ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 310
Salt Lake City, Utah 84114

August 17, 2017

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84111

Attn: Gary Widerburg
Commission Secretary

RE: Docket No. 17-035-T07 - In the Matter of Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities
Docket No. 17-035-37 – In the Matter of Rocky Mountain Power's 2017 Avoided Cost Input Changes Quarterly Compliance Filing

In its July 27, 2017 order, in the above referenced matters, the Public Service Commission of Utah ("Commission") directed Rocky Mountain Power (the "Company") to file its Direct Testimony on August 17, 2017. The Company hereby provides for filing its Direct Testimony as directed by the Commission. The Direct Testimony consists of the testimony, appendix, and workpapers of one witness. The Company will post its confidential workpapers to the Commission's secure website.

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred)	datarequest@pacificorp.com bob.lively@pacificorp.com
By Regular Mail	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

Informal inquiries may be directed to Bob Lively at (801) 220-4052.

Very truly yours,

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

Rocky Mountain Power
Docket No. 17-035-T07/37
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Daniel J. MacNeil

August 2017

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.

PURPOSE OF TESTIMONY AND RECOMMENDATION

Q. What is the purpose of your testimony?

A. My testimony provides support for the Company's June 21, 2017 Avoided Cost Input Changes Quarterly Compliance Filing[1] (2017.Q1 Filing) in which four routine updates

[1] 2017 Avoided Cost Input Changes – Quarterly Compliance Filing. Docket No. 17-035-37. Available at: https://psc.utah.gov/2017/06/22/docket-no-17-035-37/.

and two non-routine updates were identified. My testimony also provides support for the adoption of the same methodology implemented under Schedule 38 to determine published pricing for Schedule 37, Avoided Cost Purchases from Qualifying Facilities, reiterating the Company's proposal from Docket 17-035-T07.

Q. Please describe the Company's 2017.Q1 Filing and challenges to the filing.

A. The 2017.Q1 Filing identified four routine updates and two non-routine updates. Parties have challenged three of these updates, specifically:

- Routine updates associated with the 2017 IRP, including updates to the sufficiency period/deficiency period, deferrable resources, and the preferred portfolio;
- A non-routine update to renewable energy credit ("REC") ownership; and
- A non-routine update to post-IRP resource expansion plan pricing.

Q. How is your testimony organized?

A. My testimony first describes the currently approved and effective Proxy/Partial Displacement Differential Revenue Requirement ("Proxy/PDDRR") methodology for determining non-standard avoided costs under Schedule 38. In response to parties that have challenged the Company's routine updates, I next describe how the Proxy/PDDRR methodology is implemented based on the 2017 IRP preferred portfolio and why substantial changes are unnecessary. In particular, my testimony demonstrates that the current Proxy/PDDRR methodology with 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.

My testimony next provides justification for the two non-routine methodology updates. For instance, when customers pay a QF based on the costs of a renewable resource, they should not be expected to forego the benefits of RECs they otherwise would have received from that resource. Likewise, it is unreasonable to expect the GRID model to produce a reasonable forecast of avoided energy costs without including a realistic least-cost, least-risk portfolio of resources necessary to meet the target planning reserve margin.

Finally, 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, reiterating the Company's proposal from Docket 17-035-T07. My testimony demonstrates that the Proxy/PDDRR methodology better captures the specific operational characteristics of different resource types and is more consistent with the customer indifference standard.

<u>PROXY/PDDRR METHODOLOGY</u>

Q. Which parties challenged the Company's routine updates related to the 2017 IRP?

A. Utah Clean Energy ("UCE") and Sustainable Power Group ("sPower") both challenged the Company's implementation of updates associated with the 2017 IRP, including updates to the sufficiency period/deficiency period, deferrable resources, and the preferred portfolio.

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

A. The Proxy/PDDRR methodology used to determine avoided costs was first established by the Commission's October 31, 2005 order in Docket No. 03-035-14. The Proxy/PDDRR methodology is used to forecast avoided fixed costs from a proxy resource and to forecast avoided energy costs associated with incremental generation from a particular qualifying facility ("QF") project. Avoided fixed costs include avoided capital costs, which is based on the capital cost of a proxy resource expressed as 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 includes 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 Proxy/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 Generation and Regulation Initiative Decision Tools ("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 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 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.[2,3]

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

A. The Proxy/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 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

[2] 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").

[3] See, e.g., In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities, Docket No. 15-035-53, January 7, 2016 Order at 16-18; In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts, Docket No. 12-035-100, December 20, 2012 Order at 13-14 (noting that customer indifference is a "primary" Commission concern in implementing PURPA).

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

Q. Has the Proxy/PDDRR methodology been modified since the 2005 Order?

A. Yes. In Docket No. 12-035-100, the Company proposed modifications to the Proxy/PDDRR methodology applicable to avoided cost price projections for renewable resources ("2012 Docket"). The proposed modifications included:

- The capacity contribution applied to intermittent renewable resources.
- The inclusion of integration costs that reflect the need to manage the uncertainty and variability of renewable resources.
- The proxy resource used to establish avoided fixed costs for renewable resources.
- The ownership of RECs generated by renewable resources.

Adjustments to account for the capacity contribution and integration costs in the Proxy/PDDRR methodology were approved in the 2012 Docket. The Company's IRP process now routinely includes studies of capacity contribution and integration costs and the results of those studies are incorporated in the Proxy/PDDRR methodology. These adjustments have not been disputed by parties.

Regarding the proxy resource to be used to determine avoided costs, the Commission approved a methodology for deferring cost-effective renewable resources identified in the Company's IRP. Specifically, when the Company's IRP preferred portfolio includes renewable resources to meet system load 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 the Company's IRP preferred portfolio does not include a renewable resource as part of its plan to meet system load that is the same type as a QF, avoided capacity costs are based on the capital costs of the next deferrable thermal resource in the IRP preferred portfolio. Since the 2017 IRP now includes renewable resources as part of the Company's plan to meet system load, this methodology has become relevant for the first time. The first section of my Proxy/PDDRR testimony provides support for continuing to limit deferral to renewable resources used to meet system load of the same type, while the next section of my Proxy/PDDRR testimony provides the reasons why Utah QFs should not be allowed to defer the 2021 Wyoming wind resources included in the 2017 IRP preferred portfolio.[4]

The Commission's August 16, 2013 Order in the 2012 Docket also allowed QFs to retain ownership of the RECs generated by their facilities unless otherwise negotiated by contract. In its October 4, 2013 Clarification Order in the 2012 Docket, the Commission found that, based on the evidence in the record, no renewable QF was scheduled to defer a renewable resource used to meet system load in the near future, and that at that time it was unnecessary to further clarify REC ownership.[5] Since the 2017 IRP now includes renewable resources as part of the Company's plan to meet

[4] The 2021 Wyoming wind resources are assumed have a December 31, 2020 in-service date to ensure the assumed tax benefits are achieved.

[5] In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts, Docket No. 12-035-100, October 4, 2013 Order at 6-8.

system load, this question is now relevant, and is addressed in the second section of my testimony.

DEFERRAL OF LIKE RENEWABLE RESOURCES

Q. What is the fundamental premise of the Proxy/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 does the Company interpret renewable resources of the same type?

