Docket No. 20000-___-EA-18
Witness: Daniel J. MacNeil

BEFORE THE WYOMING PUBLIC SERVICE
COMMISSION

ROCKY MOUNTAIN POWER

Direct Testimony of Daniel J. MacNeil

November 2018

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power (the "Company").

A. My name is Daniel J. MacNeil. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Resource and Commercial Strategy Adviser.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining the Company, I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by the Company since 2008, first as a member of the net power costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to the Company's resource portfolio and obligations, including oversight of the calculation of avoided cost pricing in the Company's jurisdictions.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony in Wyoming dockets 20000-505-EC-16 and 20000-518-EA-17. I have also provided testimony in Utah, Oregon, and Federal Energy Regulatory Commission ("FERC") dockets.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony provides support for the Company's proposed changes to the avoided cost methodology, terms, and procedures applicable to qualifying facilities eligible for standard prices under Wyoming Schedule 37 and non-standard prices under Wyoming Schedule 38. I address three primary areas. First, I propose refinements to the Partial Displacement Differential Revenue Requirement ("PDDRR") methodology that is currently approved for use in determining non-standard avoided costs under Schedule 38. Second, I provide support for the adoption of the same methodology implemented under Schedule 38 to set the published pricing contained within Schedule 37. Third, I propose changes to the on-peak and off-peak definitions contained in Schedule 37 to better differentiate between periods of higher and lower avoided cost.

Q. How is your testimony organized?

A. My testimony first describes the currently approved and effective PDDRR methodology for determining non-standard avoided costs under Schedule 38. I next describe how the PDDRR methodology is implemented based on the 2017 Integrated Resource Plan ("IRP") Update preferred portfolio and describe refinements of the determination of proxy resources for various qualifying facility ("QF") types. In particular, my testimony demonstrates that the deferral of cost-effective renewable resources from the IRP preferred portfolio by QFs of the same type produces the most reasonable forecast of avoided cost consistent with the customer indifference standard.

Next, my testimony provides justification for the adoption of the same methodology implemented under Schedule 38 to determine published pricing for

Schedule 37, Avoided Cost Purchases from Qualifying Facilities. My testimony demonstrates that the PDDRR methodology better captures the specific operational characteristics of different resource types and is more consistent with the customer indifference standard.

Finally, my testimony illustrates how the current on-peak and off-peak definitions within Schedule 37, also commonly referred to as Heavy Load Hours ("HLH") and Light Load Hours ("LLH"), fail to adequately distinguish between periods of higher and lower avoided costs. For instance, as a result of the proliferation of solar generation on the Company's system and across the West, market prices during the middle of the day, which is currently considered on-peak, are now often lower than market prices at night, which is currently considered off-peak. Because the current Schedule 37 methodology applies a single on-peak energy value to all resource types, it fails to appropriately account for the difference in avoided cost value, for instance between solar resources delivering during only part of the on-peak period and baseload resources delivering throughout the on-peak period. While the existing non-standard avoided cost methodology appropriately accounts for the value during each hour, the current delineation of on-peak and off-peak pricing does not provide appropriate price signals to incentivize QF generation during the periods when the Company's avoided costs are the highest.

Q. What standard is used to measure the accuracy of avoided cost pricing?

A. The Public Utility Regulatory Policies Act of 1978 ("PURPA") specifies that QFs are to be paid a rate that is "just and reasonable to the electric consumers of the electric utility" and may not exceed a utility's "incremental cost of alternative electric energy".

The accuracy of avoided cost pricing relative to these requirements is known as the customer indifference standard.[1,2]

Q. How is the PDDRR methodology consistent with the customer indifference standard?

A. The PDDRR methodology provides a reasonable forecast of the Company's avoided capacity and energy costs by:

- Incorporating the unique characteristics of each QF resource and the Company's system by using the Generation and Regulation Initiative Decision Tools ("GRID") model to calculate the value of energy and capacity from QFs to directly measure the impact each QF facility has on the Company's power costs. This accounts for QF location, delivery pattern, and capacity contribution.
- Aligning with the Company's long-term resource plan by incorporating the cost, timing, and characteristics of the preferred portfolio identified in the IRP.
- Capturing the impact of individual and aggregate QFs on the Company's system, accounting for unique characteristics of each QF.
- Appropriately accounting for the seven factors identified in the PURPA statute,

[1] FERC has affirmed the need to ensure customer indifference to utility purchases of QF power, noting that, in enacting PURPA, "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives." Southern Cal. Edison Co., et al., 71 FERC ¶ 61,269 at 62,080 (1995) overruled on other grounds, Cal Pub. Util. Comm'n, 133 FERC ¶ 61,059 (2010). See also PSC of Oklahoma v. State ex. rel. Corp. Comm'n, 115 P.3d 861, 870-71 (Okla. 2005) ("The incremental cost standard is intended to leave ratepayers economically indifferent to the source of a utility's energy by ensuring that the cost to the utility of purchasing power from a QF does not exceed the cost the utility would incur in the absence of the QF purchase").

[2] See, e.g., IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER, FORMERLY KNOWN AS PACIFICORP, TO IMPLEMENT AVOIDED COST METHODOLOGIES FOR PROJECTS OVER ONE MEGAWATT PURSUANT TO THE TERMS OF COMMITMENT WY 4, Docket No. 20000-250-EA-06, March 20, 2007 Order at 45. ("the Commission finds Rocky Mountain's proposed avoided cost methodologies, as contained in its application, using the GRID model, provide fair costs to QFs and does not set costs at a level that will cause customers to incur unnecessary costs.")

specifically under 18 CFR §292.304(e)(2).

