ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple
Salt Lake City, Utah 84116

April 9, 2020

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attn: Gary Widerburg
Commission Administrator

Re: **Advice Filing 20-05**
Docket No. 20-035-T04 - Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities
Docket No. 19-035-18 – 2019.Q3 Avoided Cost Input Changes Quarterly Compliance Filing

In accordance with the Amended Scheduling Order, Notice of Technical Conference and Notice of Hearing issued by the Public Service Commission of Utah ("Commission") on March 26, 2020 in the above referenced docket, Rocky Mountain Power (the "Company") hereby submits its Supplemental Filing in support of the avoided cost changes presented in its filing on January 10, 2020. The Supplemental Filing includes the direct testimony of Company witness Mr. Daniel J. MacNeil along with supporting workpapers.

Also included in this filing is the Company's annual update to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities ("Schedule 37") pursuant to Commission Rules R746-405 and the Commission's February 12, 2009 order in Docket No. 08-035-78 on Net Metering Service ("Order"). In accordance with the Order, the Company calculates and files Schedule 37 avoided costs annually in order to establish the value or credit for net excess generation of large commercial customers under Schedule 135 Net Metering Service. Per the Commission's order issued on November 28, 2012 in Docket No. 12-035-T10, the annual filings are made within 30 days of filing the Company's Integrated Resource Plan ("IRP") or IRP Update, or by April 30 of each year, whichever occurs first. Per its notice filed in Docket No. 19-035-02 on November 13, 2019, the Company does not plan to file a 2019 IRP Update.

Proposed tariff sheets, two appendices, and accompanying workpapers are submitted herewith for electronic filing in the above referenced matter. The enclosed proposed tariff sheets are associated with Tariff P.S.C.U No. 50 of PacifiCorp, d.b.a. Rocky Mountain Power, applicable to electric service in the State of Utah. Pursuant to the requirement of Commission Rule R746-405D, PacifiCorp states that the proposed tariff sheets do not constitute a violation of state law or Commission rule. PacifiCorp respectfully requests an effective date of July 31, 2020.

Eleventh Revision of Sheet No. 37.4	Schedule 37	Avoided Cost Purchases From Qualifying Facilities
Tenth Revision of Sheet No. 37.5	Schedule 37	Avoided Cost Purchases From Qualifying Facilities
Tenth Revision of Sheet No. 37.6	Schedule 37	Avoided Cost Purchases From Qualifying Facilities
Tenth Revision of Sheet No. 37.7	Schedule 37	Avoided Cost Purchases From Qualifying Facilities

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

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Very truly yours,

Joelle Steward
Vice President, Regulation

cc: Service List (Docket No. 19-035-18)

Rocky Mountain Power
Docket No. 19-035-18
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Daniel J. MacNeil

April 2020

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 updated published pricing under Schedule 37, Avoided Cost Purchases from Qualifying Facilities. My testimony also provides support for a non-routine change to the Proxy/Partial Displacement Differential Revenue Requirement ("Proxy/PDDRR") methodology used to develop pricing for wind resources under both Schedule 37 and Schedule 38, as identified in the Company's January 10, 2020 Avoided Cost Input Changes Quarterly Compliance Filing[1] (2019.Q3 Filing).

Q. Please describe the Company's 2019.Q3 Filing and challenges to the filing.

A. The 2019.Q3 Filing identified four routine updates and one non-routine update. Utah Clean Energy ("UCE") challenged two main aspects of these updates, specifically:

- Routine updates associated with the 2019 Integrated Resource Plan ("IRP"), particularly as they relate to the Proxy/Partial Displacement Differential Revenue Requirement ("Proxy/PDDRR") methodology, including the assumed deferral of solar with storage resources in the 2019 IRP preferred portfolio by Utah tracking solar qualifying facilities.
- The non-routine update related to the assumed resource deferral associated with Utah wind qualifying facilities ("QFs").