A. The "type" is meant to reflect the operational characteristics of the QF on the Company's system, not the specific technology of the resource identified in the preferred portfolio. The 2017 IRP preferred portfolio includes 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 renewable 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. What resources from the 2017 IRP preferred portfolio are currently considered deferrable?

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

Thermal:

- 2029: Utah North simple cycle combustion turbine ("SCCT") (200 MW)
- 2030: Willamette Valley combined cycle combustion turbine ("CCCT") (436 MW)
- 2033: Dave Johnston SCCT (200 MW)
- 2033: Dave Johnston CCCT (477 MW)

Wind:

- 2031: Dave Johnston wind (85 MW)
- 2036: Goshen wind (774 MW)

Solar:

- 2028-2034: Yakima fixed tilt solar (240 MW)
- 2031-2036: Utah South single tracking solar (800 MW)

Geothermal:

- 2029: West geothermal (30 MW)

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 output, but its monthly expected output varies from 4.0 MW in September to 4.7 MW in December. When the monthly expected output 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. Do you have another example of a resource-specific capacity contribution based on the assumptions described above?

A. Yes. The Company has recently received indicative pricing requests for solar QFs that include battery storage. The addition of a battery allows a portion of the QF's generation to be shifted to periods with greater loss of load probability, increasing the

[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.

capacity contribution relative to a solar resource on its own. The capacity contribution of the combined solar and battery project is calculated using the methodology and loss of load probability data underlying the capacity contributions developed for the 2017 IRP. The analysis takes into account the solar resource's generation profile as well as the size, storage capacity, and efficiency of the battery. In one recent example, a developer proposed a solar project with battery capacity that was approximately half the size of the solar resource. The battery included five hours of storage capability and had assumed round-trip losses of 23.5 percent. Increasing battery size or storage capability increases the amount of generation than can be stored and made available in more beneficial periods. Similarly, reducing losses increases the amount of generation that can be made available later. The resulting capacity contribution for the project as a whole was 76.7 percent, compared to 59.7 percent for an east tracking solar resource without a battery.

Q. Does the Company continue to support limiting 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 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 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. 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.

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.

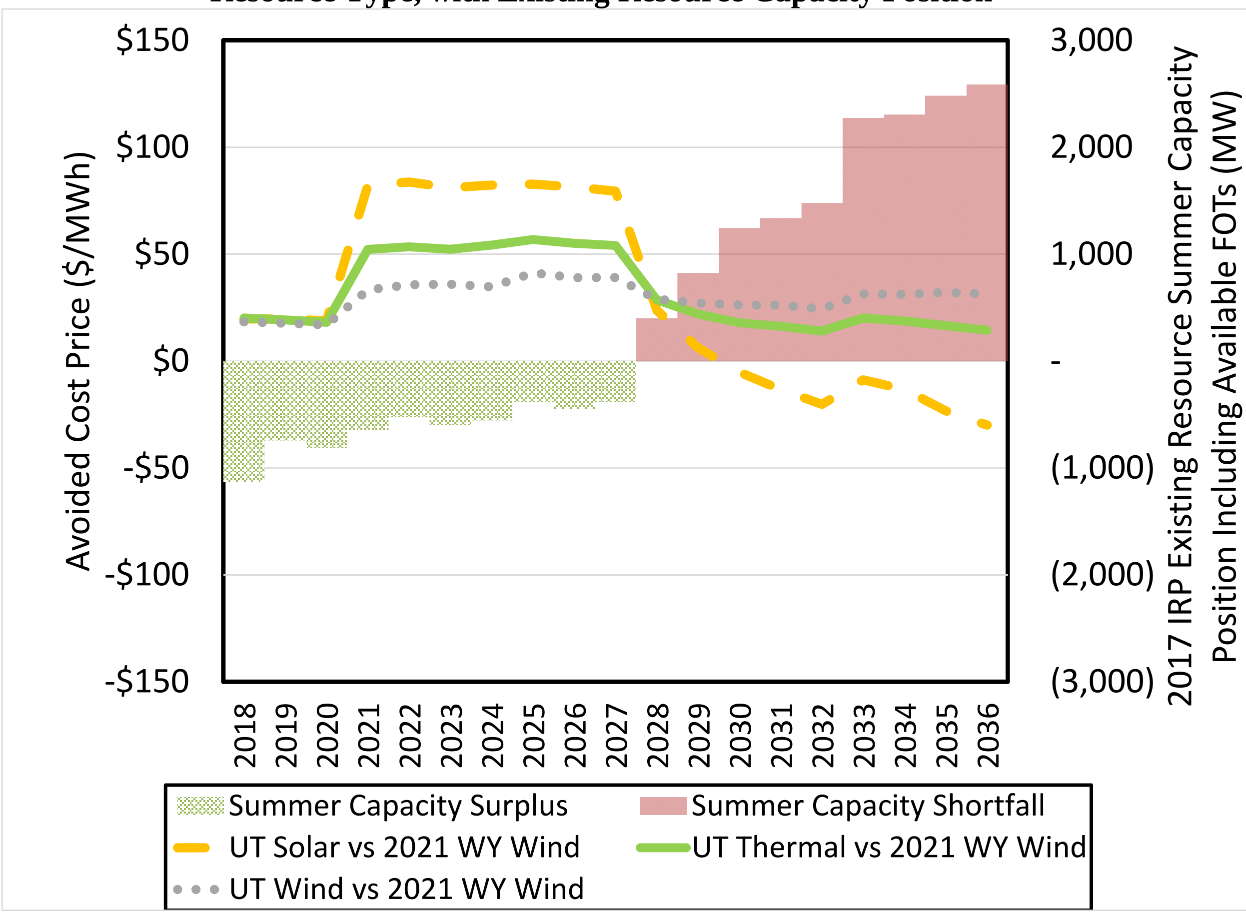
Wind and solar resources also exhibit significant variation both within the hour and over multiple hours. While the cost of maintaining flexible capacity within the hour is included in the IRP analysis, the cost of adjusting the Company's resource balance to accommodate solar and wind ramping has not been fully quantified. The Company's optimization models determine least-cost market transactions to balance the 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. Can you provide more detail on the inconsistencies when deferral of varying renewable resource types occurs?

A. In response to REC data request 1.10 in Docket No. 17-035-T07, the Company prepared indicative avoided cost pricing for 10 MW wind, solar, and biomass resources, assuming those resources deferred capacity-equivalent amounts of the 2021 wind resource in the 2017 IRP preferred portfolio. Figure 1 shows the annual avoided cost results under the PDDRR methodology. The 2021 wind resource was selected to provide a sense of the range of variation in avoided costs over the course of the IRP forecast period and a QFs contract term, though the Company does not consider this resource to be deferrable, as discussed later in my testimony. On the right axis of Figure 1 is the Company's summer capacity position when only existing resources and available front office transactions ("FOTs") are considered (*i.e.*, not including any new resources), as identified in the 2017 IRP. The Company has surplus capacity through 2027, and a capacity shortfall starting in 2028.

Figure 1: Avoided Cost Assuming Deferral of IRP Wind Resources, by Resource Type, with Existing Resource Capacity Position



Q. Are the solar and biomass avoided cost prices shown in Figure 1 reasonably consistent with the Company's capacity needs and costs?