PDDRR METHODOLOGY

Q. Please describe the methodology the Company currently uses to determine avoided costs under Schedule 38.

A. The PDDRR methodology used to determine avoided costs was first established on interim basis by the Commission's November 30, 2009 order in Docket No. 20000-342-EA-09 and was adopted permanently by the Commission's November 4, 2011 order in Docket No. 20000-388-EA-11. The PDDRR methodology forecasts avoided fixed costs from a proxy resource and avoided energy costs associated with incremental generation from a particular QF project. Avoided fixed costs include avoided capital costs, which is based on the capital cost of a proxy resource expressed in dollars per kilowatt. The proxy resource is identified as the next deferrable generating unit in the Company's most recent IRP. The avoided capital cost is calculated using the operating characteristics and payment factor identified in the IRP for the deferred proxy resource. The avoided fixed costs also include non-fuel fixed and variable operation and maintenance costs associated with the deferred proxy resource as reported in the IRP. To convert the proxy plant capital cost, grossed up for revenue requirement, to an annual cost per kilowatt, the method uses the IRP resource payment factor as the basis for the real levelized annual cost of the present value of the investment and adds inflation annually thereafter. The non-fuel variable operation and maintenance costs are converted into an annual cost per kilowatt, using the relevant reported capacity factors in the IRP, adjusted for inflation, and this amount is added to the annual avoided capital cost calculation. This produces avoided fixed costs that increase over time.

The PDDRR methodology also produces a forecast of avoided energy costs associated with a particular QF project. This is achieved by simulating the hourly operation of the Company's utility system using the GRID model. Two GRID runs are performed to calculate hourly avoided energy cost. The first run is the existing utility system plus the planned resources contained in the Company's preferred portfolio in its most recent IRP; the second run is the same as the first run with two exceptions: the operating characteristics of the proposed QF project are added with its energy dispatched at zero cost and the capacity of the proxy IRP resource is reduced by an amount equal to the capacity contribution of the QF project. The difference in production costs between the two runs is the avoided energy cost.

Q. What is the fundamental premise of the PDDRR methodology?

A. The Company's IRP preferred portfolio is the least-cost, least-risk plan to reliably meet system load. While the GRID model can reasonably account for the differences in energy value between resources in two geographic locations, to maintain a consistent load and resource balance, it is important to maintain the total effective capacity contribution identified in the preferred portfolio, as this meets the system planning reserve margin assumed in the IRP. For that reason, a QF defers IRP resources based on equivalent capacity contributions.

Q. How is the proxy IRP resource determined under the current PDDRR methodology?

A. Under the current methodology, non-wind QF resources displace proxy gas resources identified in the Company's most recently filed IRP or IRP Update preferred portfolio, while wind QFs defer wind resources from the preferred portfolio.[3]

Q. Has the composition of the Company's IRP preferred portfolio changed over time?

A. Yes. At times, IRP preferred portfolios have not included any wind resources, such that there was no proxy available for wind QFs to displace under the current PDDRR methodology. Likewise, the 2017 IRP Update preferred portfolio did not include any thermal resources, such that there is no proxy available for non-wind QFs to displace under the approved PDDRR methodology. In addition, recent IRP preferred portfolios have included cost-effective proxy solar resources that are not contemplated for deferral under the current PDDRR methodology.

Q. What changes to the proxy IRP resource determination do you propose?

A. In light of the variations in the IRP preferred portfolio described above, a more nuanced determination of proxy resources is appropriate. Therefore, when the Company's IRP preferred portfolio includes renewable resources to meet system load (as opposed to state-specific obligations) that are the same type as a QF project, the forecast of avoided capacity costs are based on the assumed fixed costs of the next deferrable renewable resource. If no renewable resources of the same type (as a QF) remain in the IRP preferred portfolio, the QF would be assumed to defer thermal resources, and avoided capacity costs would be based on the capital costs of the next deferrable thermal resource in the IRP preferred portfolio. In addition, in the years prior to deferral of a proxy renewable or thermal resource, all QFs are eligible to defer front office

[3] Docket No. 20000-388-EA-11. Commission Order dated November 4, 2011, pg. 2; and direct testimony of Greg Duvall, Docket No. 20000-388-EA-11, pg. 5-6.

transactions ("FOTs") identified in the IRP preferred portfolio.[4]

Q. What is meant by renewables of the same type?

A. The "type" is meant to reflect the operational characteristics of the QF on PacifiCorp's system, not the specific technology of the resource identified in the preferred portfolio. For instance, the 2017 IRP preferred portfolio included wind, solar, and geothermal resources. The geothermal resource in the 2017 IRP preferred portfolio is expected to have a flat generation profile with little daily or seasonal variation. Biomass, biogas, hydro, and other renewable resources with similar output profiles would also be eligible to displace the geothermal resource. Any resource with relatively flat output over a daily and monthly timeframe would be considered a resource of the same type as the geothermal resource in the 2017 IRP.

Q. How much of an IRP proxy resource does a QF defer?

A. A QF defers IRP resources based on equivalent capacity contributions, with values reflecting the assumptions used in the development of the most recent IRP preferred portfolio. For example, wind and solar capacity contribution values from the 2017 IRP continued to be used in the 2017 IRP Update and are shown in the table below.

Table 1: 2017 IRP Capacity Contribution Values[5]

East			West		
Wind	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**	**Wind**	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**
15.8%	37.9%	59.7%	11.8%	53.9%	64.8%

[4] FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the Company cover short positions. FOTs represent short-term firm market purchases for physical delivery of power and contribute capacity toward meeting the IRP target planning reserve margin.

[5] 2017 IRP. Volume II. Appendix N: Wind and Solar Capacity Contribution Study. www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf.

Q. What deferrable resources were identified in the 2017 IRP Update preferred portfolio?

A. The 2017 IRP Update preferred portfolio includes the following deferrable resources:

Wind:

- 2021: Wyoming wind (1,311 megawatt ("MW"))
- 2030: Dave Johnston wind (Wyoming) (121 MW)
- 2033: Goshen wind (Idaho) (800 MW)
- 2035: Oregon/Washington wind (333 MW)
- 2036: Utah wind (149 MW)

Solar:

- 2030-2033: Oregon/Washington solar (1,055 MW)
- 2033-2035: Utah South solar (805 MW)

Q. What would the proxy resource be for a baseload resource?

A. Since there are no thermal resources in the 2017 IRP Update preferred portfolio, baseload resources would be eligible to defer FOTs throughout their contract term.