Q. How is your testimony organized?

A. My testimony first describes the currently approved and effective Proxy/PDDRR methodology for determining avoided costs under Schedules 37 and 38, and identifies the proposed Schedule 37 rates under the current methodology. In response to UCE's challenges to the Company's 2019 IRP updates, I describe in detail how the Proxy/PDDRR methodology is implemented based on the 2019 IRP preferred portfolio. My testimony next provides justification for the non-routine methodology update related to the assumed resource deferral for Utah wind QFs.

[1] 2019 Avoided Cost Input Changes – Quarterly Compliance Filing. Docket No. 19-035-18. Available at: https://psc.utah.gov/2019/04/30/docket-no-19-035-18/.

PROXY/PDDRR METHODOLOGY

Q. Please describe the methodology the Company currently uses to determine avoided costs under Schedules 37 and 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 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]

[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).

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 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. Most recently in Docket No. 17-035-37, the Company proposed modifications to the Proxy/PDDRR methodology applicable to avoided cost price projections for renewable resources. The following modifications proposed by the Company were adopted by the Commission in its January 23, 2018 order:

- Prioritizing like-for-like deferral of renewable resources from the IRP preferred portfolio, followed by deferral of thermal resources if no "like" renewable resources are present during a QF's proposed contract term.
- Assigning renewable energy credit ("REC") ownership to the Company during the

portion of the contract term that QF pricing is based on the deferral of renewable resources.

- Clarifying that pricing that extends beyond the conclusion of the IRP expansion plan would be based on the final year values, escalated at inflation.

Q. Did the Commission adopt any other proposals along with the aforementioned modifications to the Proxy/PDDRR methodology?

A. Yes. In its January 23, 2018 order, the Commission adopted the Company's proposal to use the Proxy/PDDRR methodology for the purpose of setting published avoided cost rates in Schedule 37. The one departure from the non-standard pricing methodology is that only signed contracts are assumed to be in place for the purpose of calculating deferrable resources and avoided energy costs, whereas non-standard pricing includes the effects of prior-queued QFs that have requested pricing and have ongoing negotiations. The first section of my testimony presents details on the Schedule 37 avoided costs consistent with the current Proxy/PDDRR methodology.

Q. Did the Commission reject any of the Company's proposals in the most recent proceeding?

A. Yes. In Docket No. 17-035-37 the Company requested that the like-for-like deferral assumption be waived with regard to the 1,100 megawatt ("MW") of new Wyoming wind resources in the 2017 IRP preferred portfolio that were tied to the Aeolus-to-Bridger/Anticline transmission line. The Commission rejected this proposal and required the Company to include both the wind resources and associated transmission as deferrable resources for wind QFs. The second section of my testimony addresses the accuracy of the current Proxy/PDDRR methodology as it relates to wind QFs.

While the 1,100 MW of new Wyoming wind resources have been replaced by signed contracts and are no longer deferrable, the 2019 IRP preferred portfolio includes 1,920 MW of new Wyoming wind resources associated with the Gateway South transmission upgrade with much the same circumstances. My testimony demonstrates that the assumed deferral of these wind and transmission resources does not result in avoided costs for Utah wind QFs that are consistent with the customer indifference principle.

THE 2019 IRP

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 2019 IRP preferred portfolio includes wind, solar, thermal and energy storage resources. Some of the wind resources and all of the solar resources are also combined with energy storage as part of a single facility.

