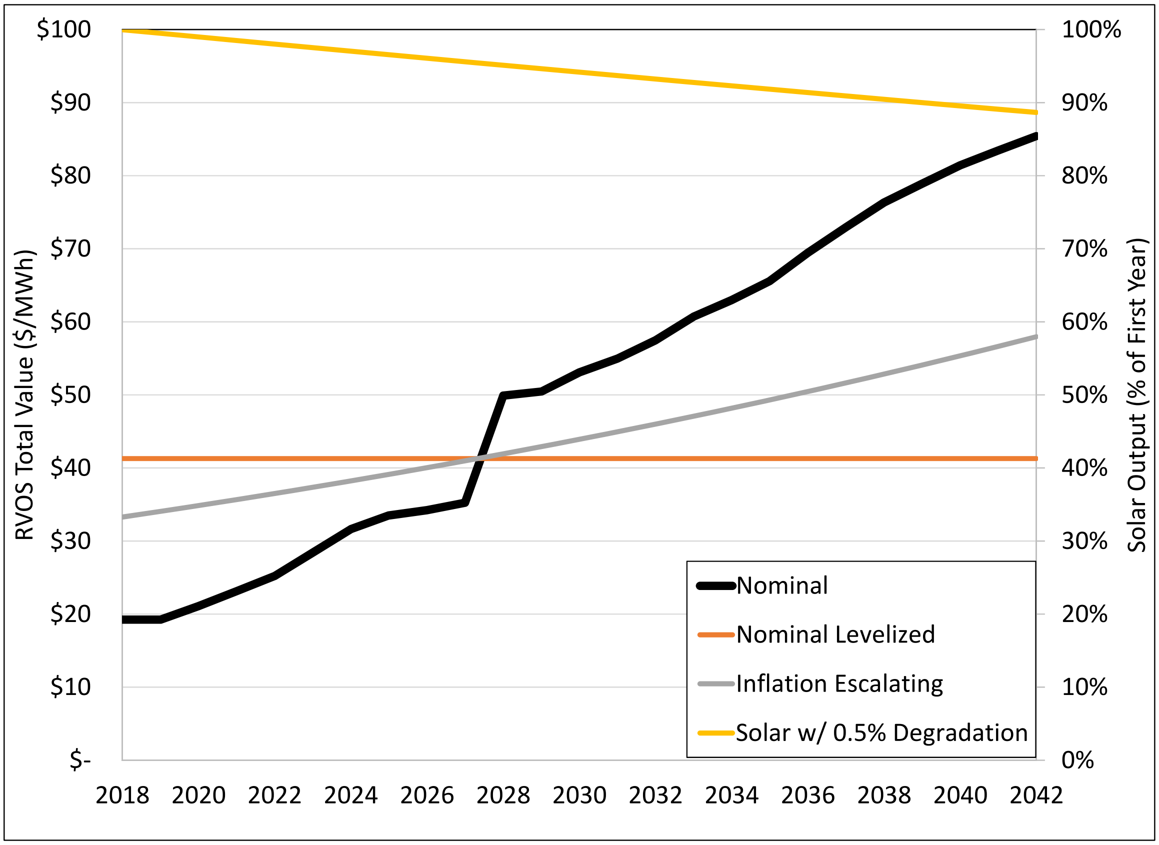
Q. Are there any additional consideration for levelized payments?

A. Yes. First, the RVOS workbook assumes solar resource output is constant over the 25-year study period. Solar resources degrade over time, and are expected to have declining output as time goes on, resulting in less value in future years than indicated in the current template. Second, solar generation output is subject to customer maintenance and repair, and therefore some resources may cease generating before the end of the term, resulting in no value from that point forward. Any program with levelized payments will need to include performance requirements through the end of the levelized term to prevent cost-shifting and protect other customers.

Q. Can you provide an illustration of how annual and levelized RVOS values compare?

A. Yes. Figure 1 shows the annual stream of RVOS values with payment streams that replicate the value of that annual stream over a 25-year contract. The nominal levelized payment stream has the same value over the entire term, $41.29/MWh. The inflation escalating payment stream starts at the real-levelized value of $33.28/MWh in 2018, and escalates at inflation. Figure 1 also shows the impact of solar degradation of 0.5 percent of the previous year's generation. This degradation would result in a six percent reduction in real-levelized value, and, if not accounted for in a levelized payment stream, would result in an overpayment of one to two percent over a 25-year term. Program attrition would similarly result in higher than anticipated non-participating customer costs over the life of a program as reduced resource output and benefits at the end of the term would be inadequate to compensate for front-end levelized payments.

Figure 1: RVOS Payment Streams and Degradation



Q. Is CUB's proposed change to the inflation rate reasonable?

A. No. CUB is incorrect in stating that PacifiCorp's standard company inflation estimate is two percent.[11] PacifiCorp's standard inflation estimate is a curve with annual values calculated as a straight average of forecasts for the Gross Domestic Product (GDP) inflator and the Consumer Price Index (CPI). This standard inflation curve is used in the IRP, and is a core assumption. Changes to the inflation rate used in the IRP would change the outcome of the IRP, including potentially the composition of the preferred portfolio.

[11] CUB/100, Gehrke/7.

UPDATES TO RVOS MODEL

Q. What positions do parties take with regard to updates to the RVOS model?

A. Staff suggests that, for administrative efficiency, updates for energy value should occur in conjunction with annual standard QF avoided cost updates, while also suggesting that forward prices should reflect the most recent curve available, rather than the curve in standard QF avoided cost updates.[12] Staff also suggests that generation capacity, integration and environmental compliance should be updated post-IRP acknowledgment.[13] Finally, Staff suggests that updated values would only be incorporated in new agreements.[14] CUB suggests that annual updates to the RVOS model would be appropriate.[15] RNW suggests that the RVOS should be updated to reflect the latest acknowledged IRP.[16]

Q. Do you have concerns with Staff's proposals for updating RVOS energy values?

A. Yes. Staff's proposals for updating RVOS energy values appear to be contradictory, relying on either the current approved standard QF values or the most recent forward price curve. PacifiCorp is not opposed to calculating avoided costs based on its most recent official forward price curve (OFPC), and already prepares avoided costs using the most recent forward prices for non-standard QFs under its PDDRR methodology. However, the current avoided cost methodology for non-standard QFs includes a market price floor that overrides the most recent results when those results are lower than the approved standard QF values. Staff has argued in support of the market price

[12] Staff/100, Andrus/11–12, 58–59
[13] Staff/100, Andrus/58–59.
[14] Staff/100, Andrus/60.
[15] CUB/100, Gehrke/3–4.
[16] RNW/100, O'Brien/4.

floor, and in favor of using standard QF values for non-standard QF pricing, both of which result in the application of less up-to-date forward prices.[17] It is unclear why Staff believes the most recent forward prices are appropriate for RVOS applications of up to three MW, but not for non-standard QF resources of up to 80 MW. For administrative efficiency, and to avoid having different values for comparable resources under different programs, PacifiCorp supports using consistent assumptions and, to the extent feasible, methodologies, for RVOS, standard QF pricing, and non-standard QF pricing.

Q. Do you have concerns with Staff's proposals for updating RVOS generation capacity values?

A. Yes. Contrary to Staff's proposal to keep generation capacity assumptions static between IRP acknowledgment cycles, generation capacity needs are impacted by long-term contracts executed since an IRP was prepared. The length of time between IRP preparation and acknowledgment and between IRPs may result in significant changes that would necessitate more frequent updates. Identifying executed contracts and applying the capacity contribution values from the IRP should be straightforward, so updating generation capacity needs is reasonable, and should be part of other scheduled updates.

Q. Do you have any concerns with Staff's proposals to apply updated RVOS values only to new agreements?

A. Yes. Since contract length and other details pertaining to the application of RVOS to particular programs have yet to be determined, it is premature to decide whether or

[17] *See, In the Matter of Public Utility Commission of Oregon, Investigation to Examine PacifiCorp, dba Pacific Power's Non-Standard Avoided Cost Pricing,* Staff Opening Brief (Sept 18, 2017).

how updated values would impact previous agreements.

Q. Do you have any comments on RNW's proposal to update the RVOS to reflect the recently acknowledged 2017 IRP?

A. Yes. The current RVOS methodology is tied to PacifiCorp's currently approved standard QF values. While the company is preparing updated standard QF pricing to reflect the Commission's vote to acknowledge the 2017 IRP, the updated prices were not available at the time RVOS testimony was due and have not yet been approved. PacifiCorp intends to provide updated RVOS values incorporating the 2017 IRP when they are available.

ENERGY

Q. What issues do parties raise related to the energy element in PacifiCorp's RVOS filing?

A. Parties raise two issues related to the RVOS energy element. First, Staff and RNW question the use of Energy Imbalance Market (EIM) pricing in the RVOS model, while OSEIA supports the use of EIM pricing, but proposes modifications to the calculation. Second, Staff proposes modifications to the manner in which hydro conditions are incorporated in the energy element. I respond to parties' issues in the following sections.

HOURLY PRICE SHAPING

Q. Please summarize the objections Staff and RNW raise with using EIM pricing in the RVOS model.

A. Staff states that it does not believe PacifiCorp's use of EIM settlement prices provides an appropriate reference point for hourly shaping of prices, noting that "while

PacifiCorp conducts many transactions in the EIM, the majority of its wholesale transactions are not in that market."[18] Staff concludes that it "is not opposed to including EIM values as part of the shaping algorithm, but Staff does not support using EIM settlement values as the sole shaping factor."[19] RNW questions "how informative pricing data from a 5-15 minute spot energy market may be in creating the 12x24 hourly price shape that could be used for the valuation of a long-term firm resource."[20]

Q. Why would it be problematic to use PacifiCorp's short-term wholesale transactions to indicate hourly prices?

A. These short-term wholesale transactions do not provide useful reference points for hourly pricing. The vast majority of PacifiCorp's transactions span large blocks of hours. For example, a day-ahead heavy-load hour transaction spans 16 hours at a single price. Such block transactions do not provide hourly price information. The limited number of hourly transactions that did occur averaged just 64 MW of purchases and 105 MW of sales in 2017. This represents just four percent of PacifiCorp's total short-term firm purchases in 2017 and seven percent of its short-term firm sales.

Q. Are EIM values the "sole shaping factor" for the energy prices used in the RVOS model as Staff suggests?

A. No. The energy prices in the RVOS model are first a function of the monthly forward prices in the company's OFPC. EIM values are only used to shape the monthly prices

[18] Staff/100, Andrus/9.
[19] Staff/100, Andrus/9.
[20] RNW/100, O'Brien/7.

over the 24 hours in each day.