Q. Are there additional considerations associated with capacity deferral by other renewable resource types?

A. Yes. Resources that can be economically dispatched by the Company to their maximum output would have capacity contributions based on that output. Resources that cannot be economically dispatched by the Company have capacity contributions based on their expected output relative to the availability of the deferrable thermal or baseload resource identified in the IRP. Resources with seasonal variations in output would have capacity contributions based on their output during the months of the Company's peak load requirements, as identified in the loss of load probability study used to develop the wind and solar capacity contribution values in the IRP.[6] These distinctions ensure that the capacity provided by a QF is equivalent to the capacity being removed from the IRP preferred portfolio.

Q. Can you provide an example of the capacity contribution applicable to a QF with seasonal variability?

A. Yes. The Company recently executed a contract with a cogeneration QF in Idaho with a nameplate capacity of 5.6 MW.[7] The QF is not expected to have significant intra-hour or intra-day variations in generation, but its monthly expected generation varies from 4.0 MW in September to 4.7 MW in December. When the monthly expected generation is weighted based on the monthly loss of load probabilities in the 2017 IRP capacity contribution analysis, the effective capacity contribution of this resource is 4.2 MW. Because the Company's loss of load probability is higher in the summer than other periods, the expected output during the summer has a larger impact on the capacity contribution.

Q. Is it appropriate to limit deferral of renewable resources used to meet system load to QFs of the same type?

A. Yes. The wind, solar, and geothermal resources identified in the 2017 IRP preferred portfolio are components of the least-cost, least-risk portfolio of resources needed to meet system load over time. The IRP preferred portfolio analysis does not include any

[6] 2017 IRP. Volume II. Appendix N: Wind and Solar Capacity Contribution Study. www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf.

[7] Brigham Young University – Idaho (BYU – Idaho). Please refer to: www.puc.idaho.gov/fileroom/cases/elec/PAC/PACE1708/20170712APPLICATION.PDF.

special obligations to acquire renewable resources or include any value for renewable attributes, and only accounts for the contribution of their operating characteristics to the composition and dispatch of the Company's portfolio of resources. The IRP analysis does assume that the Company would retain title to the Renewable Energy Credits ("RECs") associated with these renewable resources on behalf of its retail customers. Thus, labeling resources as "renewable" is not relevant to the composition of the preferred portfolio. Instead, the renewable resources in the IRP preferred portfolio were selected based on their specific operating characteristics. Limiting deferral to QFs of the same type helps ensure reasonable alignment between the operating characteristics of a QF and the preferred portfolio resources it is assumed to defer, which in turn helps ensure that the least-cost, least-risk outcomes achieved by the preferred portfolio are maintained.

Q. Please describe how the operating characteristics of different types of renewable resources vary.

A. The Company's 2017 IRP preferred portfolio ensures that each load bubble can meet the specified planning reserve margin of 13 percent, inclusive of imports of excess resources from other transmission areas.[8] Imports are restricted to the firm transmission rights between each area. The GRID model does not enforce the planning reserve margin requirements by transmission area, and the Company's forecast of avoided energy costs allows for displacement of wind and solar resources from across the system with only limited restrictions.

[8] A "load bubble" refers to an area that is assumed to have sufficient transmission capability within it such that all loads within the area can be reliably served by resources anywhere within the area or by transfers to any point within the area.

As an example, replacing wind resources that generate more in the winter with solar resources that generate more in the summer is likely to result in periods when transmission prevents delivery of resources to the locations where they are needed. Daily and seasonal shapes of solar and wind resources are complementary and can make better use of limited transmission resources than either resource on its own.

Wind and solar resources also exhibit significant variation both within the hour and over multiple hours. While the cost of maintaining flexible capacity within the hour is included in the IRP analysis, the cost of adjusting the Company's resource balance to accommodate solar and wind ramping has not been fully quantified. The Company's optimization models determine least-cost market transactions to balance the load net of solar and wind in each hour independently.

Operationally, the Company must rely on a combination of day-ahead block products and a limited supply of hourly transactions—often at unfavorable prices, with a tendency toward high prices when the Company is purchasing and low prices when the Company is selling. Renewable QFs will exacerbate these costs if their variations are correlated with other resources already in the Company's portfolio or with resources across the broader region, particularly as it becomes increasingly integrated via the Energy Imbalance Market. Deferring like renewable resources thus ensures that the forecast of avoided cost prices for a particular QF project maintains a comparable risk profile to the IRP preferred portfolio.

Q. Why is a change to the PDDRR methodology particularly appropriate at this time?

A. Wind and solar resources are both part of the Company's 2017 IRP Update preferred portfolio, representing the company's least-cost, least-risk plan to serve system load. Moreover, the 2017 IRP Update preferred portfolio no longer includes a thermal resource to use as a proxy under the approved methodology.

Q. How would displacement of renewable resources using the PDDRR methodology work?

A. Under the PDDRR methodology, it is assumed that QFs partially displace the next major renewable resource of the same type in the IRP preferred portfolio, based on equivalent capacity contributions as determined using the methodology in the IRP. Or, if no renewable resources of the same type remain in the IRP preferred portfolio, QFs partially displace the next major thermal resource in the IRP preferred portfolio, again based on their capacity contribution. While the GRID model can reasonably account for the differences in value between resources in two geographic locations, to maintain a consistent load and resource balance, it is important to maintain the total effective capacity contribution identified in the preferred portfolio.