Q. What resources are included in the 2019 IRP preferred portfolio over the next ten years?

A. The 2019 IRP preferred portfolio includes a wide variety of resource additions through the IRP study term through 2038. For avoided cost purposes, the most relevant resources are the first ones to occur of each type:

Thermal:

- 2026: Naughton simple cycle combustion turbine (“SCCT”) (185 MW)
- 2030: Naughton SCCT (2 x 185 MW)

Wind:

- 2023: Utah South wind (69 MW) – designated renewable resource for customer preference requirements
- 2024: Aeolus wind (1,920 MW)
- 2029: Yakima wind combined with energy storage (10 MW)
- 2030: Goshen wind (1,040 MW)

Solar:

- 2021 to 2024: Utah South solar combined with energy storage (558 MW) – designated renewable resources for customer preference requirements
- 2024: Utah North solar combined with energy storage (231 MW)
- 2024: Utah South solar combined with energy storage (342 MW)
- 2024: Jim Bridger solar combined with energy storage (354 MW)
- 2024: Southern Oregon solar combined with energy storage (500 MW)
- 2024: Yakima solar combined with energy storage (395 MW)
- 2029: Jim Bridger solar combined with energy storage (359 MW)

- 2030: Utah South solar combined with energy storage (500 MW)

Energy Storage:

- 2028-2029: Oregon lithium-ion four-hour duration batteries (435 MW)
- 2028-2029: Washington lithium-ion four-hour duration batteries (180 MW)

Q. What are customer preference resources?

A. Certain Utah customers have plans or targets to be served with 100 percent net renewable energy for all or a portion of their load, which may be met through renewable energy purchases or RECs. While the preferred portfolio includes a large quantity of renewable resources over the study period to serve system load, additional renewables over the near term to enable customers to meet their specific renewable targets result in higher costs that would be paid by those customers. The 2019 IRP preferred portfolio includes renewable resources sufficient to meet these customer's requests. A sensitivity prepared as part of the 2019 IRP indicated that system costs could be $81 million lower over the course of the IRP study period in the absence of these requirements.[4] As a result, these resources are not considered cost-effective and therefore are not available for deferral under the approved Proxy/PDDRR methodology, consistent with the Commission's August 16, 2013 order in Docket No. 12-035-100.

Q. Please describe how wind and solar resources can be combined with energy storage.

A. Lithium-ion battery resources typically have a relatively small footprint and relatively modular design, such that they can be incorporated with other types of assets with relative ease. Co-locating energy storage resources with other resources can allow for

[44] 2019 IRP. Volume I. Table 8.30.

operations and maintenance savings and avoid interconnection costs to the extent the facility is operated such that the combined output never exceeds the nameplate capacity of the other resource. In addition, energy storage paired with a solar resource can be eligible for investment tax credits equal to those that apply to solar facilities, so long as it is charged using the onsite solar resource during the first five years of operation. With an investment tax credit of up to 30% for solar facilities that come online by the end of 2023, energy storage resources that are combined with solar (and thus receive an equal investment tax credit rate) can be acquired at significantly lower cost than either as a stand-alone facility or as part of a non-solar facility. During the 2019 IRP process, the Company found that the benefits of combining solar and storage were so great that all stand-alone solar options were removed. Additionally, because battery storage does not qualify for tax credits as part of a wind resource receiving production tax credits, the value of combining wind and storage is not as high as combined solar and storage.

PROXY/PDDRR DEFERRABLE RESOURCES

Q. Did the incorporation of the 2019 IRP preferred portfolio require any enhancements to the resource deferral determination under the Proxy/PDDRR methodology?

A. Yes. Under Proxy/PDDRR methodology, a renewable resource defers the next resource in the preferred portfolio of the same type. Because the 2019 IRP preferred portfolio includes proxy solar and storage resources at five different locations in 2024 (as a proxy for year-end 2023 to capture the benefit of investment tax credits), the Company has assumed that resource deferrals in that year will be prioritized based on geographic proximity. As a result, solar QFs in southern Utah defer IRP solar resources in southern Utah first, solar QFs in northern Utah defer IRP solar resources in northern Utah first, and solar QFs in Wyoming defer IRP solar resources at Jim Bridger first. In the event all of the IRP resources of the QF's type in the QF's location are fully deferred, the next closest IRP resource of that type coming online in that year is deferred. This continues until all IRP resources of that type coming online in that year are deferred.