Q. Does the 12x24 hourly shapes in the current RVOS model fully represent the energy value of solar resources?

A. No. As parties note, EIM settlements cover five and 15 minute intervals. These sub-hourly values would also impact the value of variable resources such as solar. Solar resources ramp up and down every day, and there is a significant correlation between the output of an individual resource and of solar resources across the region because both are reliant upon the position of the sun. As a result, when solar resources are ramping up in the morning or down in the evening, it is likely that other solar resources are also ramping in the same direction. Prices tend to decline as available resources increase—this is the same principle underlying the market price response element. As a result, the average energy value of solar will tend to be overstated by an hourly energy price, as the portion of an hour with the greatest solar output will tend to have the lowest price. The impact of sub-hourly solar output changes has not been incorporated in the proposed hourly price shaping based on EIM prices because the current method reflects simple averages of the hourly values.

Q. Are RVOS resources considered long-term firm resources as suggested by RNW?

A. No. Solar resources are contingent upon both solar and mechanical capability, so they are not firm. PacifiCorp compensates for uncertainty and variations in the output of solar resources, and an estimate of this cost is included in the solar integration cost. PacifiCorp is also obligated to carry contingency reserves for solar generation in accordance with North American Electric Reliability Corporation regional reliability standards. PacifiCorp is not obligated to carry contingency reserves for market purchases, and, consistent with the current approved standard QF avoided cost methodology, no adjustment is made to forward market prices to account for this cost during the sufficiency period.

Q. Does Staff or RNW propose an alternative to PacifiCorp's proposal to shape hourly prices using EIM data?

A. No.

Q. What is OSEIA's proposal for hourly price shaping?

A. OSEIA supports the use of EIM data to set hourly price shapes, and proposes that it be adopted by all three utilities, but modifies the methodology to include EIM pricing data as reported.[21] PacifiCorp's proposal capped the EIM pricing results at -$50/MWh and $200/MWh because extreme prices are generally a result of unexpected conditions, which may include significant deviations from forecasted load, wind, or solar. Such deviations are largely random, so the presence of extreme values is generally a chance occurrence, rather than a characteristic of a given hour.

Q. What can cause outlier pricing intervals?

A. EIM is a market for *imbalance*, so outlier pricing occurs when the actual load and resource balance deviates significantly from forecasted levels. A spike in load or drop of variable generation could both result in elevated prices in a particular interval.

Q. Can you provide an example illustrating how extreme values in the historical data distort the results?

A. Yes. The PACW EIM prices for hour ending 13 in June 2017 include one 15 minute

[21] OSEIA/100, Beach/5.

interval with prices of $1000/MWh. Excluding that single 15 minute interval, the average price for that period is $19/MWh, implying a scalar value of 1.49. However, when that single interval is included, the average price jumps to $27/MWh, implying a scalar value of 2.08. Under PacifiCorp's proposal, hours ending 12 and 14 in June have scalar values of 1.14 and 1.18, significantly lower than the capped value of 1.55 for hour-ending 13. With that in mind, the higher scalar value for hour-ending 13 is more akin to a random outlier interval rather than meaningful information about that hour. It is also worth noting that the cap only dampens the impact in hour-ending 13, making it somewhat less extreme, while not completely eliminating it, as evidenced by the significant variation relative to the hours before and after.

Q. Do EIM price caps reduce the average energy price in the RVOS model?

A. No. The average energy price in the RVOS model remains tied to the company's forward price curve. The EIM hourly price shaping only allocates the value among the hours in the day. While prices vary in certain hours as a result of the hourly price shaping, the total value remains equal to the forward market prices, regardless of the shaping methodology.

Q. What do you recommend with regard to hourly energy price shaping?

A. PacifiCorp continues to recommend using hourly energy prices shaped based on EIM prices, with caps applied to reduce the impact of outlier results.

HYDRO CONDITIONS

Q. Please summarize the objections Staff raises with regard to PacifiCorp's adjustment for hydro conditions.

A. Staff believes PacifiCorp "came close" with its approach to the adjustment for hydro conditions.[22] Staff's recommends selecting a random sample of hydro years, creating a forward price curve for each year in the sample, and performing statistical analysis on a set of forward price curves.[23] Staff is also concerned that PacifiCorp uses historical generation, rather than current generation under historical flows.[24]

Q. For which hydro years does PacifiCorp have forward price curves?

A. PacifiCorp has forward price curves based on a normal hydro year, a wet hydro year (1999), and a dry hydro year (1992).

Q. How did PacifiCorp incorporate those hydro years in its initial RVOS filing?

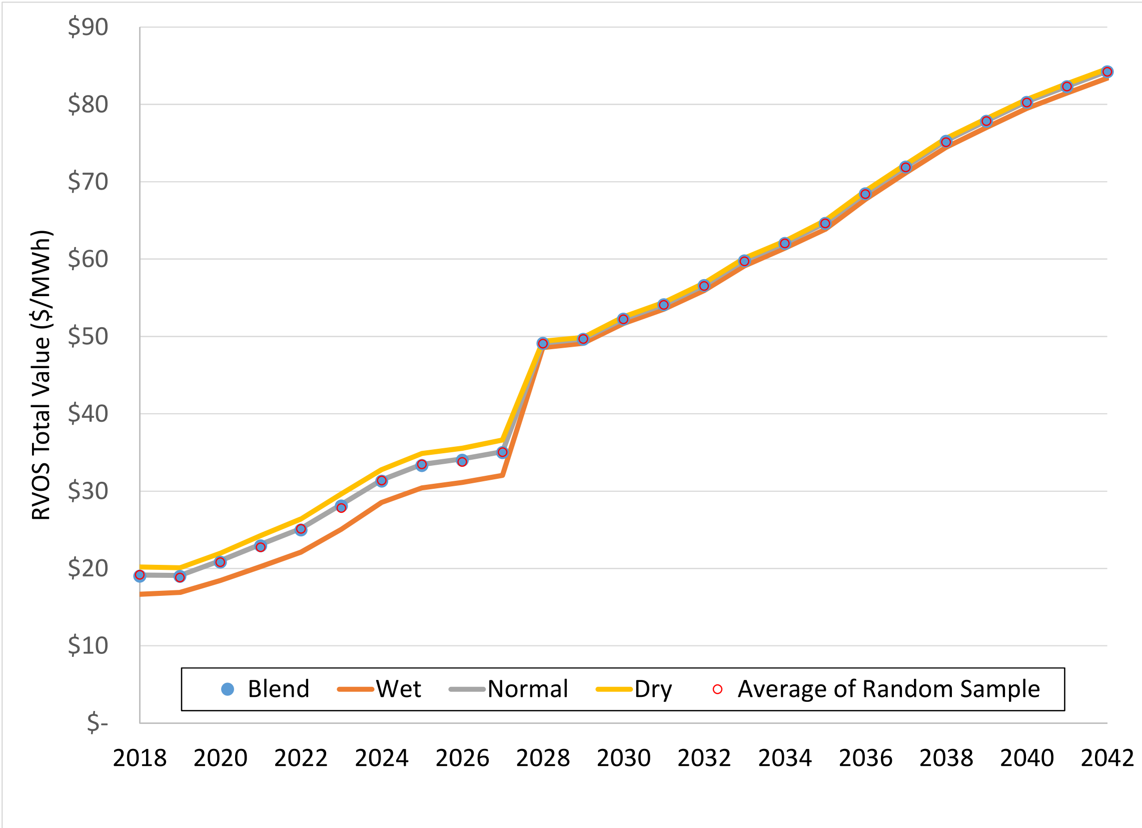
A. PacifiCorp blended the three curves based on the wet and dry conditions in a historical sample of hydro data from 1990 to 2015. As discussed in my direct testimony, wet conditions were given a 20 percent weighting, dry conditions were given a 33 percent weighting, and normal conditions were given a 47 percent weighting. The single blended curve was used in the RVOS workbook.

Q. Has PacifiCorp prepared analysis to address Staff's concerns?

A. Yes. PacifiCorp prepared three versions of its RVOS template, one for each hydro condition. Next, PacifiCorp created one hundred scenarios with random hydro conditions (wet/dry/normal) for each year of the 25-year RVOS study period. The probability of each condition in each year was based on the same weightings described above, 20 percent wet, 33 percent dry, and 47 percent normal. The results are shown in the figure below.

[22] Staff/100, Andrus/16.
[23] Staff/100, Andrus/16.
[24] Staff/100, Andrus/15.

Figure 2: RVOS Total Value by Hydro Condition



Q. What does the analysis show?

A. Using the random sampling technique described above produces a comparable result to that in PacifiCorp's filing—a minor reduction in the forward price curve.

Q. Is it reasonable that the RVOS model does not show a greater impact?

A. Yes. As shown in Figure 2, the variation between wet and dry years is relatively small. This is partly because PacifiCorp's market prices include the California-Oregon Border and Palo Verde markets, which are less affected by hydro conditions. In addition, once RVOS energy prices switch to a gas resource in the deficiency period, the variation becomes minimal, reflecting only minor seasonal variations. While the impact on the RVOS model extends beyond the energy value to the values for avoided line losses and hedging, both of those values use a percentage adjustment, so the magnitude of the change does not impact the result. As a result, using a weighted average price curve is equivalent to using a sample of hydro conditions.

Q. Do you have any other comments on the impact of hydro conditions?

A. Yes. Because PacifiCorp is using a forward price curve that accounts for the risk between the present and the time of delivery, it will already account for some of the known risk associated with variations in hydro conditions.

Q. What do you recommend with regard to the adjustment for hydro conditions?

A. Given the complexity of the analysis, minimal impact on PacifiCorp's RVOS calculation, and potential overlap with value already represented in the forward market price, I question the need for a hydro adjustment in the RVOS methodology. However, PacifiCorp's initial filing made an appropriate hydro adjustment consistent with the Commission's order and that adjustment is continues to be reflected in its updated RVOS model.

MARKET PRICE RESPONSE

Q. What issues do parties raise related to the market price response element?

A. Staff objects to PacifiCorp's calculation of market price response (MPR) outside the RVOS model, recommends that it be reported separately from the energy element, and suggests that PacifiCorp's "value reflects only one year and has not been levelized."[25] Staff agrees with PacifiCorp that the interaction between avoided energy costs and MPR has the potential to double count benefits associated with solar, but recommends PacifiCorp not include it unless it can be calculated with more

[25] Staff/100, Andrus/53-55.

accuracy.[26] OSEIA mistakenly suggests that PacifiCorp used a zero MPR, and proposes using PGE's value of 3.8 percent of avoided energy value as an alternative.[27] RNW notes that the MPR included in the PDDRR results is zero.

Q. Why did PacifiCorp calculate a MPR value outside the RVOS model?

A. The RVOS model uses three basic inputs to determine MPR value over the 25-year study period:

- Start year solar capacity (MW)
- Effect on price of market energy during solar hours ($/MWh) ($2018)
- Net annual market purchases (sales) during solar hours (MWh)

Each of these inputs also has an associated escalation rate that is assumed to be uniform over the study period. PacifiCorp's values for net market purchases and the effect on price of market purchases are more granular than these single values. For instance, PacifiCorp's net market purchase position has periodic step changes as a result of portfolio changes including coal retirements and contract expiration. PacifiCorp's net market position is also comprised of transactions in multiple markets and the blend varies both across the year and over time. PacifiCorp's representation of the MPR for each of these markets is not a single value, but a forecast that varies over time. As a result, PacifiCorp's circumstances are not readily represented by the single value inputs for MPR in the RVOS model.