A. No. The discrepancy is most evident in the prices for a solar QF, which are extremely high and much higher than the Company's avoided cost through 2027, but drop precipitously in 2028 and become negative in 2030 when the QF would be required to pay the Company for each MWh it delivered to the Company's system. Faced with these avoided costs, a solar QF would be expected to elect a ten-year contract term through 2027, which does nothing to address the Company's capacity needs in 2028. Through 2027 existing resources and capacity available from FOTs are sufficient to meet the Company's summer capacity needs, so avoided capacity costs are expected to be low—at or below market prices, not significantly in excess of market prices.

Starting in 2028, FOTs are not sufficient to meet the Company's summer capacity needs and more expensive thermal and renewable resources are required, so a drop in avoided cost in this time frame is not reasonable. The effect for a biomass QF is of a smaller magnitude, but still reflects a nearly 50 percent reduction in avoided costs from 2027 to 2028.

Q. How do these avoided costs compare to cost assumptions for solar resources in the 2017 IRP?

A. The 2017 IRP included Utah solar resource options that were not selected as part of the preferred portfolio, indicating that lower-cost, lower-risk resource alternatives were available. The cost of a Utah tracking solar resource in the 2017 IRP was $57/MWh in 2021, rising at inflation to $65/MWh in 2027. This is well below the avoided cost of solar based on displacement of the 2021 wind resources shown in Figure 1, which are roughly $80/MWh in this same time frame. The fact that this resource was not selected as part of the 2017 IRP preferred portfolio indicates that actual avoided costs through 2027 are even lower.

Q. Why do these resources produce such significant variations in avoided cost?

A. Generally these variations reflect the relative quantity of capacity and energy provided by each of the QF resources. As shown in Table 1, wind resources provide the least amount of capacity relative to energy, while solar resources provide the most. The significant variation in the relative value of energy and capacity results in different resources being more valuable at different periods based on their overall characteristics.

Table 1: Capacity to Energy Ratios

Resource	Capacity Factor	Capacity Contribution	Capacity to Energy Ratio
Utah Solar	31.1%	59.7%	1.92
Utah Biomass	100.0%	100.0%	1.00
Utah Wind	31.0%	15.8%	0.51
2021 IRP Wind	41.2%	15.8%	0.38

Q. Is there a place for resources producing predominantly energy, rather than capacity?

A. Yes. Utility systems have traditionally included both peaking units built primarily for capacity, and baseload units built for energy production. Solar units share many characteristics with peaking units because they have relatively high all-in cost per unit of output, but greater contribution to serving peak requirements. On the other hand, wind units generally have a lower cost per unit of output, along with a lower contribution to serving peak requirements. Coal units have traditionally provided much of the energy on the Company's system and the significant coal plant retirements assumed in the 2017 IRP preferred portfolio result in a greater need and associated value from low-cost energy resources such as wind when compared to solar resources.

Q. Are there significant differences between the generation of the QF resources and the 2021 IRP wind they could theoretically displace as described above?

A. Yes. Because a 10 MW Utah solar QF provides capacity equivalent to 37 MW of 2021 IRP wind and has a lower capacity factor, the Company would lose 4.9 MWh of 2021 IRP wind generation for each MWh of generation received from a solar QF. Similarly a 10 MW Utah thermal QF provides capacity equivalent to 63 MW of 2021 IRP wind and has a higher capacity factor. The higher capacity contribution partially offsets the capacity deferral, but the Company still loses 2.6 MWh of generation from the 2021 IRP wind resource for each MWh of generation received from a thermal QF. Finally, a Utah wind QF produces 25 percent less generation than the 2021 IRP wind resource it could theoretically displace. As a result, the Company will have significantly greater dependence on thermal and market resources if solar or biomass QFs are allowed to displace wind resources. While the Proxy/PDDRR methodology and GRID model cannot reflect a comprehensive reoptimization of the Company's resource portfolio, deferral of renewable resources of the same type has the greatest potential to maintain the least-cost, least-risk characteristics of the preferred portfolio.

NEW WIND AND TRANSMISSION

Q. Should the wind and transmission resources identified in the Company's 2017 IRP preferred portfolio be considered deferrable?

A. No. The 1,100 MW of new Wyoming wind resources eligible for the full value of production tax credits (PTCs) that are added in 2021 (as a proxy for a December 31, 2020 in-service date to ensure the assumed tax benefits are achieved) is tied to the Aeolus-to-Bridger/Anticline transmission line. The new wind and transmission associated with this project provides all-in economic benefits to the Company customers in all jurisdictions. Therefore, QF projects that do not interconnect with and/or use the Company's Wyoming transmission system (*i.e.*, Utah QFs) to deliver energy and capacity in this timeframe would not partially displace or defer any of the 1,100 MW of new wind associated with the project.

Q. Please describe the partial displacement methodology.

A. A 10 MW Utah tracking solar QF can defer 9.2 MW of a west-side tracking solar resource or 6.0 MW of a thermal resource from the IRP preferred portfolio.[8]

In both cases, 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. This captures the PURPA requirement that avoided costs should take into account the smaller capacity increments and the shorter lead times typically associated with capacity from QF projects.

Q. How does the partial displacement concept relate to the potential deferral of the 2021 Wyoming wind resources included in the 2017 IRP preferred portfolio?

A. Two characteristics of the 2021 Wyoming wind resources make them inappropriate to consider for capacity deferral. First, these resources cannot be deferred to a later date, as they would not qualify for the PTC after December 31, 2020. The loss of the PTC would eliminate many of the benefits associated with the 2021 Wyoming wind resources. And without those benefits, the Wyoming wind would not be part of the Company's least-cost, least-risk plan to reliably meet system load.

Second, the transmission line that enables interconnection of these resources to the Company's system cannot be reduced in size. Further, the transmission line and the new wind resources are mutually dependent upon one another. The new wind and transmission will be pursued so long as it provides benefits in excess of its costs. These characteristics show that resources outside of the area of the new transmission line

[8] East Tracking Solar: 59.7%. West Tracking Solar: 64.8%. 59.7% / 64.8% = 92%
Thermal Resource: 100%. East Tracking Solar: 59.7%. 59.7% / 100% = 60%.

would neither delay nor supplant the 2021 Wyoming wind resources in the 2017 IRP preferred portfolio.

Q. Does the expiration of the PTC create differences in deferral value when compared to other resources that are not eligible for the PTC?

A. Yes. For most resources, the real-levelized annual cost assumed in the IRP is fixed, so a plant built at a later date has the same real cost as a plant built today. Thus, if a QF defers a gas plant for five years, the gas plant can be built in year six at the same real-levelized cost that would have been incurred in year six if the QF had not deferred the gas plant for five years.

This is not the case for a PTC-qualifying wind resource, as wind resources that are placed in service by the end of 2020 will receive the full value of the PTC, whereas wind resources constructed at a later date will receive a reduced PTC value (or no value at all). As a result, if a QF defers a PTC-qualifying wind resource for five years beyond 2020, the real-levelized annual cost in year six will be higher than if they were built before the end of 2020. So a QF deferring the 2021 Wyoming wind resource in the IRP would leave customers with higher costs in the future than they would otherwise incur.

Q. Should the fact that the 2021 wind resources are renewable influence the determination of whether they are deferrable?