Based on the capacity contribution study prepared for the 2017 IRP and used in the 2017 IRP Update analysis, each MW of east-side tracking solar resources is estimated to provide approximately 92 percent of the capacity provided by each MW of west-side tracking solar resources.[9] As a result, a 50 MW Wyoming tracking solar QF could defer 50 MW of an east-side tracking solar resource from the IRP preferred portfolio or 46 MW of a west-side tracking solar resource. The same capacity contribution study indicates that an east-side wind resource provides approximately

[9] East Tracking Solar: 59.7%. West Tracking Solar: 64.8%. 59.7% / 64.8% = 92%.

134 percent of the capacity provided by each MW of west-side wind.[10] Consequently, a 50 MW Wyoming wind QF could defer 50 MW of an east-side wind resource from the IRP preferred portfolio or 67 MW of a west-side wind resource. If no IRP renewable resources of a given type remain, pricing would revert to partially displacing the next thermal resource adjusted for the capacity contribution of the QF, or to displacing FOTs.

Q. What wind resources are available to be deferred by wind QFs?

A. The 2017 IRP Update preferred portfolio includes 1,311 MW production tax credit-eligible Wyoming wind resources added by the end of 2020. Of this, 1,150 MW have been committed at this time and are no longer considered deferrable. The remainder (Uinta Wind) was not approved by the Utah and Wyoming Commissions and has been removed and replaced by FOTs through 2029 and proxy wind resources in a comparable location starting in 2030. The same treatment has been applied to wind contracts assumed in the 2017 IRP Update load and resource balance that have not been approved. All of the replacement resources are deferrable. After accounting for these adjustments, the next deferrable wind resource is in 2030.

Q. What solar resources are available to be deferred by solar QFs?

A. Since the 2017 IRP Update was prepared, the Company executed power purchase agreements ("PPAs") with six solar resources totaling 437 MW of nameplate capacity and has terminated two solar QF PPAs with 17 MW of nameplate capacity. In addition, PacifiCorp's June 2018 load forecast includes incremental loads that are contingent upon the concurrent addition of renewable resources. To account for this, proxy

[10] East Wind: 15.8%. West Wind: 11.8%. 15.8% / 11.8% = 134%.

renewable resources sufficient to meet the requirements embedded in the load forecast have been included in the queue of committed resources. After accounting for these adjustments, the next deferrable solar resource is in 2030.

Q. How do the results under the proposed Schedule 38 methodology differ from the approved methodology?

A. At this time, the proposed change to the Schedule 38 methodology only impacts solar QFs, switching from deferral of thermal resources (of which there are none in the current preferred portfolio) under the approved methodology to deferral of solar resources under the proposed methodology. As shown in the table below, the proposed prices for solar resources are higher than under the current methodology, while baseload and wind prices are unchanged. The levelized price over the proposed seven-year contract term is also shown.

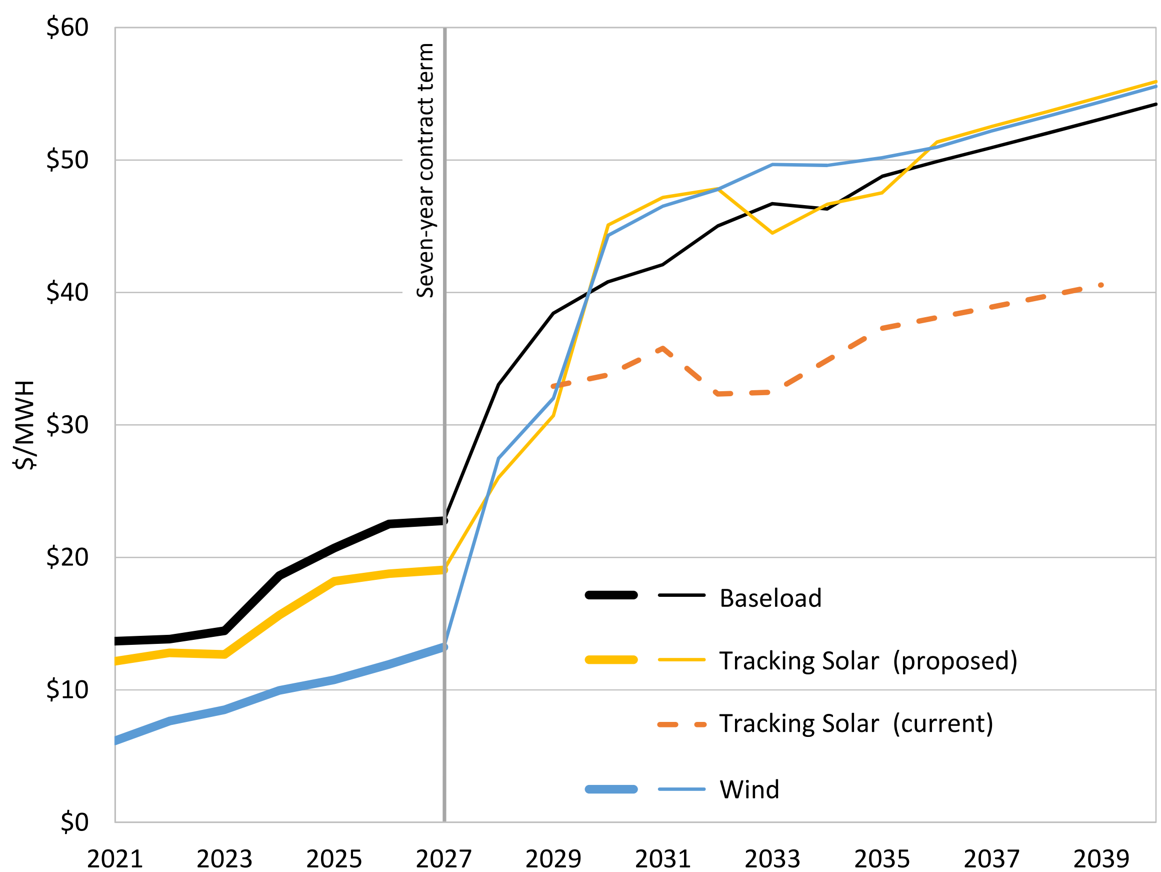
Table 2: Summary of Schedule 38 Avoided Cost Prices