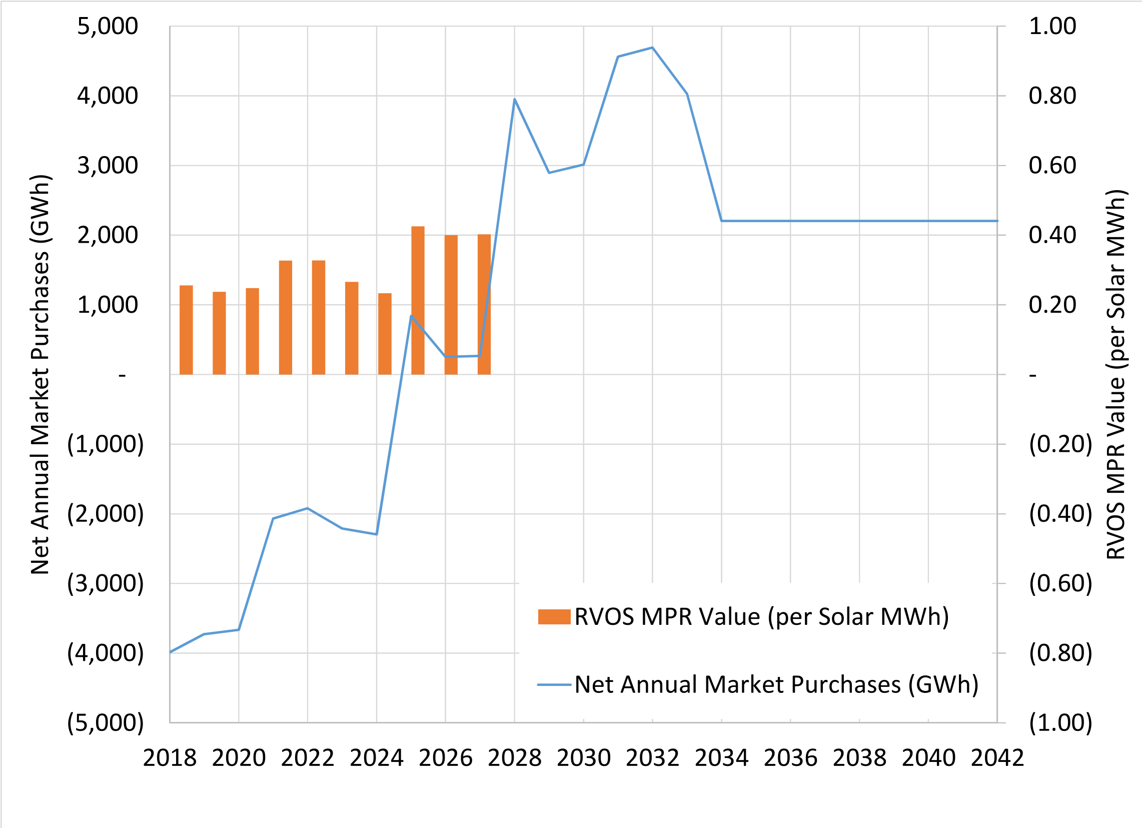
Q. Is Staff correct in its conclusion that PacifiCorp's MPR "value reflects only one year"?[28]

A. No. PacifiCorp calculated a market price response for every year of the study period

[26] Staff/100, Andrus/13-14, 43.
[27] OSEIA/100, Beach/29-30.
[28] Staff/100, Andrus/53-55.

for each of the three major markets that comprise the avoided energy costs in standard QF rates and the RVOS model. The MPR is not uniform across the year, but the small size of the change can be lost in noise in the results. Instead of using the monthly results directly, PacifiCorp calculated a single "normal" monthly shape from across the study period—this is used to spread the annual MPR to monthly heavy-load hour and light-load hour intervals. The annual MPR value per MWh of solar output is shown in Figure 3 below and was provided in the workpapers supporting PacifiCorp's initial filing. The value drops to zero in the deficiency period in 2028 under the standard methodology because the solar resource output is negated by the lost output of the avoided generation capacity resource. Also shown in in Figure 3 below, PacifiCorp starts out with a long market position (net sales) and transitions to a short position over time. While it is not shown in the annual data, throughout the study period PacifiCorp is a net purchaser during summer periods when solar generation is highest, resulting in a net benefit from the MPR during years when PacifiCorp is a net seller.

Figure 3: Market Price Response RVOS Value and Market Position



Q. Can you report PacifiCorp's MPR results separately from the effect of MPR on avoided energy cost?

A. Yes. The MPR values shown in figure 3 above can be included in the RVOS model directly, rather than via the energy input. Inputting these final values bypasses the MPR inputs in the RVOS model described above due to the complexities discussed above. The result is a real levelized RVOS value of $0.15/MWh for the MPR element, but the net increase is close to zero since comparable values were previously included in the energy element. The net impact of minor changes in monthly shaping, losses, and hedging value is an increase to the total RVOS value of less than $0.01/MWh on a real-levelized basis.

Q. Is OSEIA's proposal to use PGE's MPR value of 3.8 percent of avoided energy costs appropriate for PacifiCorp?

A. No. The value from market price response is directly tied to a utility's long or short market position and the markets in which in transacts. As discussed above, PacifiCorp's market position varies over the course of the year and across multiple widely distributed markets. Values calculated for PGE are not an accurate representation of the value to PacifiCorp.

Q. While Staff agrees that solar additions will result in declining avoided energy costs, it suggests PacifiCorp should not adjust avoided energy costs unless it can be calculated with more accuracy.[29] How do you respond?

A. PacifiCorp's avoided energy value only includes the MPR impact based on half of the Oregon distributed solar resource additions between 2018 and 2036 in the 2017 IRP—a total of 150 MW. At this time, PacifiCorp has not made a further adjustment for executed or potential PacifiCorp solar contracts or other WECC solar capacity additions.

GENERATION CAPACITY

Q. What issues do parties raise related to the generation capacity element?

A. Parties raise issues with the generation capacity element that generally fall into two categories. First, parties propose changes to sufficiency period capacity value and timing. Second, parties raise concerns related to the calculation of capacity contribution values. I respond to both issues in the following sections.

[29] Staff/200, Andrus/13–14, 43.

CAPACITY DURING THE SUFFICIENCY PERIOD

Q. What issues do parties raise related to sufficiency period capacity value and timing?

A. Staff and RNW propose that the RVOS resource sufficiency period be updated to reflect the recently acknowledged 2017 IRP.[30] CUB proposes that the sufficiency period be removed from the RVOS calculation, to reflect the capacity value solar projects provide from their first year of operation.[31] OSEIA supports including incremental capacity payments during the sufficiency period based on thermal operations and maintenance (O&M) expenses and proposes accelerating the deficiency period by four years.[32]

Q. Has the Commission provided guidance on the determination of capacity value and deficiency date?

A. Yes. In Order No. 17-357, the Commission ordered that: "all utilities will provide capacity value and timing (deficiency date) in line with their current approved standard non-renewable QF avoided cost capacity value."[33]

Q. Has PacifiCorp complied with the Commission's directive?

A. Yes. PacifiCorp's currently approved standard non-renewable QF avoided cost capacity values are drawn from its 2015 IRP. While the company is preparing updated standard QF pricing to reflect acknowledgment of the 2017 IRP, the updated prices were not available at the time RVOS testimony was due and have not yet been

[30] Staff/100, Andrus/20; RNW/100, O'Brien/10.
[31] CUB/100, Gehrke/5.
[32] OSEIA/100, Beach/10–11.
[33] Order No. 17-357 at 6.

approved. PacifiCorp intends to provide updated RVOS values incorporating the 2017 IRP when they are available.

Q. Does the currently approved standard non-renewable QF pricing include capacity value during the entirety of the sufficiency period?

A. Yes. In Order No. 05-584, the Commission ordered that QF avoided costs be based on monthly on- and off-peak forward market prices, as this "embeds the value of incremental QF capacity in the total market-based avoided cost rate."[34] The Commission recently upheld this position in Order No. 16-174.[35]

Q. In light of the Commission orders on the capacity value of market purchases, does the RVOS model reflect capacity value during the deficiency period?

A. Yes. Because the current RVOS energy value during the deficiency period is based on forward market prices, it includes capacity value. As a result, CUB's proposal to eliminate the sufficiency period to account for capacity value from the first year of operation is unfounded.

Q. Are incremental payments for thermal resource O&M expenses appropriate during the sufficiency period?

A. No. Since energy value during the sufficiency period is based on market prices rather than PacifiCorp's marginal resource dispatch costs, it is inappropriate to include additional O&M costs. OSEIA alludes to this fact by highlighting that PacifiCorp acquires short-term capacity in the form of market transactions.[36]

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[34] *See* Order No. 05-584 at 27–28.
[35] See Order No. 16-174 at 2.
[36] OSEIA/100, Beach/10.

Q. What basis does OSEIA provide for advancing the resource deficiency year?

A. OSEIA suggests that the "smaller capacity increments and shorter lead times" of RVOS resources will allow deployment to more closely match future load growth and capacity needs.[37] OSEIA provides an example and concludes that RVOS resources are undervalued in the absence of additional capacity payments before the year of the next major resource.[38]

Q. Is OSEIA's proposal to advance the resource deficiency year likely to result in more accurate avoided costs?

A. No. Looking at PacifiCorp's 2017 IRP preferred portfolio, the first major non-renewable resource is a 200 MW simple cycle combustion turbine (SCCT) added in 2029. By OSEIA's logic, this "lumpy" resource is likely providing much more capacity than PacifiCorp needs in its first year of operation. If not all of the resource is needed in the first year of operation, a portion of the capacity added in that year could otherwise have come from lower-cost alternatives (i.e. market). In the 2017 IRP preferred portfolio, the capacity from market transactions in 2029 is equal to the maximum available, indicating that the entire SCCT capacity is needed. Furthermore, even if a portion of the SCCT capacity was not needed, that would not imply that customers should be obligated to pay for capacity sooner, it would imply that customer's obligation to pay for at least a portion of that resource could be deferred to a later date.

[37] OSEIA/100, Beach/6–8.
[38] OSEIA/100, Beach/7–8.

Q. Does the company have a generation capacity deferral mechanism that accounts for the relationship between a resource's capacity and the capacity deficiency year?