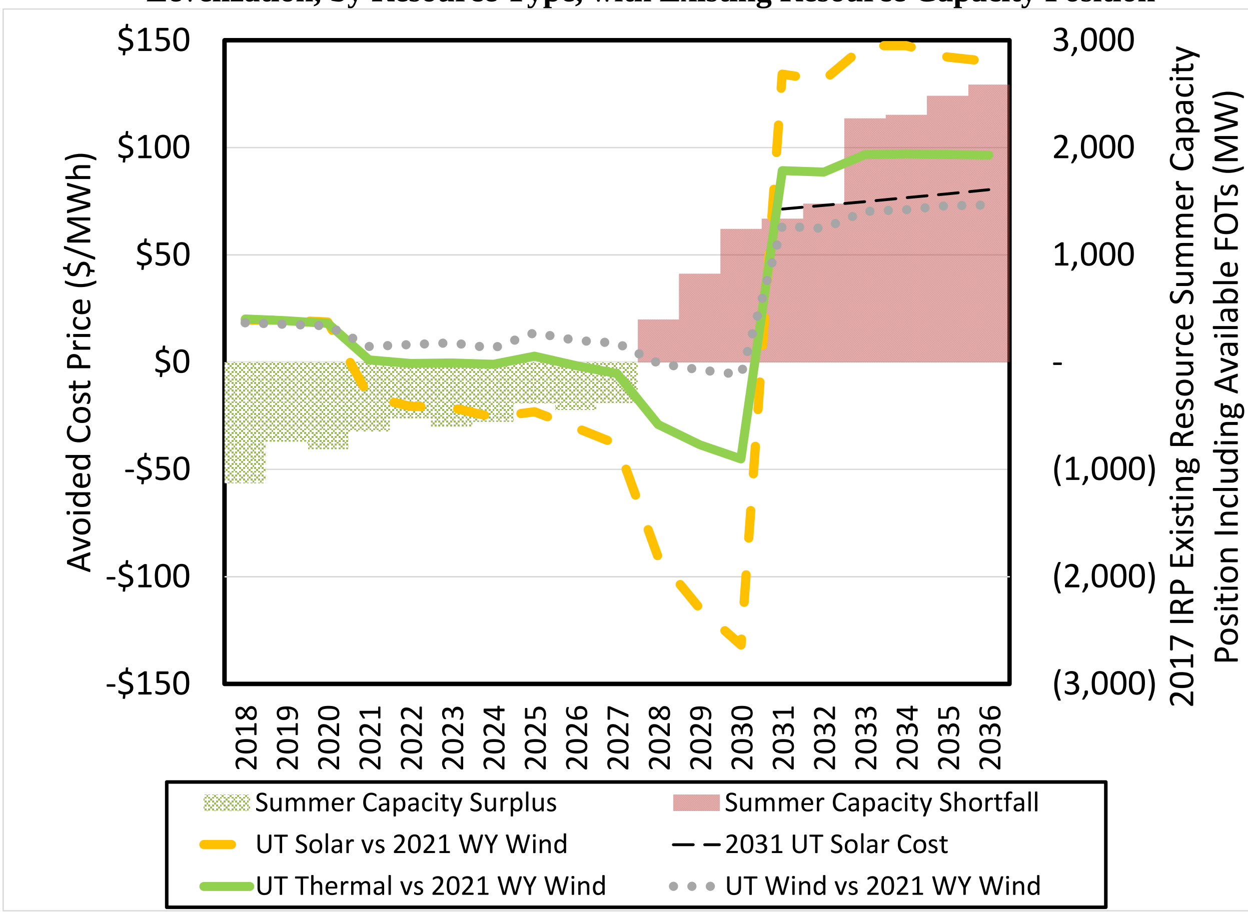
A. No. As previously discussed, the 2017 IRP preferred portfolio does not assign any additional value to renewable resources, simply for being renewable, relative to other resource options. As such, if capacity contribution is the only pertinent factor for determining resource deferral, the entire 2021 wind project could be deferred by 174 MW of baseload resources of any type, yet a baseload resource was not one of the least-cost, least-risk resources identified in the 2017 IRP preferred portfolio.

Q. Is there an alternative implementation of the Proxy/PDDRR methodology that better aligns with the time-sensitive nature of the PTCs which are driving the inclusion of the 2021 Wyoming wind resources in the 2017 IRP preferred portfolio?

A. Yes. The Proxy/PDDRR methodology forecasts real levelized avoided capacity costs based on a resource's capital cost and the life of the asset. Fixed and variable operations and maintenance costs and tax credits are also included on a real levelized basis. Under the current Proxy/PDDRR methodology, tax credits are spread over the life of the asset, and retail customers would lose all PTC benefits beyond the QF's contract term. In reality, PTCs associated with the 2021 Wyoming wind resources will be received in the first ten years of operation. Reflecting the PTC benefits in the years they are incurred significantly impacts the avoided cost prices a QF would receive.

Figure 2 shows that from 2021 through 2030, the avoided cost associated with thermal and solar QFs assumed to defer the 2021 wind resource is near zero or negative, while that for wind QFs is also very low. This is because the PTCs associated with the 2021 Wyoming resource counteract most of its real levelized capital cost in the first ten years of operation, so the output is nearly free, even before accounting for its energy value. As shown in Table 1, solar and thermal QFs have relatively low generation compared to a capacity equivalent amount of wind resources. Specifically, each MWh of solar generation must replace the energy benefits of 4.9 MWh of wind generation, while each MWh of thermal generation must replace the energy benefits of 2.6 MWh of wind generation. When Dave Johnston is assumed to retire at the end of 2027, the energy value of the 2021 Wyoming wind resources increases significantly. Because solar and thermal QFs must both replace several MWh of wind generation, this effect is amplified in their avoided cost prices.

Figure 2: Avoided Cost Assuming Deferral of IRP Wind Resources and No PTC Levelization, by Resource Type, with Existing Resource Capacity Position



Q. Do the avoided costs shown in Figure 2 for 2030 and beyond reflect the Company's avoided costs?

A. No. The 2017 IRP preferred portfolio includes a Utah solar resource starting in 2031. As shown in Figure 2, the cost of the IRP solar resource is well below the avoided cost for a solar QF that is assumed to defer 2021 Wyoming wind resources. Procuring a solar resource more than ten years in advance of the defined need in the preferred portfolio, and at costs in excess of the Company's resource options, does not accurately represent the Company's avoided costs.

Q. What do you conclude with regard to deferral of the 2021 Wyoming wind resource?

A. It is inappropriate to partially displace the 2021 Wyoming wind resource based on resource additions outside of the constrained area connected by the proposed transmission line. While removing the levelization of PTCs in the Proxy avoided capacity cost based on deferral of the 2021 wind resource better aligns with retail customer indifference, it still does not produce reasonable avoided costs, particularly for solar and thermal resources.

REC OWNERSHIP

Q. What is the first non-routine avoided cost input change proposed by the Company?

A. The Company's 2017.Q1 Filing proposed that, during the portion of a QF's contract in which it receives an avoided capacity payment based on deferral of a like renewable resource, the Company would own the RECs associated with that QF's output. Beyond the capacity payment associated with the proxy resource being deferred, no additional compensation would be paid for these RECs. During any portion of a QF's term when its avoided capacity costs are not based on the costs of a renewable resource, the QF will continue to be entitled to the RECs associated with its output, as is currently the case today.

Q. Which parties challenged this update?

A. The Division of Public Utilities ("Division"), UCE, and sPower all challenged the Company's REC ownership proposal.

Q. Has the Commission previously ruled on REC ownership under QF contracts?

A. Yes. As previously discussed, the Commission previously ruled in its October 4, 2013 Order in the 2012 Docket that RECs are retained by the QF unless otherwise provided for in a negotiated contract.