Q. Why is resource deferral based on geographic proximity reasonable?

A. The Company's 2019 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. While the GRID model does not enforce the planning reserve margin requirements by transmission area, preferentially deferring resources in the comparable locations can help maintain the balance of load and resources in the IRP preferred portfolio, which is the least-cost, least-risk outcome.

As resources are added to a particular area, that area will become a net exporter in an increasing number of intervals. Once transmission export limits are reached, incremental resource additions will have lower avoided energy values, as economic resources in that area with relatively low marginal costs will no longer be able to be transferred to higher value areas. By deferring IRP resources from the area where a QF is being added, the impact on net exports is reduced, and avoided energy values will be relatively higher.

The Company reiterates that geographic location is only used as a tiebreaker when multiple resources of a given type are added in the same year. Consistent with the approved methodology, the year of the next resource available for deferral is not impacted by the incorporation of location information.

Q. What resources from the 2019 IRP preferred portfolio are available for deferral by Utah QFs of different types?

A. For purposes of determining Schedule 37 avoided cost prices, the Proxy/PDDRR methodology is carried out based on the preferred portfolio without a potential QF queue and with adjustments for signed contracts only. After accounting for signed contracts only, the next deferrable resource for each resource type under the current Proxy/PDDRR methodology is as follows:

- Base Load: Naughton SCCT (185 MW in 2026)
- Wind: Aeolus wind (1,920 MW in 2024)
- Fixed Tilt Solar: Utah North solar combined with energy storage (231 MW in 2024)
- Tracking Solar: Utah North solar combined with energy storage (231 MW in 2024)

Q. What resource would be deferred under the Company's proposed non-routine update?

A. The Company's proposed non-routine update would impact the resource assumed to be deferred by wind resources only:

- Wind: Utah South customer preference wind (69 MW in 2023)

Additional details and support on the Company's proposed non-routine change are provided later in my testimony.

CAPACITY CONTRIBUTION

Q. Please explain how the amount of capacity deferred by a QF is determined.

A. To maintain the balance of loads and resources in the preferred portfolio, the capacity provided by a QF must be equivalent to the capacity being removed from the IRP preferred portfolio. The capacity contribution of a resource is represented as a percentage of that resource's nameplate or maximum capacity and is a measure of the ability of a resource to reliably meet demand. The determination of capacity contribution in the 2019 IRP is described in the Company's capacity contribution study.[5]

Q. Has the Company's capacity contribution study changed since the 2017 IRP?

A. Yes. The 2019 IRP capacity contribution study applies to an expanded range of resources, including stand-alone energy storage, energy efficiency, and renewable resources combined with energy storage. The capacity contribution analysis is also more granular than in previous IRPs, as it identifies distinct capacity contribution values for summer and winter peaks, evaluates duration-limited resources (including energy storage and interruptible load) on an iteration by iteration basis, and evaluates the decline in capacity contribution as wind and solar penetration increases. In addition, the 2019 IRP uses a capacity contribution specific to each proxy resource, whereas east and west values by resource type were used in the 2017 IRP. Also new in the 2019 IRP, PacifiCorp repeated the capacity contribution analysis at the end of the IRP process based on one of its final candidate portfolios. This creates capacity contribution results that are consistent with the wind, solar, and energy storage penetrations in the preferred portfolio, as the expected levels have changed dramatically over the course of the 2019 IRP portfolio development.

[5] 2019 IRP. Volume II. Appendix N: Capacity Contribution Study. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_M-R.pdf.

Q. Please explain how capacity contribution values were determined for the proxy resources available for deferral from the IRP preferred portfolio.

A. The capacity contribution of proxy resources in the preferred portfolio is estimated based on two inputs: a resource's hourly availability and the hourly loss of load probability ("LOLP") for the system. Resource availability is either the hourly generation profile for variable resources, or the maximum output after accounting for outages for dispatchable resources. Resource availability and system LOLP are related, particularly when variable resources reach high penetration levels, as loss of load events will be less likely when variable resource output is high.