A. Yes. The PDDRR methodology, which has been approved for pricing non-standard Oregon QFs, assumes that a resource defers a specific increment of a resource addition from PacifiCorp's IRP preferred portfolio. Once an IRP resource addition is fully displaced by QFs, successive QFs displace later resource additions. The IRP resource is reduced in size by exactly the capacity contribution of the QF, even though resources generally must be built in discrete sizes. In reality, a partially displaced capacity resource might still be the most cost-effective solution during the deficiency period, despite contributions from other QF or RVOS resource alternatives. To the extent an IRP resource addition is "lumpy" and "over-sized" relative to the capacity requirement in the year it is added, the PDDRR methodology provides capacity value from deferral of the entire IRP resource, rather than just the need in that year. In that regard, capacity costs under the PDDRR methodology can result in deferral of resources before the year of the need. However, this does not result in payment for capacity costs before the year in which an IRP resource addition is forecasted to occur as proposed by OSEIA.

Q. Does the North Carolina decision allowing QFs to receive capacity payments before a utility's first resource addition provide support for OSEIA's arguments?

A. No. OSEIA misplaces its reliance on the North Carolina Commission decision. The North Carolina Utility Commission recently overturned its 2014 decision, eliminating payments for capacity before the first resource addition.[39]

Q. Have contracts executed since the 2017 IRP was prepared reduced PacifiCorp's generation capacity needs in 2029 relative to what was contemplated in the preferred portfolio?

A. Yes. Since the 2017 IRP was prepared, PacifiCorp has entered into long-term contracts for resources totaling over 500 MW of nameplate capacity and over 150 MW of capacity contribution. The 2015 IRP continues to form the basis for the capacity deficiency year in the currently approved standard QF values, and would be subject to significantly larger changes since it reflects inputs from more than three years ago.

Q. What do you recommend for sufficiency period capacity value and timing?

A. PacifiCorp agrees with the Commission that it is most efficient for the first version of RVOS to use the deficiency year reflected in the currently approved standard QF values, currently 2028 based on the 2015 IRP. Since sufficiency period prices are already based on market, which is the marginal capacity resource in the IRP preferred portfolio during that period, no additional capacity payments are appropriate.

CAPACITY CONTRIBUTION

Q. What issues do parties raise related to the generation capacity element?

A. Staff proposes that the capacity contribution for RVOS should be equal to the value for fixed solar resources identified in PacifiCorp's IRP.[40] OSEIA supports the

[39] *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016*, Docket No. E-100, Sub 148, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Oct 11, 2017) (http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=9b202168-0968-4338-9c64-70b5366ab109)
[40] Staff/200, Andrus/7.

Capacity Factor (CF) method "because it is a consistent, transparent approach that can be readily applied to each of the utilities."[41] ODOE questions the significant change in generation capacity value between the standard methodology under the 2015 IRP and the PDDRR methodology under 2017 IRP.[42] ODOE also requests a comparison of the capacity contributions of fixed tilt solar resources in western Oregon and tracking solar resources in eastern Oregon.[43]

Q. What guidance did the Commission provide on this issue?

A. The Commission indicated that the capacity value and deficiency date should be in line with currently approved standard nonrenewable QF avoided cost capacity value.[44] The Commission also stated that "during a resource deficient period, a utility multiplies the contribution to peak of a QF's resource type by the capacity cost of the utility's avoided proxy resource"[45] and provides an example of how capacity contribution values can be drawn from values from an acknowledged IRP.

Q. Did the Commission provide any guidance on how it will evaluate proposed changes to the RVOS methodology?

A. Yes. The Commission indicated it will balance accuracy, transparency, and accessibility in reviewing alternative approaches.[46]

Q. Is PacifiCorp's IRP based on an approved capacity contribution methodology?

A. Yes. PacifiCorp's 2015 and 2017 IRPs both use the CF method, consistent with Order No. 16-236.

[41] OSEIA/100, Beach/11.
[42] ODOE/100, Delmar/5.
[43] ODOE/100, Delmar/5.
[44] *See* Order No. 17-357 at 6.
[45] *See id* at 7.
[46] *See* Order No. 17-357 at 6.

Q. What are the key inputs to the CF method?

A. The capacity contribution value under the CF method is a function of two inputs: (1) the share of the annual loss of load probability (LOLP) in each hour; and (2) the hourly capacity factor of the resource being evaluated. A resource's capacity contribution is calculated by multiplying these two values for each hour of the study period and summing the result.

Q. Can the RVOS calculation produce the same result as the capacity contribution study in the IRP?

A. Yes. If the same generation profile from the IRP is used, the RVOS template will produce the same capacity contribution value as that reported in the IRP. This is because the RVOS template has been populated with the LOLP values from the IRP, and the RVOS template designed by E3 automatically carries out the same calculation performed for the IRP.

Q. Have you compared the capacity contribution values under the CF method for various solar generation profiles?

A. Yes. The table below shows capacity factors and capacity contribution values for various solar resources, including fixed and tracking solar resources in Oregon, as represented in the 2017 IRP, the solar shape proposed by OSEIA, and the solar shape contained in PacifiCorp's initial RVOS submission.

Table 2: Capacity contribution comparison

Solar Profile	Capacity Factor	Capacity Contribution (2015 IRP)	Capacity Contribution (2017 IRP)
OSEIA Fixed Solar	18.2%	23.7%	43.9%
PacifiCorp Initial RVOS Fixed Solar	20.8%	26.1%	46.5%
2017 IRP Oregon Fixed Solar	23.6%	29.9%	53.9%
2017 IRP Oregon Tracking Solar	26.6%	33.2%	64.8%

Q. What does the table show?

A. Table 2 demonstrates that capacity contribution values increase as the capacity factor of solar resources increases. Since the underlying profiles all reflect the position of the sun, the relationship is relatively linear. In contrast, capacity contribution values for wind resources in the IRP are lower, despite typically having a higher annual capacity factor than solar, due to timing differences. The values for capacity contribution of Oregon solar resources in the 2017 IRP match the values reported in the 2017 IRP. Capacity contribution values for fixed and tracking solar resources based on the 2015 IRP LOLP values vary slightly from values reported in the 2015 IRP because the capacity factor of the solar resources used to calculate capacity contribution was slightly different in the 2015 IRP.

Q. What is the effect of assuming a higher capacity contribution value for a resource with a lower capacity factor?

A. The RVOS model automatically spreads avoided generation capacity costs across the generation profile of the modeled resource. If that generation profile has a smaller capacity factor but the same capacity contribution, capacity payments will necessarily be higher on a per MWh basis. This contradicts the premise of the CF method, which is that all generation delivered during periods with a risk of loss of load equally support reliable system operations. Resources that deliver less generation should be credited for capacity benefits consistent with their generation.

Q. Are rooftop projects likely to have capacity factors that differ from the utility-scale values in the IRP analysis?

A. Yes. Existing PacifiCorp residential net-metering customers have capacity factors that vary widely and range from under 10 percent to over 20 percent. The average capacity factor is approximately 14.5 percent in eastern Oregon and southern Oregon, and approximately 13 percent in the Willamette Valley. Residential solar capacity factors are generally less optimal than utility-scale resources, which typically tilt or track to optimize position with regard to the sun.

Q. Are community solar projects likely to have capacity factors that differ from the utility-scale values in the IRP analysis?

A. It depends. Larger community solar projects are more likely to be optimized similar to utility-scale projects, with ideal panel orientations, low risk of shading, higher DC to AC ratios, and other factors. Smaller community solar projects are likely to be less optimal if they are shaped to a site rather selecting a site primarily based on its solar resources.

Q. Is it appropriate to use the capacity contribution values from the 2017 IRP with the deficiency period from the 2015 IRP?

A. No. An IRP preferred portfolio reflects the least-cost, least-risk plan under specified assumptions including resource costs and alternatives, resource need, generation capacity contribution, and integration costs. Changes in capacity contribution impact PacifiCorp's resource need insofar as those capacity contribution values are applied to PacifiCorp's existing resource portfolio. In the current analysis, switching from the solar capacity contribution values in the 2015 IRP to those in the 2017 IRP would result in a significant increase in capacity from PacifiCorp's existing portfolio of solar resources, which total approximately 1,000 MW. This would in turn reduce the resource need and potentially delay the deficiency period relative to that reflected in the 2015 IRP preferred portfolio.

STANDARD AND PDDRR CAPACITY COMPARISON

Q. ODOE notes the significant change in generation capacity value between the standard methodology and the PDDRR methodology.[47] Please provide more detail on this change.

A. This change is primarily a result of the higher capacity contribution for solar resources in the 2017 IRP, net of reductions due to a one year delay in the deficiency period and lower capacity cost assumptions. Details are shown in the table below.

[47] ODOE/100, Delmar/5.

Table 3: Generation Capacity Value Comparison

Study	Generation Capacity Value ($/MWh) Real	Delta ($/MWh) Real
Standard	$8.65	
+2017 IRP LOLP	$15.39	$6.75
+2028 -> 2029 deficiency	$14.04	($1.35)
+Updated Capacity Cost	$12.72	($1.32)
PDDRR	$12.72	

TRANSMISSION AND DISTRIBUTION CAPACITY

Q. Does PacifiCorp support the changes to avoided transmission and distribution capacity value proposed by parties?

A. No. The specifics of PacifiCorp's position on avoided transmission and distribution capacity values are addressed in the testimony of Mr. Putnam (PAC/400).

Q. Have any inputs related to avoided transmission and distribution capacity changed?

A. No. However, the reported results vary slightly as a result of changes in line losses as discussed below.

LINE LOSSES

Q. Does PacifiCorp support the change to line losses proposed by OSEIA?

A. No. However, PacifiCorp has recalculated avoided line losses on a marginal, rather than average basis. The specifics of PacifiCorp's proposed modifications to the line loss element are addressed in the testimony of Mr. Putnam (PAC/400).

Q. What is the impact of the change to line losses?

A. Updating PacifiCorp's standard RVOS workbook for the changes to line losses described by Mr. Putnam impacts the line loss element as well as the generation capacity and transmission and distribution capacity elements. On a real-levelized basis, incorporating marginal line losses based on PacifiCorp's system data results in a total increase of $0.21/MWh.

HEDGE VALUE

Q. What issues do parties raise related to the hedge value element?

A. Staff supports the use of five percent of the energy price as the proxy hedge value.[48] OSEIA suggests that solar resources reduce the use of natural gas or other market price spikes and proposes alternative hedging values from a 2015 Maine study.[49]

Q. Do you have additional concerns about the five percent hedge value beyond those previously identified?

A. Yes. The five percent hedge value comes from a 2011 study of the risk premium embodied in forward electricity market prices in the Pacific Northwest. The RVOS energy price during the sufficiency period already reflects forward electricity market prices rather than spot prices or marginal resource dispatch cost, so an incremental adjustment for hedge value during the sufficiency period results in a double count. Likewise, the RVOS energy price during the deficiency period already reflects forward gas market prices so an adjustment for hedge value in that time frame is also inappropriate.