Q. What was the basis for the Commission's prior ruling?

A. The Commission found that the Company's position on REC ownership in its request for clarification in the 2012 Docket was not sufficiently developed in the record. Further, the Commission found that given the absence of renewable resources in the IRP Action Plan that could be deferred by a QF, having QFs retain RECs did not represent an existing, potential, or threatened violation of PURPA's ratepayer indifference standard at that time. Because the Company's preferred portfolio now includes solar and wind resources in its least-cost, least-risk plan to meet system load that can be deferred by QFs when forecasting avoided costs, it is appropriate to revisit this issue.

Q. What specific issue related to RECs did the Commission find to be insufficiently developed in the record in the 2012 Docket?

A. The Commission found that there was inadequate support in the record to conclude that the IRP assumes the Company keeps the RECs from any renewable resources that includes in its preferred portfolio that can be procured through specific actions outlined in the IRP action plan.

Q. Does the 2017 IRP assume the Company keeps the RECs associated with the cost-effective renewable resources identified in the preferred portfolio?

A. Yes. The RECs associated with new renewable resources are explicitly assumed to contribute to meeting RPS targets in the Company's western states.[9] While existing owned and contracted resources are sufficient to meet Utah's 2025 state target for renewable resources, Utah customers receive benefits from RECs that are not needed to meet their compliance obligations.

Q. What benefits would Utah retail customers receive from RECs associated with the cost-effective renewable resources identified in the preferred portfolio?

A. Action item 1d in the 2017 IRP action plan outlines two potential avenues by which Utah customers could benefit from RECs associated with new renewable resources. First, RECs could be reallocated to Oregon, Washington, or California for consideration to be determined among the Company's retail jurisdictions. Second, RECs can be sold to third-parties with the difference between REC revenues in Utah rates and actual REC sales revenues credited to or collected from Utah customers under Tariff Schedule 98.

Q. How would the Company's REC ownership proposal apply to the deferrable renewable resources in the 2017 IRP?

A. A wind QF that received pricing based on the deferral of the 2031 Wyoming wind resource would keep the RECs associated with its output through the end of 2030, while the Company would receive the RECs associated with the QF's output from 2031 through the end of its contract. A renewable thermal or baseload QF that received pricing based on the deferral of the 2029 geothermal resource would keep the RECs associated with its output through the end of 2028, while the Company would receive

[9] 2017 Integrated Resource Plan. Volume I. pages 240-241. Available online at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf.

the RECs associated with the QF's output from 2029 through the end of its contract. A 10 MW solar QF that received avoided cost pricing based on the deferral of 7 MW of 2031 solar resources and 3 MW of 2032 solar resources would keep all of its RECs through 2030, and 30% of its RECs in 2031. The Company would receive 70% of the RECs associated with the QF's output in 2031 and all of the RECs in 2032 through the end of the contract.

Q. Has the Company provided additional evidence here to justify and support the Company's proposal on REC ownership?

A. Yes. The 2017 IRP assumes that RECs associated with new renewable resources will be allocated among all retail jurisdictions. Utah ratepayers are thus entitled to any resulting benefits from those RECs. Assigning REC ownership to the Company during periods when a QF is being paid for capacity from a renewable resource of the same type in the preferred portfolio would ensure that Utah ratepayers are entitled to comparable quantities of RECs. This helps maintain the Utah ratepayer indifference between the renewable resource in the preferred portfolio and the QF resource. For the same reasons, if QFs continue to receive all RECs associated with their output, the ratepayer indifference standard under PURPA would not be met.

<u>POST-IRP EXPANSION PLAN PRICING</u>

Q. What is the second non-routine avoided cost input change proposed by the Company?

A. The Company's 2017.Q1 Filing proposed that avoided cost pricing beyond the end of the preferred portfolio be calculated by escalating the final year values at inflation.

Q. Which parties challenged this update?

A. UCE and sPower both challenged the Company's post-IRP resource expansion plan pricing proposal.

Q. What is the basis for the Company's proposal?

A. The 2017 IRP is based on a planning reserve margin of 13 percent, and identifies the least-cost, least-risk portfolio of resources necessary to achieve that planning reserve margin through 2036. The Proxy/PDDRR methodology assumes that QFs defer capacity-equivalent amounts of resources from the 2017 IRP preferred portfolio, such that the planning reserve margin of 13 percent is maintained. The 2017 IRP preferred portfolio does not identify capacity resources necessary to maintain a 13 percent planning reserve margin in 2037 or beyond. Load growth, expiring purchase contracts, and the planned retirement of the Huntington plant at the end of 2036 all contribute to a planning reserve margin in and beyond 2037 that is below the target level of 13 percent without additional resources.

Q. Does the Company's proposal impact avoided capacity costs?

A. No. Avoided capacity costs already reflect real levelized values that escalate at inflation.

Q. Does the Company's proposal impact avoided energy costs?

A. Yes. While the load and resource balance in the IRP is based on meeting peak requirements, the preferred portfolio identifies resources which support the least-cost, least-risk optimization of system costs throughout the year. In the absence of IRP expansion resources, the GRID model is increasingly forced to rely upon market transactions and the highest marginal cost resources on the system in all hours of the year. In reality, the addition of resources sufficient to meet the planning reserve margin would reduce the Company's avoided energy costs, particularly if the additions include wind or solar resources with zero marginal costs. As a result, the GRID model cannot produce accurate avoided energy costs if capacity sufficient to meet the load and planning reserve margin is not identified and included in the model.

Q. Does the Company's proposal impact any Utah QFs that are currently negotiating contracts?

A. Not at this time. As indicated above, the 2017 IRP preferred portfolio extends through 2036. The Qualifying Facility Procedures contained in Schedule 38 include specific deadlines for QFs seeking a power purchase agreement ("PPA"). To retain their queue position, a QF developer must request a proposed PPA and submit required information within sixty days of receiving indicative pricing, which is to be provided within 30 days of confirmation of a complete pricing request. After providing confirmation of completeness within seven days, the Company must provide a proposed PPA within 30 days of the notice of completeness. A QF developer also must execute a PPA within five months of receiving the proposed PPA. In addition, indicative prices must be updated unless a PPA is executed within six months of indicative pricing being provided. The negotiation process thus involves up to six to eight months from the receipt of initial indicative pricing to contract execution, or approximately seven to nine months from an initial indicative pricing request to contract execution. In accordance with the Qualifying Facility Procedures, the scheduled commercial operation date for a QF must not be greater than 30 months after the execution date of the PPA. Finally, in accordance with the Commission order in Docket No. 15-035-53, QF contracts are limited to a 15-year term.

As a result of the aforementioned procedures, a QF requesting prices today could potentially execute a PPA based on those prices in March 2018, with a scheduled COD in September 2020, and a termination date in September 2035. This would still be within term of the 2017 IRP preferred portfolio.

The Company's mid-cycle IRP Updates have traditionally used the same study term as the most recent IRP. As a result, the preferred portfolio will not extend beyond 2036 until the expected March 31, 2019 filing of the Company's 2019 IRP. A QF receiving indicative prices in March 2019 could potentially execute a PPA based on those prices in October 2019, with a scheduled COD in April 2022, and a termination date in April 2037. This is beyond the expected term of the 2017 IRP Update preferred portfolio, which would be in effect at that time.