Nominal Levelized Prices beginning 2021 @ 6.91% Discount Rate			
	Current Method	Proposed Method (20 year term)	Proposed Method (7 year term)
Baseload	31.01	31.01	17.61
Wind	27.18	27.18	9.44
Tracking Solar	24.49	29.70	15.25

Q. What drives the reduction in prices when transitioning from a 20-year term to a seven-year term?

A. As shown in Figure 1, avoided costs over the next few years are relatively low. Avoided costs rise significantly in 2028-2030, coincident with assumed retirements of the Dave Johnston and Naughton coal plants, along with Jim Bridger unit 1. Forecasts become increasingly uncertain the further into the future they are projected, and this is particularly true when considering the magnitude of the resources being added to compensate for these assumed retirements. As a result, the IRP preferred portfolio is likely to evolve significantly over the next few years. Even if the Company ultimately secures resources similar to the IRP preferred portfolio, the cost and operating characteristics of those resources may vary widely from the current assumptions. The option to modify procurement to provide greater customer benefits and/or lower cost in light of new information is valuable. If QFs receive 20-year contracts based on current assumptions, customers will be locked into those rates and will lose the opportunity to be served with more cost-effective resource options.

Figure 1: Schedule 38 Avoided Cost Pricing



SCHEDULE 37 METHODOLOGY

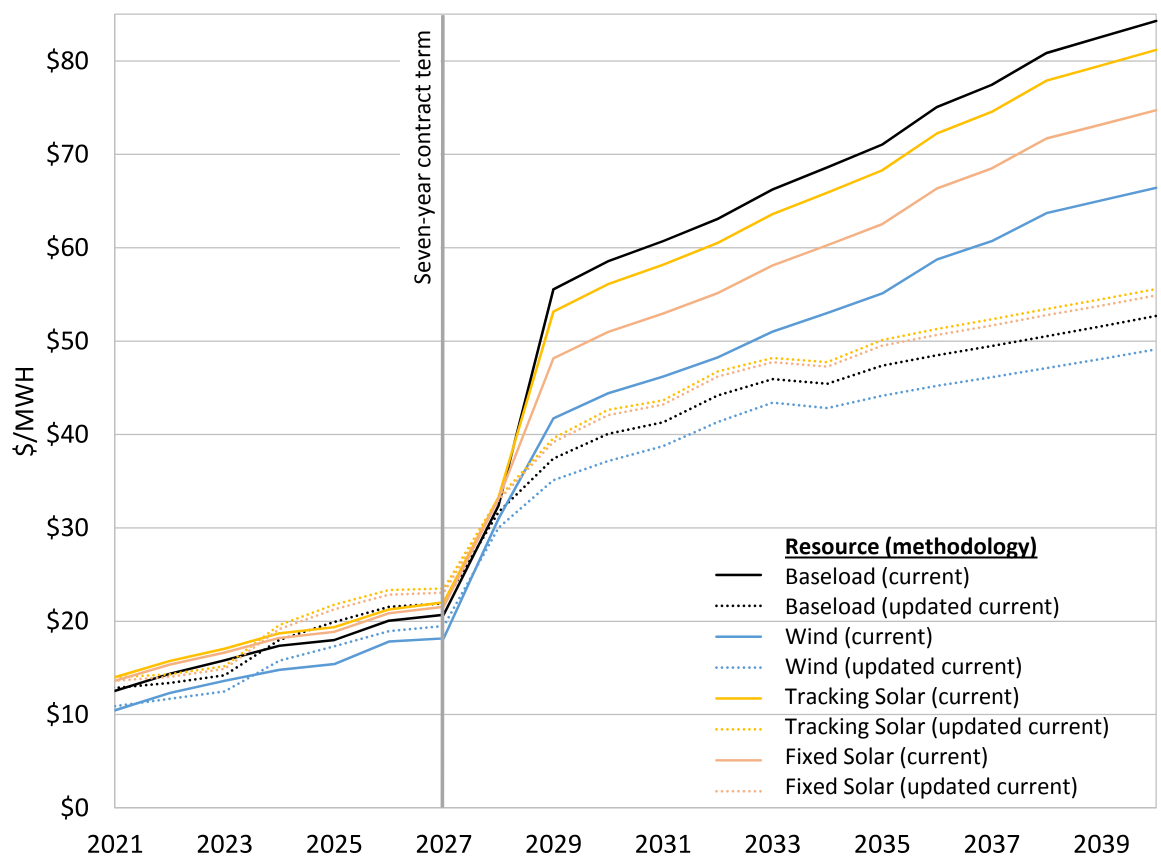
Q. Please describe the current Commission-approved method for calculating avoided costs for small QFs qualifying for published prices under Schedule 37.

A. Under the current Schedule 37 methodology, sufficiency period avoided costs are calculated using two GRID model simulations. The first simulation does not include any new QF resources. The second simulation includes an additional 50-MW baseload Wyoming QF resource at zero cost. The difference in net power costs between the two GRID runs divided by the energy produced by the QF resource determines the avoided energy cost. The deficiency period begins coincident with the next deferrable major thermal resource identified in the Company's most recent IRP or IRP Update preferred portfolio. Avoided costs during the deficiency period do not rely upon the GRID model, and are instead equal to the fixed and variable costs of a proxy resource, currently a combined cycle combustion turbine ("CCCT") plant. The combination of the avoided energy and capacity costs described above are reflected in a volumetric avoided cost price for each resource type included in Schedule 37.