Q. Do you have any concerns about OSEIA's proposal for hedge value?

A. Yes. OSEIA's proposal bears no resemblance to PacifiCorp's actual resource planning. First, PacifiCorp is not fueling its gas resources with a 25-year fixed price gas supply, nor is it clear why gas resource costs are an appropriate measure for

[48] Staff/100, Andrus/44–46.
[49] OSEIA/100, Beach/30–34.

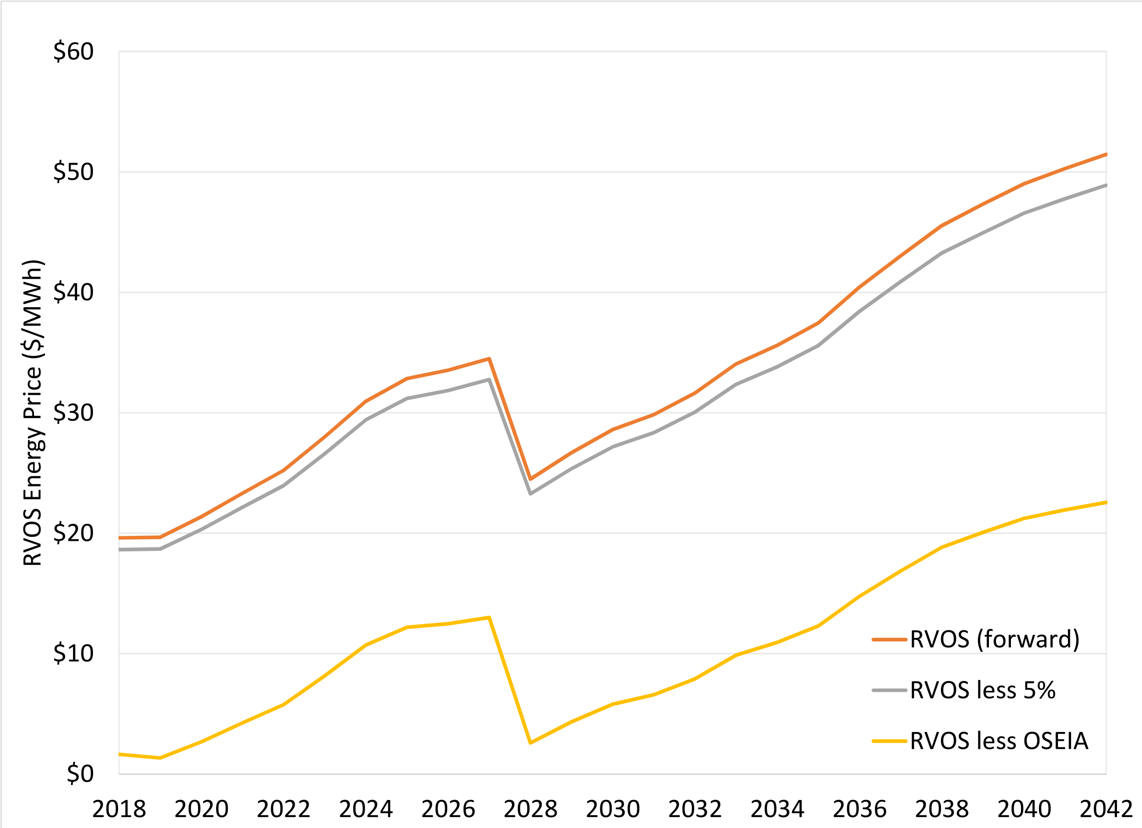
sufficiency period risk when energy values reflect electricity market prices. Second, one of the primary benefits of a gas resource is the ability to adjust its dispatch in response to changing requirements and economics. PacifiCorp's hedging horizon of up to three years dramatically reduces risk without the appreciable costs identified by OSEIA. Over a longer horizon, portfolio changes are an appropriate means of managing risk—a significant and sustained increase in market prices would make a variety of alternative resources more economic, but particularly renewables such as solar. This would be true for all market participants, not just PacifiCorp. Finally, OSEIA suggests that a fixed price gas resource would have the same hedging benefit as an identical renewable resource with zero fuel costs.[50] However, solar resources are not identical and have significantly more delivery risk than a gas resource. If gas prices spike, gas resources can still be operated at a high cost. If it is cloudy or panels are covered in snow, solar resources will under deliver and cannot be operated at any cost.

Q. How big is the implied risk premium calculated by OSEIA?

A. Enormous. PacifiCorp's forward price curve is intended as a forecast of forward prices, i.e. the cost of acquiring volumes for future delivery today. Figure 4 illustrates the current RVOS energy price based on forward prices, and that price with the risk premium removed—the five percent value ordered by the Commission and OSEIA's alternative hedging value of $18/MWh in 2018.

[50] OSEIA/100, Beach/33–34.

Figure 4: RVOS Energy Prices: Forward Versus Spot



Q. What do you recommend for the hedging adjustment in the RVOS?

A. I recommend that the Commission reduce this RVOS element to zero. While the premise of a risk premium may be valid, its application to forward market prices, which already have an embedded risk premium, is inappropriate.

ENVIRONMENTAL COMPLIANCE

Q. What issues do parties raise related to the avoided environmental compliance element?

A. Staff questions the relevance of environmental compliance calculated based on the Clean Power Plan requirements from the 2017 IRP, recommends using alternative CO_2 prices from a sensitivity study in the 2017 IRP, indicates that these prices should be applied based on the results of the PacifiCorp's PDDRR methodology.[51] OSEIA proposes that identical carbon compliance costs should be applied to all utilities, and proposes using PGE's values.[52] OSEIA also proposes that all avoided emissions be calculated based on a natural gas fired resource with a 7,500 Btu per kWh heat rate.[53]

Q. Please clarify the two components of avoided environmental compliance costs.

A. Avoided environmental compliance costs reflect the price of CO_2 emissions and the quantity of avoided CO_2 emissions.

Q. What is the impact of using the alternative CO_2 prices proposed by Staff and OSEIA?

A. The results of the alternative CO_2 pricing proposals are shown in Figure 5. Because incremental CO_2 reductions below Clean Power Plan cap levels are not required, they did not result in avoided environmental compliance costs in PacifiCorp's original analysis. In contrast, the CO_2 prices proposed by Staff result in avoided environmental compliance costs for all CO_2 reductions starting in 2025. Similarly, the CO_2 prices proposed by OSEIA (PGE's values) result in avoided environmental compliance costs for all CO_2 reductions starting in 2022.

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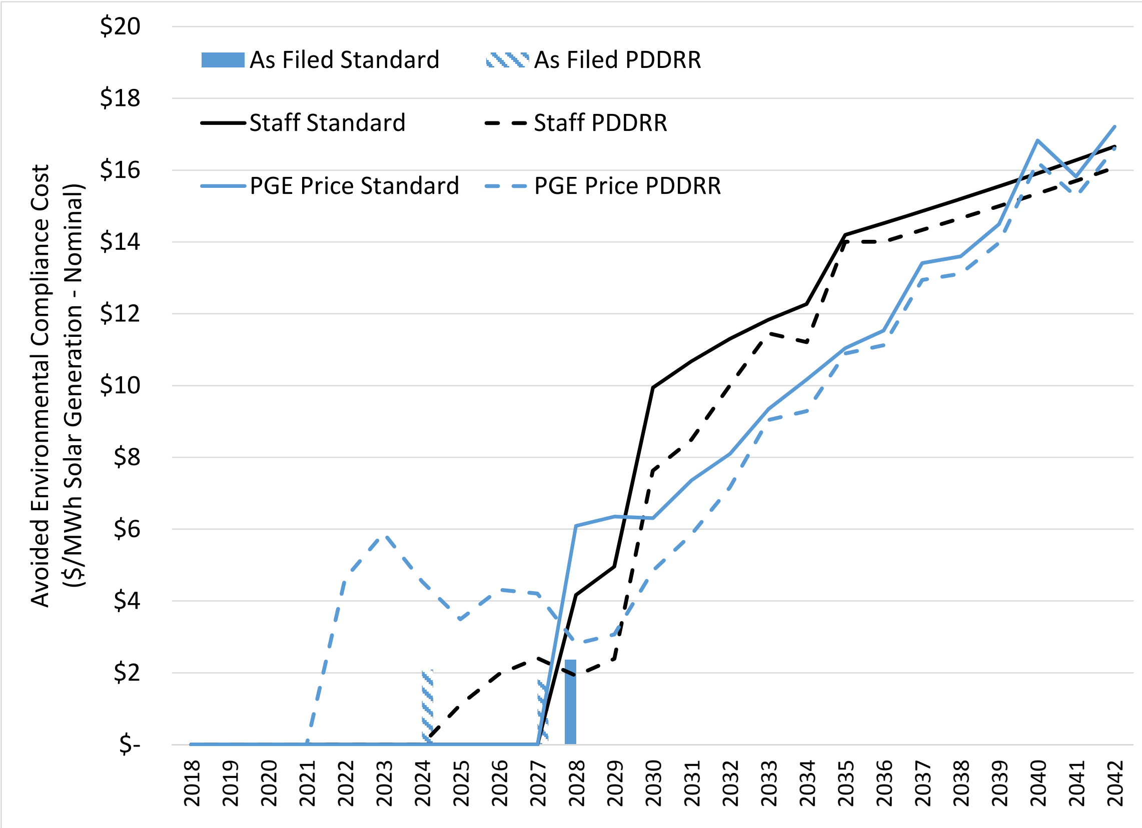
[51] Staff/200, Andrus/15.
[52] OSEIA/100, Beach/34.
[53] OSEIA/100, Beach/35.

Figure 5: Avoided Environmental Compliance Costs



Q. Please explain the difference between the avoided environmental compliance costs based on PacifiCorp's approved standard QF pricing inputs versus using the PDDRR methodology.

A. As explained in my direct testimony, the avoided resource during the sufficiency period under standard QF pricing is market transactions, which have no assumed CO_2 emissions. The avoided resource during the deficiency period under standard QF pricing is a proxy CCCT from PacifiCorp's IRP, with a specified heat rate and emissions. As a result, under the standard QF pricing assumptions, avoided environmental compliance costs are zero through 2027, and then reflect the emissions rate of the proxy CCCT. Under the PDDRR methodology, the Generation and Regulation Initiative Decision Tools (GRID) model determines the avoided resources for each hour of the study period, so emissions rates reflect a weighted average of PacifiCorp's resources, including carbon-emitting coal and gas and market transactions with no associated emissions. Under the PDDRR methodology, emissions begin earlier, and reflect a varying emissions rate that approaches the emissions rate of the proxy CCCT under the standard methodology. By the end of the study period, the results under the standard and PDDRR methodologies and under both proposed CO_2 price alternatives are similar.

Q. Is it appropriate to use avoided environmental compliance costs from the PDDRR methodology as proposed by Staff or based on the gas resource proposed by OSEIA?