In the 2019 IRP, wind and solar assets that were online in CY2017 have generation profiles based on CY2017 hourly actual output, with adjustments to account for differences in the total expected output. For proxy resources, and other resources that were not yet online, generation profiles are correlated with the actual hourly output of nearby existing resources from CY2017, again with adjustments to ensure the total output matches the expected amount. The hourly shaping methodology for potential resources is the same as that used for potential QFs and results in a unique hourly shape for each asset, based on its location and consistent with its expected output.[6]

The hourly system LOLP is calculated from the hours with energy shortfalls in 500 iterations of the 2030 test year with stochastic loads, hydro, and thermal outages. The hourly energy shortfall events identified in the 500 iterations are normalized so that the total LOLP across the 8760 hours in the test year adds up to 100%. Then the capacity contribution for each resource is calculated by multiplying its 8760 availability

[6] See 19-035-18. January 10, 2020 Filing. Appendix A. Pg. 3. fn 3.

by the system 8760 LOLP and summing the total.

Q. Are there any additional steps when applying the capacity contribution methodology from the 2019 IRP to potential QFs?

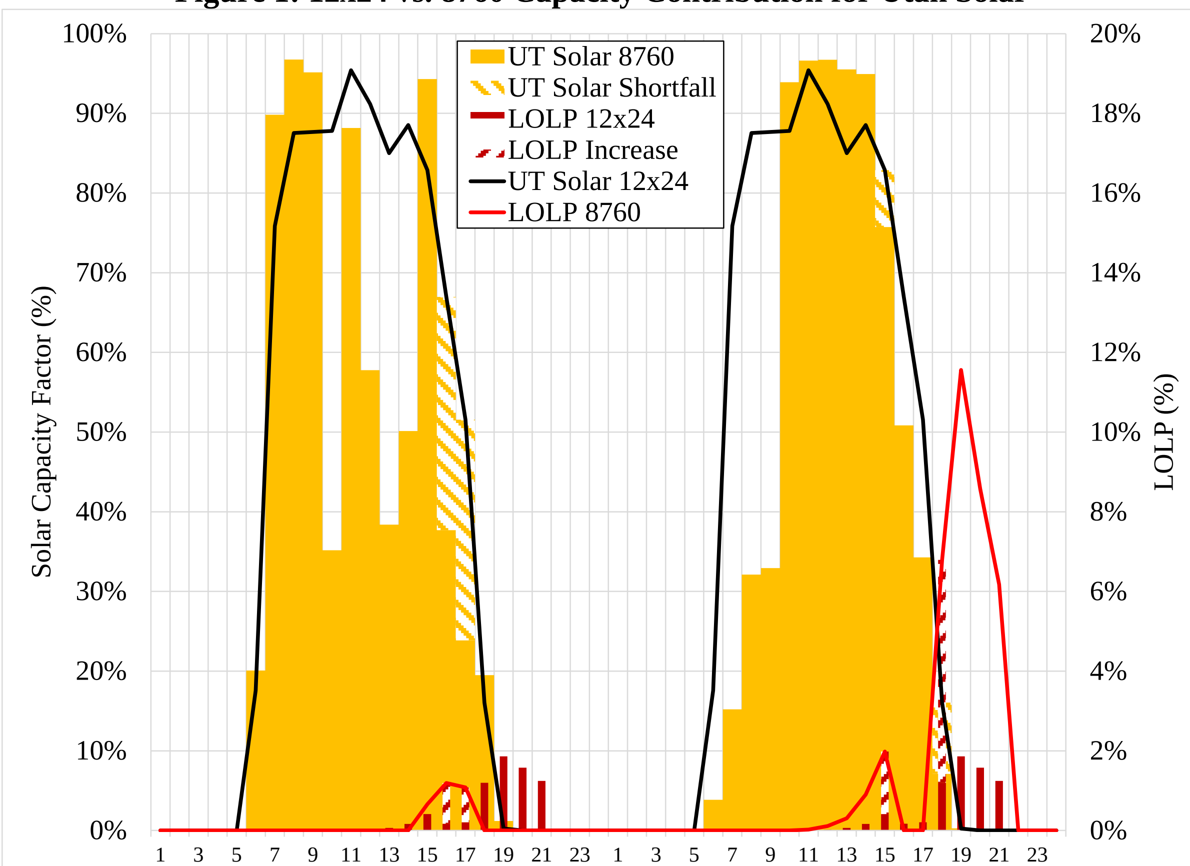
A. Yes. The 8760 LOLP is inherently tied to the preferred portfolio and the expected availability of the resources in that portfolio. The GRID model is currently populated with wind and solar generation profiles based on 2018 data, whereas the LOLP data from the 2019 IRP reflects wind and solar generation profiles based on 2017 data. Absent additional steps, a windy day in 2018 might line up with a calm day in 2017 that contributed to LOLP in the 2019 IRP analysis.