Q. Could a QF's contract term extend further beyond the end of the IRP preferred portfolio study period than described above?

A. Yes. It is possible that a dispute could result in a delay of a QF's scheduled COD. It is appropriate to establish a just and reasonable avoided cost methodology for such circumstances now, rather than as part of an individual dispute.

Q. Is the determination of avoided energy value beyond the end of the IRP preferred portfolio study period relevant in any other contexts?

A. The GRID model is a powerful tool for evaluating the Company's future resource dispatch and costs and has been employed in the evaluation of major plant additions as well as the allocation of costs between the Company's jurisdictions, both of which could extend beyond the 15-year term applicable to QFs. The GRID model's ability to accurately forecast conditions is limited by the available model inputs, of which the IRP preferred portfolio is essential, as it provides a least-cost, least-risk portfolio of resources and maintains the targeted planning reserve margin.

Q. What do you conclude with regard to post-IRP resource expansion plan pricing?

A. The 2017 IRP preferred portfolio only identifies a least-cost, least-risk portfolio of resources sufficient to maintain the targeted planning reserve margin through 2036. Avoided capacity costs are already escalated at inflation, and escalating 2036 avoided energy costs at inflation will produce more accurate avoided costs than the use 2037 GRID model results that are not based on an optimized portfolio of resources necessary to maintain a target planning reserve margin.

<u>SCHEDULE 37 METHODOLOGY</u>

Q. Please describe the current Commission-approved method for calculating avoided costs for small QFs qualifying for published rates 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 10-MW baseload QF resource at zero cost and displacement of FOTs.[10] The difference in net power costs ("NPC") between the two GRID runs divided by the energy produced by the QF resource determines the avoided energy cost. Avoided costs during a deficiency period begin coincident with the next deferrable major thermal resource identified in the Company's most recent IRP or IRP Update and are equal to the fixed and variable costs

[10] 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.

of a proxy resource, currently a combined cycle combustion turbine ("CCCT") plant.

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 Proxy/PDDRR method described above. The methods are similar in that both use the GRID model to determine avoided costs during the sufficiency period, with displacement of FOTs, and both include capacity costs in the deficiency period. The Proxy/PDDRR method differs in that it allows for deferral of cost-effective "like" renewable resources identified in the Company's IRP preferred portfolio. The Proxy/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. Furthermore, the Proxy/PDDRR method accounts for the specific characteristics of a proposed QF and a proxy resource, including 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. Finally, the Schedule 38 pricing methodology accounts for the resource characteristics and preferred portfolio displacement from the queue of potential QFs that are seeking to sell QF power to the Company.

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

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

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

A. Wind, solar, and geothermal resources are part of the Company's 2017 IRP preferred portfolio, representing the company's least-cost, least-risk plan to serve system load. This is the first time renewable resources planned to meet system load have been part of an IRP preferred portfolio since the Commission approved modifications to the Proxy/PDDRR methodology and made renewable resources eligible for deferral by QFs.

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

A. Under the Proxy/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. 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, each megawatt of east-side tracking solar resources is estimated to provide approximately 92 percent of the capacity provided by each megawatt of west-side tracking solar resources.[11] As a result, a 10 MW Utah tracking solar QF could defer 10 MW of an east-side tracking solar resource from the IRP preferred portfolio or 9.2 MW of a west-side tracking solar resource. The same capacity contribution study indicates that an east-side wind resource provides approximately 134 percent of the capacity provided by each megawatt of west-side wind.[12] Consequently, a 10 MW Utah wind QF could defer 10 MW of an east-side wind resource from the IRP preferred portfolio or 13.4 MW of a west-side wind resource. If the IRP renewable resources of a given type, pricing would revert to partially displacing the next thermal resource adjusted for the capacity contribution of the QF.

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

A. The 1,100 MW of new PTC-eligible Wyoming wind resources added by the end of 2020 in the 2017 IRP preferred portfolio will use the transmission capability made available by constructing Aeolus-to-Bridger/Anticline line, a new 144-mile, 500 kV transmission project that will run from the Aeolus substation near Medicine Bow, Wyoming, to a new substation near the Jim Bridger plant. The wind and transmission additions provide all-in economic benefits to the Company customers in all

[11] East Tracking Solar: 59.7%. West Tracking Solar: 64.8%. 59.7% / 64.8% = 92%.
[12] East Wind: 15.8%. West Wind: 11.8%. 15.8% / 11.8% = 134%.

jurisdictions when considered as a package.

As previously described, partial displacement is reasonable when capacity additions can be delayed or scaled down as a result of a QF resource addition. The addition of a Utah wind QF project would not defer the new wind and transmission planned to come online by the end of 2020 in the Company's 2017 IRP preferred portfolio. Given the net benefits these projects provide to the Company's retail customers, it will pursue these projects even if new QF projects were added to the system in Utah. As a result, Utah wind QFs can displace the 2031 and 2036 wind resource additions in the 2017 IRP preferred portfolio. After accounting for the QF queue, and the queue position established for Schedule 37 pricing in Docket No. 17-035-T07, the updated Schedule 37 pricing reflects deferral of 2031 wind resources from the 2017 IRP preferred portfolio.

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

A. Since the 2017 IRP was prepared, the Company executed power purchase agreements with four solar QFs totaling 135 MW of nameplate capacity and has terminated one solar QF PPA with 5 MW of nameplate capacity. These solar resources displace all of the 2028 and 2029 solar resources and a portion of the 2031 solar resources in the 2017 IRP preferred portfolio. After accounting for the potential QF queue, and the queue position established for Schedule 37 pricing in Docket No. 17-035-T07, the updated Schedule 37 pricing reflects deferral of 2033 solar resources from the 2017 IRP preferred portfolio.

Q. Are there additional considerations for determining resource deferral under the Proxy/PDDRR methodology?

A. Yes. The Proxy/PDDRR method gives priority to QFs in the order of requests for avoided cost prices. As the earliest resources in the IRP preferred portfolio are displaced, successive requests receive capacity starting in later years. In addition, the generation from all QFs in the queue is included in the GRID model. The GRID model optimizes the dispatch of the system to minimize costs, so a QF's output displaces the resources with the highest variable cost in each interval and avoided energy costs decline as each successive QF is added. As a result, avoided cost prices are highest for the first QF in the queue and are lower for QFs later in the queue.

Q. Is it reasonable to incorporate a QF queue under Schedule 37?

A. Yes. As described above, Schedule 37 prices calculated without accounting for the pricing queue will reflect the earliest resource deferral and highest avoided costs. As QFs in Utah and other states sign long-term PPAs, the earliest resources would be deferred and Schedule 37 prices calculated without the QF queue would be overstated. The Company therefore proposes that the Proxy/PDDRR calculation for Schedule 37 rates incorporate the potential QF queue.

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

A. As shown in Table 2, the Company's May 30, 2017 filing in Docket No. 17-035-T07 showed Schedule 37 avoided cost prices for all resource types under the Proxy/PDDRR methodology that were lower than prices under the current Schedule 37 methodology, which are now in effect. The Proxy/PDDRR prices from May assumed that the

Schedule 37 resources were placed at the end of the potential QF queue at the time. Also shown in Table 2 are updated Proxy/PDDRR prices reflecting the latest signed QFs and projects that have dropped out, assuming the Schedule 37 resources retained the queue position from the May filing.