A. No, neither approach is appropriate. Staff appears to suggest that avoided environmental compliance costs under the PDDRR methodology should be combined with values for other elements under the standard methodology. Avoided environmental compliance costs should reflect assumptions that are consistent with the avoided energy and generation capacity elements. As such, avoided environmental compliance costs associated with dispatching PacifiCorp's thermal resources are only appropriate if energy prices also reflect the marginal cost of those resources, rather than the higher cost of market transactions. Similarly, it is unclear why avoided environmental compliance costs should be based on a 7,500 Btu per kWh heat rate gas plant when PacifiCorp's proxy gas plant under the standard methodology has a heat rate of 6,530 Btu per kWh.

Q. What do you recommend with regard to avoided environmental compliance costs?

A. For avoided environmental costs, the Commission directed utilities to calculate a value for informational purposes and PacifiCorp has updated its RVOS model to incorporate Staff's CO_2 pricing recommendation as this reflects a potential future environmental compliance scenario that is drawn from the 2017 IRP and represents a reasonable placeholder.

RENEWABLE PORTFOLIO STANDARDS (RPS) COMPLIANCE

Q. What issues do parties raise regarding the avoided RPS compliance cost element?

A. Staff indicates that values from renewable portfolio compliance reports could be applied to the reduction in RPS obligation from distributed solar generation.[54] RNW indicates that is very important to assign a value to RPS compliance before an RVOS estimate is applied to other programs.[55]

Q. Please clarify the two components of avoided RPS compliance costs.

A. Avoided RPS compliance costs reflect the cost of RPS compliance and the impact of a given application on PacifiCorp's RPS compliance position.

Q. Will the impact of a program on PacifiCorp's RPS compliance position vary?

A. Yes. The following two scenarios illustrate this point:

1. Renewable energy certificates (RECs) delivered to PacifiCorp for the benefit of Oregon customers as a whole.
2. RECs delivered to PacifiCorp for the benefit of specified customers.

[54] Staff/100, Andrus/53.
[55] RNW/100, O'Brien/33.

Under example 1, each increment of solar output produces a REC which can be used to meet PacifiCorp's RPS compliance obligation. If one MWh of solar resource is provided to PacifiCorp, the quantity of RECs necessary for RPS compliance is also reduced by one MWh.

Under example 2, each increment of solar output produces a REC that may be retired on behalf of a specific customer. Depending on the program, the customer load may be removed from PacifiCorp's RPS compliance obligation, i.e. PacifiCorp would not need to procure additional RECs for a load that has already been allocated 100 percent renewable energy. The result is not a one-for-one reduction in RPS compliance obligation, but rather a reduction based on the RPS percentage in that year. For instance, PacifiCorp's RPS obligation is 35 percent in 2030. If one MWh of solar resource is allocated to a specified customer in 2030, removing that one MWh of customer load from PacifiCorp's RPS obligation would reduce the quantity of RECs necessary for compliance by 0.35 MWh.

Q. Is there an inter-temporal component to RPS obligations?

A. Yes. Compliance with the Oregon RPS can be achieved with RECs generated in previous years, but this "banking" is subject to certain limits. In combination with the resources in the 2017 IRP preferred portfolio, PacifiCorp's existing REC bank is expected to be sufficient to meet its Oregon RPS compliance obligations until 2035. As a result, incremental costs for RPS compliance are unnecessary until 2035. While some RECs are restricted to a five year banking limit, a significant reduction in load or increase in REC supply over the near-term would be necessary before this impacts RPS compliance costs.

Q. Do the required renewable portfolio standard implementation plans (RPIP) reasonably represent PacifiCorp's avoided RPS compliance costs?

A. No. The incremental cost methodology compares the levelized cost of a qualifying resource acquired based on conditions at the time it was acquired to the cost of a combined cycle plant based on a current forecast of natural gas prices. As a result, the methodology results in an incremental cost for resources that were acquired in the past during periods of high natural gas prices, even though they were the least-cost, least-risk options relative to non-renewable resources at the time they were acquired.

Q. Does the RPIP provide useful information in the context of avoided RPS compliance costs in RVOS?

A. Yes. For example, from 2020 to 2021, PacifiCorp's incremental cost estimates drop significantly and become negative.[56] This is a result of the addition of the 2021 wind resources from the 2017 IRP preferred portfolio, as the incremental cost associated with these resources is negative. Issues with the incremental cost methodology aside, the 2017 IRP preferred portfolio includes the 2021 wind resources because they are least-cost, least-risk before consideration of any additional RPS compliance benefits. This indicates that these resources are lower cost than other alternatives, which is consistent with the negative incremental cost result.

Q. What do you recommend for avoided RPS compliance costs in the RVOS?

A. To the extent renewable resources are cost-effective before considering RPS compliance benefits, avoided RPS compliance costs should be zero. Given the

[56] *See In the Matter of PacifiCorp, dba Pacific Power, 2019-2023 Renewable Portfolio Standard Implementation Plan,* Docket No. UM 1914 (Dec. 28, 2017).

presence of several types of renewable resources in the 2017 IRP preferred portfolio, this is a reasonable outcome. Given that long-term RPS compliance remains on open issue, including avoided RPS compliance cost in RVOS continues to be premature.

GRID SERVICES

Q. What issues do parties raise related to the grid services element?

A. OSEIA suggests that storage paired with solar "has the potential to provide many grid services (such as voltage support, regulation, and load following) as well as to enhance the resiliency of electric service."[57] ODOE highlights advanced technologies such as smart inverters and storage systems that would impact the value of distributed solar resources.[58]

Q. Is it appropriate to consider grid service benefits related to RVOS applications at this time?

A. No. PacifiCorp recently filed a methodology for evaluating energy storage resources in docket UM 1857 that may cover many of the grid services identified by parties. While energy storage resources can provide significant value, much of that value is dependent on the ability of system operators to track and control distributed resource output. PacifiCorp does not currently have programs and systems that would provide those elements, but recognizes that significant potential may exist. Because the greatest benefits are associated with generation capacity needs that PacifiCorp may not have until 2029 or later and evaluation techniques are still under active

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[57] OSEIA/100, Beach/43.
[58] ODOE/100, DelMar/4.

consideration, it is appropriate to leave consideration of the combined benefits of solar and energy storage to a later date.

UTILITY-SCALE ALTERNATIVE

Q. What issues do parties raise related to RVOS values based on a utility-scale alternative?

A. Staff suggests that analysis of the costs of a utility scale solar proxy would provide a helpful reference point for RVOS, and provides several points of clarification about the assumptions it believes would be appropriate in that analysis.[59] OSEIA describes several additional benefits that it believes should distinguish distributed solar from utility-scale solar, beyond avoided T&D capacity, line losses and administrative costs.[60]

Q. What utility-scale alternative did PacifiCorp provide in its direct filing?

A. As discussed in my direct testimony, PacifiCorp provided a calculation using the current PDDRR methodology approved for calculating avoided cost prices for qualifying facilities in Oregon of up to 80 MW.

Q. Has PacifiCorp prepared a utility-scale alternative using a solar proxy?

A. Yes. PacifiCorp's 2017 IRP Update is expected to be filed in early May 2018, and contains an up-to-date estimate of the cost of utility-scale solar resources Oregon. In the 2017 IRP Update, the cost of a utility-scale tracking solar resource in Oregon is $36.06/MWh (2017$), excluding solar integration cost. When this solar resource cost is used in the RVOS model with an assumed start date of 2021, and adjustments for

[59] Staff/100, Andrus/57–58.
[60] OSEIA/100, Beach/40–41.

the T&D capacity, line loss, and administration elements only, the real-levelized RVOS value is $34.22/MWh, or approximately three percent higher than the results based on the standard QF methodology. With an assumed start date of 2030, the real-levelized RVOS value is $30.39/MWh, or approximately nine percent lower than the results based on the standard QF methodology.

Q. What additional benefits does OSEIA ascribe to distributed solar resources relative to utility solar resources?

A. OSEIA states that, relative to utility-scale solar resources, distributed solar can have reduced land use impacts, can allow for more customer choice, and can enhance the reliability and resiliency of electric service when paired with on-site storage.[61]

Q. Is it reasonable for the RVOS model to include these additional benefits?

A. No. The additional benefits described by OSEIA flow to participating customers (or potentially non-customers in the case of land use impacts) whereas the RVOS model is intended to prevent cost-shifting between participating customers and non-participating customers. Because these characteristics of distributed solar do not reduce utility costs, non-participating customers do not benefit, and accounting for them in the RVOS model is inappropriate. If anything, the value individual participating customers ascribe to enhanced reliability, resiliency, and choice of supply would serve to <u>reduce</u> the bill credit rates necessary to encourage customers to adopt net metering or community solar programs.

[61] OSEIA/100, Beach/40-41.

CONCLUSION

Q. Please summarize the recommendations in your reply testimony.

A. With the changes described herein, PacifiCorp's RVOS workbook based on approved standard QF pricing incorporates improvements identified by parties and is consistent with the direction provided by the Commission in Order No. 17-357. As such, it is ready to be populated with inputs and assumptions for specific applications, including details related to generation profile, interconnection voltage, transmission and distribution location, and contract term. I would recommend that in consideration of any application, the results of the RVOS workbook continue to be considered in light of the PDDRR and utility-scale RVOS results and other areas of uncertainty.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UM 1910
Exhibit PAC/400
Witness: Kevin C. Putnam

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Kevin C. Putnam

April 2018

REPLY TESTIMONY OF KEVIN PUTNAM
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Q. Are you the same Kevin Putnam who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. My testimony replies to opening testimony filed on March 16, 2018, by Public Utility Commission of Oregon Staff (Staff) witness Ms. Brittany Andrus (Staff/100 and Staff/200), and Oregon Solar Energy Industries Association (OSEIA) witness R. Thomas Beach (OSEIA/100-102). Specifically, I address inputs for two elements in the resource value of solar (RVOS) calculation: avoided transmission and distribution (T&D) capacity, and avoided line losses. First, I will clarify and explain how PacifiCorp's proposed T&D capacity should be used in the RVOS calculation, because it is a reasonable system-wide average that represents the value of deferring distribution infrastructure attributable to the incremental solar penetration in the Oregon service territory. Second, I will explain the details of the company's revised line loss calculation.

AVOIDED T&D CAPACITY

Q. Staff notes that PacifiCorp's approach "is not a resource value of solar but a resource value of energy efficiency."[1] Do you agree that it would not be appropriate to use a T&D deferral value calculated for energy efficiency?

A. Yes. Using a T&D deferral value calculated based on the characteristics of energy efficiency would not be an appropriate representation of the T&D deferral value of a

[1] Staff/100, Andrus/30.

solar resource.

Q. Did the company use a T&D deferral value specific to energy efficiency for the resource value of solar transmission and distribution deferral value?

A. No. The company clarifies that a T&D deferral value specific to energy efficiency was not used for the T&D deferral value in the RVOS. For the 2017 Integrated Resource Plan (IRP), the company calculated a value that was representative of deferring T&D projects. This value was then modified to create a system-wide average for the 2017 IRP for a specific resource of demand side management. The company did not use this modified system-wide average or "resource value of energy efficiency" within the resource value of solar. The company started with the base value of deferring T&D projects and modified it specific to the solar resource to create a system-wide average that represents the value of deferring distribution infrastructure attributable to the incremental solar penetration in the company's Oregon service territory.