Q. Does the current Schedule 37 methodology adequately account for the avoided costs of different resource types?

A. No. Figure 2 shows the current Commission-approved Schedule 37 prices and prices under the current methodology, after accounting for the Company's current Official Forward Price Curve, the preferred portfolio from the 2017 IRP Update, and contract changes since the 2017 IRP Update was prepared. The updated prices under the current Schedule 37 methodology have a smaller increase in the long term—reflecting the absence of any deferrable proxy thermal resources in the 2017 IRP Update preferred portfolio. The current methodology produces only four avoided energy values per year, for HLH and LLH periods in summer and winter, and does not account for any variations in either resource output or avoided cost within those periods. As a result there is very little variation between resources, and avoided cost prices move largely in lock-step over time, as the expected proportion of a resource's output in each period is constant.

Figure 2: Avoided Cost under the Commission-Approved Schedule 37 Methodology



Q. Is the current Commission-approved method the same as that used to calculate non-standard avoided costs under Schedule 38?

A. No. Non-standard avoided costs for large QFs under Schedule 38 are calculated using the PDDRR method as described above. The methods are similar in that both use the

GRID model to determine avoided costs during the sufficiency period and both include capacity costs in the deficiency period. As proposed, the PDDRR method differs in that it allows for deferral of cost-effective “like” renewable resources identified in the Company’s IRP preferred portfolio. PDDRR method also uses a combination of the GRID model to determine energy costs and partial displacement of specific IRP preferred portfolio resources to determine capacity costs during the deficiency period, rather than basing avoided costs solely on proxy CCCT capacity and energy costs. Specifically, the current Schedule 37 methodology accounts for the fuel costs of the proxy resource, but does not account for the difference in the value of the energy from the dispatchable proxy resource and the value of the energy from a QF resource. Furthermore, the PDDRR method accounts for the specific characteristics of a proposed QF and a proxy resource, including its geographic location and any transmission constraints, and prices are prepared for individual QF projects using project-specific generation profiles rather than providing the same published prices for all QFs. Applying the Schedule 38 pricing methodology to generic Wyoming QF resources of each QF type included in Schedule 37 better accounts for the resource-specific characteristics and signed contracts since the IRP preferred portfolio was developed.

Q. Can the PDDRR methodology used under Schedule 38 be used for Schedule 37?

A. Yes. The Company’s Schedule 37 tariff currently includes standard prices for four resource types: baseload, fixed solar, tracking solar, and wind. Rather than using a single avoided energy value based on a baseload resource, specific PDDRR pricing can be calculated for each of the four resource types. Rather than using a CCCT as the proxy for all QF resource types, under the proposed PDDRR methodology, QFs displace cost-effective "like" renewable resources identified in the Company's 2017 IRP Update preferred portfolio.

Q. What is the impact of switching to the PDDRR methodology for Schedule 37?

A. Table 3 summarizes the Schedule 37 avoided cost prices for all resource types under the proposed PDDRR methodology as well as the current and updated prices under the current Schedule 37 methodology. Figures 3 and 4 show the variation in prices over time under the proposed PDDRR methodology and updated prices under the current Schedule 37 methodology.

The proposed prices for baseload resources are higher than the updated prices under the current methodology, reflecting the value of deferring FOTs in addition to avoided energy costs. The proposed prices for wind and solar resources are lower than under the current methodology, reflecting the lower energy value of wind and solar resources relative to the baseload avoided energy cost applied in the current methodology. Both wind and solar QFs have output that is correlated with the wind and solar resources that are already in the Company's portfolio.

Table 3: Summary of Schedule 37 Avoided Cost Prices

Nominal Levelized Prices beginning 2021 @ 6.91% Discount Rate				
	Current Method	Updated Current Method	Proposed Method (20 year term)	Proposed Method (7 year term)
Baseload	40.09	30.12	31.01	17.61
Wind	32.05	27.66	27.18	9.44
Fixed Solar	36.96	31.57	27.00	14.06
Tracking Solar	39.64	32.02	29.70	15.25