Updating the potential QF queue increases avoided cost prices for all resource types relative to the Proxy/PDDRR prices proposed in May. The proposed prices for wind resources are also higher than the currently effective prices, while the prices for base load and solar resources are lower than the current prices. Under the proposed method, avoided cost prices for wind and solar resources are higher once the deficiency period is reached, while prices for base load resources are comparable to the currently effective prices. The proposed avoided cost prices are lower during the deficiency period due to the aggregate effect of existing and potential resources on the Company's system, as well as resource specific delivery patterns. The impact is largest for solar because the daily and seasonal output of solar QFs is highly correlated with the Company's existing and potential solar resources.

Table 2: Summary of Schedule 37 Avoided Cost Prices

15 Year (2018 to 2032) Nominal Levelized Prices ($/MWh)					
Methodology Version	**GRID/Proxy Current Rates**	**Proxy/PDDRR May Queue**	**Proxy/PDDRR August Queue**	**August Queue vs Current**	**August Queue vs May Queue**
Base Load	$29.49	$23.82	$27.25	($2.24)	$3.44
Wind	$24.85	$23.86	$25.92	$1.07	$2.05
Fixed-Tilt Solar	$28.21	$19.78	$22.65	($5.56)	$2.87
Tracking Solar	$29.22	$19.60	$22.85	($6.37)	$3.25

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

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

Q. Does this conclude your direct testimony?

A. Yes.

Appendix 1

Table 1
2017 IRP Preferred Portfolio
Excerpt from 2017 IRP Table 8.17

		Capacity (MW)																				Resource Totals 1/	
	Resource	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Expansion Resources**																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	774	-	774
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	85	-	-	-	-	774	1,100	1,959
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	167	210	41	291	13	-	800
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	300	291	300	300	300	300	300	300	3	137
West	**Expansion Resources**																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	11	97	-	38	70	16	8	-	-	-	240
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	41	-	10	167	76	137	400	400	400	400	400	400	400	400	364	30	200
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	299	375	344	375	375	375	375	375	375	375	375	375	375	375	375	375	285	330
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	308	-	287	295	-	-	-	400	41	390	351	-	377	4	291	208	197
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	312	51	375	-	-	337	-	375	375	92	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(257)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,223	114	118	118	112	111	109	306	563	536	303	323	980	117	356	861		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	1,336	1,987	2,126	2,081	2,065	2,026	2,012	2,052	2,054	2,305		
	Total Annual Additions	935	981	1,282	1,236	2,341	1,337	1,268	1,289	1,501	1,440	1,445	2,293	2,688	2,618	2,368	2,349	2,992	2,169	2,411	3,166		

The 2017 IRP was prepared using a 13% planning reserve margin. See 2017 IRP, page 10.

QF Queue						
No.	**QF**	**Partial Displacement**	**Name plate**	**CF**	**Capacity Contribution**	**Start Date**
1	Boswell Springs I Wind	12.64	80.00	40.7%	15.8%	2018 12 31
2	Boswell Springs II Wind	12.64	80.00	40.7%	15.8%	2018 12 31
3	Boswell Springs III Wind	12.64	80.00	40.7%	15.8%	2018 12 31
4	Boswell Springs IV Wind	12.64	80.00	40.7%	15.8%	2018 12 31
5	Glen Canyon A Solar QF	44.18	74.00	32.2%	59.7%	2019 09 29
6	Glen Canyon B Solar QF	12.54	21.00	34.9%	59.7%	2019 11 01
7	Sage I Solar QF	11.94	20.00	28.2%	59.7%	2019 10 01
8	Sage II Solar QF	11.94	20.00	28.2%	59.7%	2019 10 01
9	BYU-ID QF	4.20	5.60	79.0%	74.9%	2017 09 29
10	Beatty Solar (Terminated)	-3.24	-5.00		64.8%	2016 12 01
Total Signed MW		50.56	320.00			

1	QF - 245 - WY - Wind	12.64	80.00	44.9%	15.8%	2018 11 01
2	QF - 246 - WY - Wind	12.64	80.00	42.0%	15.8%	2018 11 01
3	QF - 247 - WY - Wind	12.64	80.00	37.4%	15.8%	2018 11 01
4	QF - 249 - OR - Solar	25.92	40.00	29.1%	64.8%	2017 12 31
5	QF - 279 - OR - Solar	25.92	40.00	31.0%	64.8%	2018 06 30
6	QF - 280 - OR - Solar	25.92	40.00	27.9%	64.8%	2018 12 01
7	QF - 281 - OR - Solar	25.92	40.00	24.5%	64.8%	2018 12 01
8	QF - 302 - WY - Solar	9.55	16.00	29.3%	59.7%	2019 10 01
9	QF - 328 - OR - Solar	29.81	46.00	28.7%	64.8%	2018 12 01
10	QF - 336 - UT - Solar	34.61	58.00	33.9%	59.7%	2018 07 01
11	QF - 351 - OR - Solar	35.64	55.00	28.0%	64.8%	2019 01 01
12	QF - 254 - OR - Solar	35.64	55.00	24.6%	64.8%	2020 12 31
13	QF - 372 - WY - Solar	23.87	40.00	27.4%	59.7%	2019 06 30
14	QF - 380 - OR - Solar	32.40	50.00	25.8%	64.8%	2019 01 01
15	QF - 381 - OR - Solar	51.84	80.00	29.3%	64.8%	2021 01 01
16	QF - 397 - OR - Solar	12.96	20.00	29.3%	64.8%	2021 01 01
17	QF - 382 - UT - Solar	47.74	80.00	31.5%	59.7%	2020 06 01
18	QF - 383 - OR - Solar	51.84	80.00	28.0%	64.8%	2019 12 01
19	QF - 384 - OR - Solar	51.84	80.00	28.0%	64.8%	2019 12 01
20	QF - 385 - OR - Solar	51.84	80.00	28.0%	64.8%	2019 12 01
21	QF - 386 - UT - Solar	47.74	80.00	30.8%	59.7%	2020 06 30
22	QF - 387 - UT - Solar	47.74	80.00	29.6%	59.7%	2019 12 01
Total Potential MW		706.66	1300.00			