Q. Staff recommends that for the T&D capacity element the company use the marginal cost of service study method used by Portland General Electric Company (PGE) "until a more reliable and transparent location-specific methodology is approved by the Commission."[2] Do you agree with this approach?

A. No. I have two concerns with Staff's recommendation. First, Order No. 17-357 allows PacifiCorp to calculate a system-wide average for the T&D capacity. Second, PacifiCorp has not prepared a marginal cost of service study for its Oregon

[2] Staff/100, Andrus/30.

jurisdiction since March 2013.[3] Since that time, PacifiCorp has revised its approach for developing the marginal cost of transmission and distribution.

Q. What changes has PacifiCorp made in its approach to calculating transmission deferral values since its last Oregon marginal cost of service study?

A. The difference in PacifiCorp's calculation is that the cost of projected transmission additions are divided by the capacity that would be added from the construction instead of the peak load growth projected for the investment horizon as was done in PacifiCorp's previous studies. Using the actual capacity added from the equipment as the denominator is a more accurate reflection of the cost of adding transmission capacity.

Q. Why did PacifiCorp make the change from load growth to capacity added in the transmission calculation?

A. PacifiCorp made this change because using the actual capacity added from transmission equipment as the denominator is a more accurate reflection of the marginal cost of adding transmission than load growth. Transmission investment is also often made to meet reliability standards for existing load. For example, Snow Goose 500-230 kV Substation and Sams Valley 500-230kV Substation were necessary to achieve compliance with North American Electric Reliability Corporation (NERC) Transmission Planning Standards (TPL Standards). Another transmission project, Wallula-McNary 230 kV transmission line, is necessary to enable PacifiCorp to comply with PacifiCorp's Open Access Transmission Tariff (OATT), transmission service agreements, and the Federal Energy Regulatory

[3] *See* Docket No. UE 263.

Commission's (FERC) requirements to provide the requested transmission service. Using load growth would misrepresent the value of these projects in a deferral calculation.

Q. How do the March 2013 marginal cost of service values compare to the calculated transmission and distribution deferral base values?

A. The table below provides these values:

	2013 MCOSS	2017 T&D deferral value
Transmission	**$165.04**	**$5.94**
Distribution Substation	**$22.27**	**$13.44**

Q. OSEIA recommends using a regression analysis of load growth and distribution investment.[4] Do you think that this analysis is useful in the context of a resource value of solar?

A. No. OSEIA's analysis shows that both loads and distribution investment have grown over time.[5] This approach to estimating future distribution deferral from rooftop solar overstates the value for several reasons. First, a correlation between capital additions and increases in load does not necessarily mean there is causality. Second, there are a variety of reasons that investments in distribution must be made. For example, the company is required to relocate distribution lines to accommodate a road that is widened, which results in distribution investment, but is not tied to a capacity or load increase. In the equation, this would increase the numerator (distribution investment) while the denominator (load) remains static creating a false representation of the deferral value. Another example of this would be replacing failed or deteriorated distribution infrastructure. This is a necessary expenditure to maintain service and is

[4] OSEIA/100, Beach/23.
[5] OSEIA/100, Beach/24.

not a deferrable distribution investment expense. By including this type of investment, it has the same effect of increasing the numerator without a corresponding increase to the denominator leading to an inaccurately higher distribution deferral value.

In addition, OSEIA proposes to add a 7.9 percent "general plant loader" and an adder of $22.13 per kW-year for O&M costs to the distribution deferral value. OSEIA provides no clear evidence for why these additional values should be applied to distribution costs deferrable by solar beyond a statement that they were derived from historic costs from the FERC Form 1 report. The vast majority of O&M and general plant are not avoidable by solar. For example, maintenance costs include costs associated with the company complying with OAR 860 division 24 rules. General plant includes items like company trucks and desktop computers. These are not avoidable costs. An example of non-avoidable operations cost would be responding to a downed distribution wire and performing the associated repairs. Using these adders would overstate the distribution deferral value leading to an inflated value for distribution capacity.

Q. What is your recommendation for the T&D deferral value?

A. The company proposes to continue using the T&D deferral value as calculated because it is a reasonable system-wide average that represents the value of deferring distribution infrastructure attributable to the incremental solar penetration in the Oregon service territory. Additional work is necessary because the distribution capacity contribution the company used was based on the analysis of 13 substations that demonstrated a capacity need but does not factor in the remaining 258 substation transformers that do not have a capacity need, which, if factored in, would reduce the value.

Q. Is OSIEA's approach of using a system peak or transmission peak to calculate transmission capacity contribution and the associated deferral benefit attributable to the incremental solar penetration in the Oregon service territory accurate?

A. Yes. I agree in principle that using a system peak or transmission peak could be a representation of when there is potential for transmission deferral benefit. This is dependent on how the system is defined. OSEIA's analysis used available data for the entire PacifiCorp system, but this information is not representative of the peak load in PacifiCorp's Oregon service territory. The peak load times for PacifiCorp's western balancing authority (PACW) or Oregon peak load times would be a more accurate definition of the system and take into account the locational nature of transmission deferral and consequently the resource value of solar in Oregon.

Q. What are the peak load times and associated solar capacity contributions for PacifiCorp's western balancing authority and Oregon jurisdiction?

A. Peak date, time and solar capacity contribution are included in the table below. In this table, the PACW data is based on a 15-minute interval, and the Oregon data is based on a 60-minute interval.

Table 1 – PACW and Oregon Solar Capacity Contribution

PACW	Solar Capacity Contribution	Oregon	Solar Capacity Contribution
12/9/2013 7:30 AM	0.65%	12/9/2013 8:00 AM	0.65%
2/6/2014 7:30 AM	3.46%	2/5/2014 8:00 AM	3.46%
6/30/2015 5:45 PM	18.02%	7/2/2015 5:00 PM	19.37%
12/14/2016 2:00 PM	28.28%	12/14/2016 6:00 PM	0.00%
1/6/2017 7:30 AM	0.65%	1/6/2017 8:00 AM	0.65%

Q. **Please explain how the solar capacity contributions at the peak demonstrate the challenges associated with using solar to defer transmission projects.**

A. As shown in Table 1, during three of the last five years in Oregon, the solar capacity contribution was zero or near zero at peak load time. Moreover, this analysis does not include the additional risks associated with utilizing solar as a transmission deferral mechanism such as the potential for clouds or snow covering the solar generation.

Q. **Have you reviewed OSIEA's proposed peak capacity allocation factor (PCAF) methodology and the calculation?**

A. Yes. I reviewed the file supplied by OSIEA titled "Distribution PCAFs – PAC and PGE."

Q. **Did the company find flaws with this calculation that required corrections?**

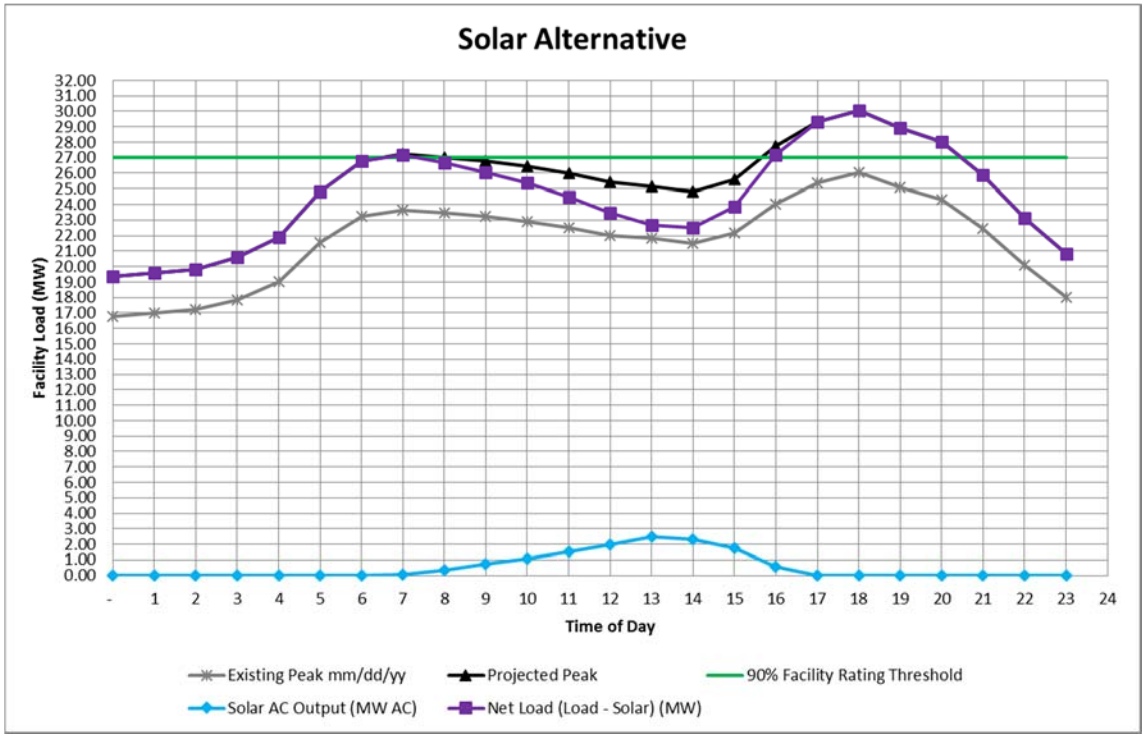
Yes. The company provided the available hourly 8,760 data for the requested items in the response to Renewable Northwest data request 5. In reviewing the calculation performed by OSEIA, the data included an interval that appears to be the power flow under a fault condition or an erroneous value, not a value due to normal loading. The company adjusted this single value to a reasonable loading number. The company also removed the Dorris Substation loading data due to its location in California.

These modifications resulted in a distribution capacity contribution of 22.4 percent rather than 35.5 percent using OSIEA's proposed methodology.