Figure 3: Schedule 37 Avoided Cost Pricing for Baseload and Wind Resources

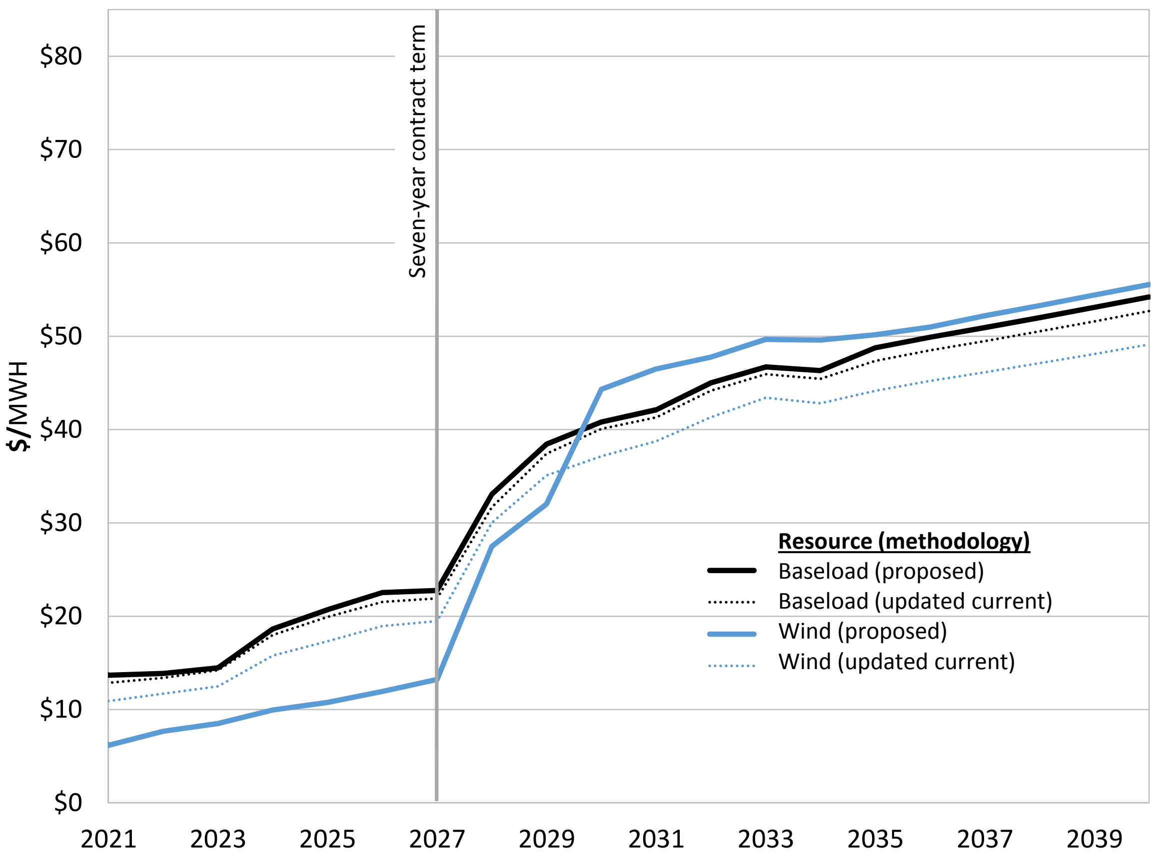
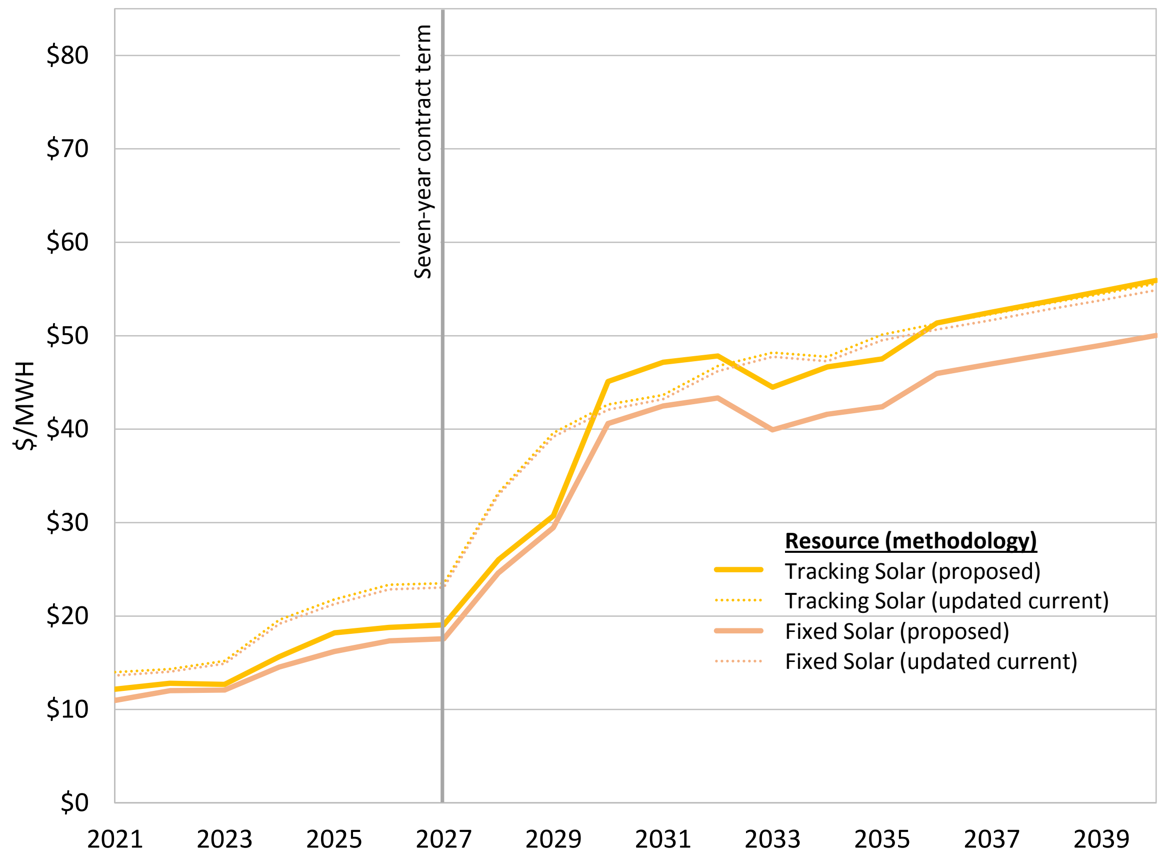


Figure 4: Schedule 37 Avoided Cost Pricing for Solar Resources



Q. Do you have any other proposed changes to Schedule 37 related to the change to the Schedule 38 methodology?

A. Yes. Since the Schedule 37 prices will be tied to the most recently filed IRP or IRP Update preferred portfolio, it is appropriate to update prices annually, following the filing of a new preferred portfolio. Annual updates will also help ensure prices accurately reflect avoided costs by incorporating other changes, for instance to contracts, loads, or market prices.

Q. What do you conclude with regard to the methodology for determining avoided cost pricing under Schedule 37?

A. The PDDRR methodology better captures the specific operational characteristics of different resource types and the aggregate effects on the Company's system than the Schedule 37 methodology currently in place. Adopting the PDDRR methodology for Schedule 37 avoided cost pricing is thus more consistent with the customer indifference standard.

ON-PEAK AND OFF-PEAK DEFINITIONS

Q. What are the current definitions of on-peak and off-peak hours under Schedule 37 and as typically applied under Schedule 38?

A. On-peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time ("PPT") Monday through Saturday, excluding North American Electric Reliability Corporation holidays. All hours other than on-peak hours are considered off-peak hours.