Total Partial Displacement		**757.22**	**1620.00**

Table 3
Comparison between Proposed and Current Avoided Costs

	BASE LOAD			**WIND**			**SOLAR FIXED**			**SOLAR TRACKING**		
Year	Proposed Avoided Costs	Current Avoided Costs	Total Difference	Proposed Avoided Costs	Current Avoided Costs	Total Difference	Proposed Avoided Costs	Current Avoided Costs	Total Difference	Proposed Avoided Costs	Current Avoided Costs	Total Difference
	($/MWH)	($/MWH)	($/MWH)	($/MWH)	($/MWH)	($/MWH)	($/MWH)	($/MWH)	($/MWH)	($/MWH)	($/MWH)	($/MWH)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
			(a) - (b)			(d) - (e)			(g) - (h)			(j) - (k)
2018	$20.06	$20.39	($0.33)	$18.16	$18.99	($0.84)	$19.59	$20.73	($1.14)	$19.35	$20.51	($1.17)
2019	$18.89	$19.59	($0.70)	$16.69	$18.08	($1.39)	$17.74	$20.38	($2.64)	$17.70	$20.30	($2.61)
2020	$17.78	$18.49	($0.71)	$16.47	$16.92	($0.45)	$16.74	$19.41	($2.67)	$16.65	$19.38	($2.73)
2021	$17.00	$18.79	($1.79)	$16.67	$17.27	($0.61)	$15.63	$19.49	($3.87)	$15.49	$19.44	($3.94)
2022	$19.19	$20.43	($1.24)	$17.70	$18.99	($1.29)	$16.40	$21.05	($4.65)	$16.37	$21.03	($4.66)
2023	$20.61	$21.86	($1.26)	$19.20	$20.56	($1.36)	$17.90	$22.37	($4.46)	$18.00	$22.42	($4.43)
2024	$23.35	$24.97	($1.62)	$22.58	$23.71	($1.14)	$17.08	$25.36	($8.28)	$17.75	$25.41	($7.66)
2025	$24.92	$27.43	($2.51)	$22.93	$26.10	($3.17)	$21.10	$28.06	($6.96)	$21.45	$28.20	($6.74)
2026	$25.54	$30.44	($4.90)	$24.92	$28.86	($3.95)	$22.24	$30.86	($8.62)	$22.50	$30.68	($8.18)
2027	$26.34	$28.29	($1.95)	$25.17	$26.96	($1.80)	$21.28	$28.79	($7.51)	$21.85	$28.91	($7.06)
2028	$32.43	$34.40	($1.97)	$30.59	$32.96	($2.37)	$29.82	$35.08	($5.26)	$30.41	$35.21	($4.80)
2029	$37.29	$54.20	($16.91)	$35.36	$35.71	($0.35)	$34.63	$44.79	($10.16)	$35.08	$50.24	($15.15)
2030	$56.38	$57.16	($0.78)	$39.43	$38.24	$1.19	$38.61	$47.54	($8.94)	$39.00	$53.11	($14.12)
2031	$58.40	$59.28	($0.87)	$67.03	$39.88	$27.15	$39.62	$49.42	($9.80)	$40.15	$55.12	($14.97)
2032	$60.73	$61.65	($0.92)	$68.36	$41.79	$26.58	$42.67	$51.55	($8.88)	$43.39	$57.39	($14.00)
2033	$63.87	$64.73	($0.86)	$72.59	$44.40	$28.20	$71.77	$54.40	$17.37	$82.14	$60.38	$21.77
2034	$66.24	$67.07	($0.83)	$76.11	$46.25	$29.86	$74.51	$56.49	$18.02	$84.66	$62.62	$22.04
2035	$68.72	$69.49	($0.77)	$76.67	$48.17	$28.50	$76.88	$58.65	$18.24	$87.05	$64.93	$22.12
2036	$72.33	$73.47	($1.13)	$76.96	$51.62	$25.34	$79.74	$62.36	$17.38	$89.33	$68.78	$20.55

(x) Extrapolated
15 Year (2018 to 2032) Levelized Prices (Nominal) @ 6.570% Discount Rate

$/MWH	$27.25	$29.49	($2.24)	$25.92	$24.85	$1.07	$22.65	$28.21	($5.56)	$22.85	$29.22	($6.37)

	Generation Profile_Baseload	Generation Profile_Wind*	Generation Profile_Solar Fixed	Generation Profile_Solar Tracking
on-peak Summer	19%	13%	31%	33%
on-peak Winter	37%	24%	52%	46%
off-peak Summer	15%	25%	7%	10%
off-peak Winter	29%	39%	10%	11%

Table 4
Natural Gas Price - Delivered to Plant
$/MMBtu

Year	Pacific NW	IRP - Wyo NE
	(a)	(b)
2018	$2.72	$2.70
2019	$2.50	$2.48
2020	$2.50	$2.48
2021	$2.52	$2.53
2022	$2.53	$2.55
2023	$2.91	$2.99
2024	$3.50	$3.61
2025	$3.78	$3.81
2026	$3.77	$3.81
2027	$3.92	$3.95
2028	$4.15	$4.15
2029	$4.51	$4.47
2030	$4.88	$4.81
2031	$5.11	$5.04
2032	$5.38	$5.28
2033	$5.76	$5.62
2034	$6.02	$5.90
2035	$6.29	$6.23
2036	$6.80	$6.70
2037	$7.05	$6.90

Source

Official Forward Price Curve dated March 31 2017

Table 5
Electricity Market Prices
$/MWH

Year	Market Price $/MWH			
	HLH		LLH	
	Mid-Columbia	Palo Verde	Mid-Columbia	Palo Verde
	(a)	(b)	(c)	(d)
2018	$24.29	$26.33	$18.49	$21.86
2019	$25.11	$27.03	$19.18	$21.46
2020	$27.21	$28.64	$20.99	$22.01
2021	$28.78	$30.10	$23.04	$23.79
2022	$30.74	$31.49	$24.58	$25.76
2023	$33.50	$33.87	$27.47	$28.81
2024	$37.10	$36.76	$30.79	$32.08
2025	$39.49	$39.08	$33.18	$33.95
2026	$40.27	$39.84	$33.95	$34.69
2027	$41.36	$40.83	$35.10	$35.89
2028	$43.71	$42.66	$37.19	$37.74
2029	$45.85	$44.88	$39.29	$40.02
2030	$48.25	$47.33	$41.83	$42.63
2031	$50.32	$49.33	$43.73	$44.41
2032	$52.51	$51.66	$45.82	$46.63
2033	$55.22	$54.43	$48.63	$49.46
2034	$57.39	$56.37	$50.74	$51.45
2035	$59.90	$58.90	$52.71	$53.67
2036	$63.38	$62.67	$56.24	$57.42
2037	$66.12	$65.02	$58.81	$59.66

Source

Official Forward Price Curve dated March 31 2017

Table 6
Integration Costs
$/MWH

Year	System Balancing Integration Costs $/MWh	Wind Integration (Incremental) $/MWh	Tracking Solar Integration (Incremental) $/MWh
2016	$0.145	$0.429	$0.458
2017	$0.15	$0.44	$0.47
2018	$0.15	$0.45	$0.48
2019	$0.15	$0.46	$0.49
2020	$0.16	$0.47	$0.50
2021	$0.16	$0.48	$0.51
2022	$0.16	$0.49	$0.52
2023	$0.17	$0.50	$0.53
2024	$0.17	$0.51	$0.55
2025	$0.18	$0.52	$0.56
2026	$0.18	$0.53	$0.57
2027	$0.18	$0.55	$0.58
2028	$0.19	$0.56	$0.60
2029	$0.19	$0.57	$0.61
2030	$0.20	$0.59	$0.63
2031	$0.20	$0.60	$0.64
2032	$0.21	$0.61	$0.66
2033	$0.21	$0.63	$0.67
2034	$0.22	$0.65	$0.69
2035	$0.22	$0.66	$0.71
2036	$0.23	$0.68	$0.72
2037	$0.23	$0.69	$0.74
2038	$0.24	$0.71	$0.76
2039	$0.25	$0.73	$0.78
2040	$0.25	$0.75	$0.80
2041	$0.26	$0.76	$0.82
2042	$0.26	$0.78	$0.84

CERTIFICATE OF SERVICE

Docket No. 17-035-T07 and 17-035-37

I hereby certify that on August 17, 2017, a true and correct copy of the foregoing was served by electronic mail to the following:

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