Q. Do you have any additional comments regarding OSEIA's methodology?

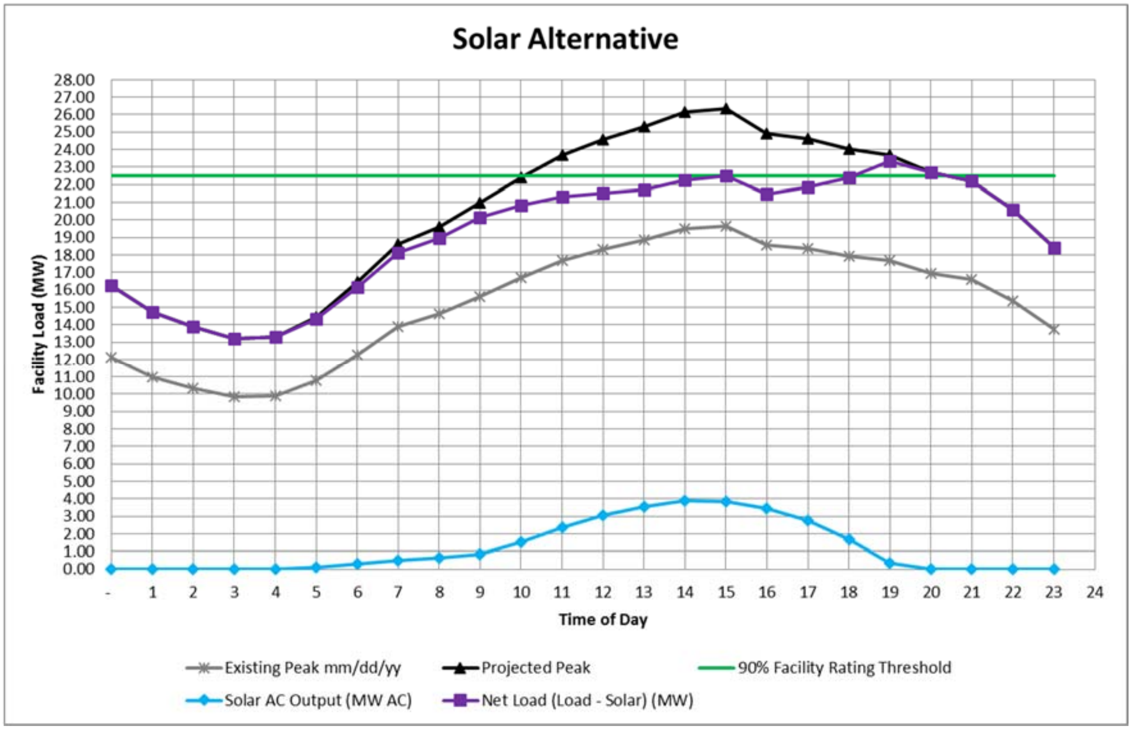
A. Yes. The methodology does not consider the coincidence of the solar generation to the actual peak times to insure that the resource could actually defer the distribution infrastructure improvement cost. Figure 1 below illustrates the alternative evaluation of a winter-peaking substation that was included in OSIEA's PCAF calculation. The company also calculated an individual distribution capacity contribution for this substation based on the methodology, which is five percent. This five percent can be seen in Figure 1 below in that the solar does contribute for a minimal amount of time of the loading above 90 percent but would not contribute to the distribution deferral due to the non-coincidence with the load peak later in the day. This would lead to the company's customers paying a distribution deferral credit and also paying for the distribution infrastructure improvement.

Figure 1 –Evaluation of Winter-Peaking Substation



The company completed the same analysis for a summer peaking substation using the same methodology. The individual PCAF would be 38.5 percent; however, in the alternative analysis the solar resource does not provide full coverage for the deferral in hour 19 and 20.

Figure 2 –Evaluation of Summer-Peaking Substation



The non-coincidence of solar generation with peak load can also be inferred in figures 2 and 3 provided in OSIEA's testimony, which demonstrate the majority of the PCAF allocation occurring past hour 1800 in both figures.

This method also has a similar deficiency to the company method which only evaluates locations that were constrained while ignoring the remaining locations that have no loading constraints which presents zero deferral opportunity but would apply the same distribution capacity contributions to those substation transformers which overstates the value of solar.

Q. Does the PacifiCorp have any additional analysis regarding the PCAF methodology?

A. Yes. The company evaluated what portion of the distribution capacity contribution was from the Oregon peak day on 1/6/2017. Table 2 below demonstrates that the distribution capacity contribution is being credited with 4.51 percent of the total 22.4 percent. It also shows there are considerable hours during the day that exceeded the 90 percent that solar did not contribute. In addition, comparing this to the actual peak time of the Oregon peak shows that solar does not contribute to actual distribution deferral. This demonstrates that the distribution capacity contribution of solar is being over-stated by this methodology for Oregon customers, which would result in "double-paying" for distribution capacity.

Table 2 – Distribution Capacity Contribution From Peak

Date and Time	Wtd. Average	Redmond PV Watts	PCAF
1/6/2017 0:00	0.000261134	0	0
1/6/2017 1:00	0.0002529	0	0
1/6/2017 2:00	0.000215045	0	0
1/6/2017 3:00	0.000251543	0	0
1/6/2017 4:00	0.000186225	0	0
1/6/2017 5:00	0.000271745	0	0
1/6/2017 6:00	0.030030468	0	0
1/6/2017 7:00	0.089413181	0.0162558	0.001453483
1/6/2017 8:00	0.03661197	0.2137749	0.00782672
1/6/2017 9:00	0.068580081	0.4363581	0.029925474
1/6/2017 10:00	0.008603212	0.5782608	0.0049749
1/6/2017 11:00	0.000954179	0.6472044	0.000617549
1/6/2017 12:00	0.00037897	0.6378399	0.000241722
1/6/2017 13:00	7.17763E-05	0.6008136	4.31242E-05
1/6/2017 14:00	0	0.4792338	0
1/6/2017 15:00	0	0.2841759	0
1/6/2017 16:00	0.000152715	0.0604599	9.23312E-06
1/6/2017 17:00	0.000907883	0	0
1/6/2017 18:00	0.002124241	0	0
1/6/2017 19:00	0.000979707	0	0
1/6/2017 20:00	0.000184126	0	0
1/6/2017 21:00	0	0	0
1/6/2017 22:00	0.000163687	0	0
1/6/2017 23:00	1.30716E-05	0	0
1/7/2017 0:00	0	0	0
		Sum of PCAF:	4.51%

Q. Does PacifiCorp have a recommendation regarding the PACF methodology?

A. Yes, parties agree that solar only avoids transmission and distribution capacity cost to the extent that solar production occurs at times of peak load demand on the T&D system.[6] The PCAF methodology does not adequately assess the coincidence of the solar generation and peak load demand on the constrained elements of the T&D system. The company recommends continuing to use its current calculation that considers both loading constraints and coincidence of solar production to peak load.

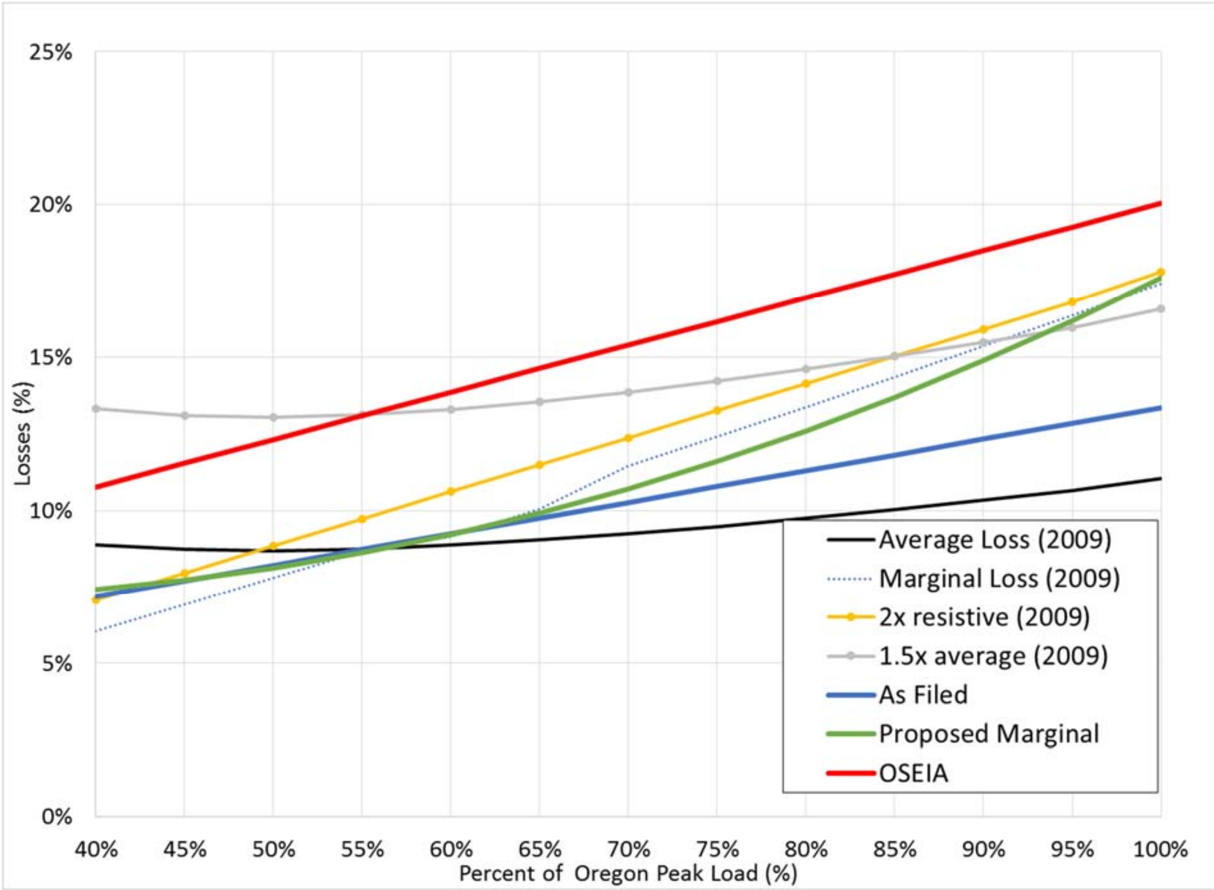
AVOIDED LINE LOSSES

Q. Has PacifiCorp changed the line loss calculation from its direct filing?

A. Yes. PacifiCorp used the results from its power flow studies to calculate a marginal loss by load level and then fitted to a 12 month and 24 hour profile for resources connected at either the primary or secondary voltage level. This resulted in an increase of 9.5 percent to the line loss element from the original. In addition, PacifiCorp calculated a marginal line loss, two times resistive and 1.5 times average line losses based on the 2009 line loss study to create a comparison for results. The results are presented in Figure 3 below. The proposed marginal losses closely align to the marginal loss calculated off the 2009 line loss study and is similar to twice resistive losses calculated from the 2009 study that is expected.

[6] OSIEA/100, Beach/12.

Figure 3 - Comparison of Line Loss Calculations



Q. Does PacifiCorp support using a 1.5 multiplier of average line losses as proposed by OSEIA?[7]

A. No. The Regulatory Assistance Project study referenced by OSEIA points out that marginal losses are actually lower at low loads than the 1.5 multiplier and higher at high loads.[8] As demonstrated in the chart above, applying the factor would reduce the value of the avoided line losses at peak load and overstate the value at lower load factors.

[7] OSEIA/100, Beach/25-26.
[8] Regulatory Assistance Project, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements (August 2011), at 5. See http://www.raponline.org/wpcontent/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

Q. Does this conclude your reply testimony?

A. Yes.