Q. What is the basis for the current definitions of on-peak and off-peak?

A. The current on-peak definition is consistent with the typical HLH and LLH standard products that have been in place for many years. Most of the Company's forward, balance of month, and day-ahead transactions are for either HLH, LLH, or all-hour products, though limited transactions occur for other products such as super peak (12:00 p.m. to 8:00 p.m. PPT).

Q. What do you propose as an alternative?

A. In the summer, defined as June through September, on-peak hours are defined as 3:00 p.m. to 10:00 p.m. PPT. In the winter, defined as October through May, on-peak hours are defined as 5:00 a.m. to 8:00 a.m. in the morning and 5:00 p.m. to 11:00 p.m. at night, again in PPT. The proposal does not differentiate between weekdays, weekends, and holidays. All hours other than on-peak hours are considered off-peak hours.

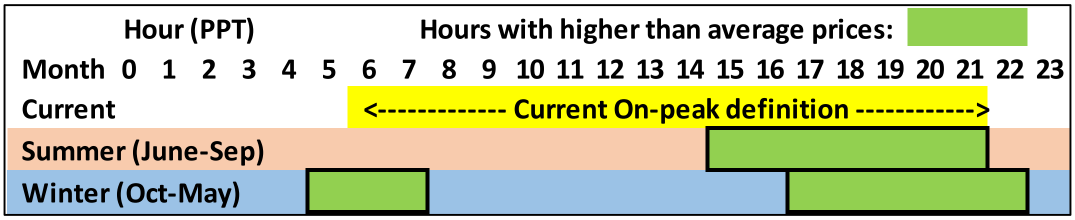
Q. Why is this proposal an improvement?

A. Under the current methodology, shaping between on-peak and off-peak is based on the ratio of Palo Verde HLH and LLH forward prices. For 2019, HLH prices are 68 percent higher than LLH prices in the summer, and only 16 percent higher than LLH prices in the winter. In contrast, based on the hourly Palo Verde market prices used to calculate avoided costs in the GRID model, the proposed on-peak definition results in prices that average 114 percent higher than off-peak prices in the summer, and 93 percent higher than off-peak prices in the winter. The greater difference between on-peak and off-peak under the proposal indicates that it is more accurately categorizing high price and low price periods.

Q. How were the proposed on-peak and off-peak definitions determined?

A. Those hours in which the average price is greater than the monthly average for all hours are considered on-peak, while those hours in which the average price is less than the monthly average for all hours are considered off-peak. These calculations are based on forecasted hourly prices for 2019 as contained in the GRID model, which reflect the current Official Forward Market Price and hourly market price scalars. The monthly results are then aggregated to produce an on-peak definition that is specific to summer and to winter. The resulting definitions are shown in Figure 5 below. While May is considered part of the summer under current Schedule 37 definitions, it is better aligned with the winter on-peak definition than the summer definition.

Figure 5: On-peak and Off-peak Definitions



Q. What are the primary differences in the proposed on-peak definition relative to the current HLH definition?

A. The most important difference is the elimination of hours during the middle of the day, when the sun is shining and net load requirements are relatively low. Hours are added at the beginning and end of the on-peak period in the winter only, indicating that these time frames are the most constrained of what was previously considered off-peak.

Q. Does the change in the on-peak and off-peak definitions impact a given QF's expected total avoided cost payments under the Schedule 38 methodology?

A. No. Under the Schedule 38 methodology, the total expected avoided cost payments are the same, regardless of the on-peak and off-peak definition used. Avoided costs are calculated within the GRID model for every hour, and reflect the expected QF output in each hour, so the on-peak and off-peak definition is irrelevant in that part of the analysis. The total avoided costs are then spread among on-peak and off-peak periods, but since it is based on the QF's expected output specific to each period, the total expected payment is the same, whatever periods are selected.

Q. If the total expected avoided cost payment remains the same, why is a change necessary?

A. A QF's output will vary from the forecasted resource profile, resulting in more generation than expected in some periods, and less generation than expected in others.

If a QF delivers more during a part of on-peak with a relatively high value, it provides greater benefits to customers than if a QF delivers during a part of on-peak with a relatively low value. Ideally, the value throughout on-peak should be as uniform as possible, so that whenever it delivers in that period, the benefits are comparable. By removing on-peak hours with relatively low value, the average value reflected in the on-peak price increases. Because QFs have an incentive to deliver in hours when their prices are highest, high prices in high value periods helps ensure retail customer indifference.

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission adopt the following changes to Schedule 37 and Schedule 38:

1. Modify the PDDRR methodology currently used for Schedule 38 as previously described, allowing for "like-for-like" deferral of renewable resources.
2. Reduce in the maximum contract term under Schedule 38 to seven years.
3. Approve a revised Schedule 37 incorporating the following:
    a. Prices based on the PDDRR methodology used for Schedule 38.
    b. A maximum contract term of seven years.
    c. The proposed changes to the on-peak and off-peak definitions.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED CONTRACT TERM OF PURPA POWER PURCHASE AGREEMENTS WITH QUALIFYING FACILITIES	)))))))))	DOCKET NO. 20000-___-EA-18 (RECORD NO. _____)

AFFIDAVIT, OATH AND VERIFICATION

Daniel MacNeil (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is a Resource and Commercial Strategy Adviser for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his official capacity as Resource and Commercial Strategy Adviser.

Further Affiant Sayeth Not.

Dated this 31st day of October, 2018

Daniel MacNeil
Resource & Commercial Strategy Adviser
825 NE Multnomah Ave, Ste 600
Portland OR, 97232
503-813-5523

STATE OF Oregon)
) SS:
COUNTY OF Multnomah)

The foregoing was acknowledged before me by Daniel MacNeil on this 31st day of October, 2018. Witness my hand and official seal.

Official Stamp
Anne Kohls
Notary Public - Oregon
Commission No. 966746
My Commission Expires September 17, 2021

Anne Kohls
Notary Public

My Commission Expires: Sept. 17, 2021