To compensate for this, the Company first averaged the 8760 LOLP from the 2019 IRP by hour and month to create a twelve-by-twenty-four (12x24) profile. Next, the Company calculated the capacity contribution of all of the 2019 IRP wind and solar generation profiles based on the 12x24 LOLP. Generally, the capacity contribution using the 12x24 LOLP is higher than the value based on the 8760 LOLP, as days with high resource output tend to have fewer loss of load events, especially if a location has significant renewable resources of a given type.

Q. Please provide an example of the difference between 12x24 and 8760 capacity contribution values.

A. Figure 1 illustrates the difference between these two values using the Utah solar generation profile from the 2019 IRP. Based on the 8760 LOLP and generation, the Utah solar profile has a summer capacity contribution of 9.9%. The orange diagonal lines show particular hours in which the Utah solar profile is below the monthly average. In those same hours, the red diagonal lines show hours in which the LOLP is above average. The combination of these effects is less generation during the hours of greatest need, and demonstrates how capacity contribution can be misrepresented when calculated on a 12x24 basis. As a result, the 12x24 summer capacity contribution for the Utah solar generation profile from the 2019 IRP is 11.5 percent, which is an increase over the more accurate 8760 calculation.

Figure 1: 12x24 vs. 8760 Capacity Contribution for Utah Solar



Q. How is the difference between 12x24 and 8760 capacity contribution values accounted for when evaluating potential QFs?

A. For a potential solar QF in Utah, the capacity contribution is calculated using the 12x24 LOLP, and the resulting value is reduced by 14 percent, consistent with the relationship between the 12x24 and 8760 values for Utah solar in the 2019 IRP. Analogous adjustments are applied to wind and solar in other geographic locations based on the proxy resource generation profiles in the 2019 IRP.

Q. Is the 2019 IRP capacity contribution methodology preferable to that in the 2017 IRP?

A. Yes. The 2019 IRP capacity contribution methodology produces values that are tied to the specific characteristics of each resource. As shown in Figure 1, the results assign a higher value to projects that produce greater system benefits by generating at a higher level into the evening, whether due to orientation, higher panel to inverter ratios, or the addition of energy storage.

Q. How does the 2019 IRP capacity contribution translate into partial displacement of resources under the Proxy/PDDRR methodology?

A. The translation of the capacity contributions of the generic Utah QFs of each type in Schedule 37 into the deferral of their respective proxy resources is shown in Table 1. Values consistent with the Company's proposed non-routine change to have Utah wind QFs defer Utah wind proxy resources is also shown.

Table 1: Proxy Resource Deferral Calculations

QF		Proxy		MW Deferred by 10MW QF	
Column:	a		b	c = a * 10 MW	d = c / b
Resource	**Cap. Contrib.**	**Resource**	**Cap. Contrib.**	**Contribution (MW)**	**Nameplate (MW)**
Baseload	100%	SCCT (NTN)	96.9%	10.00	10.3
Wind	17.9%	Wind (Aeolus)	12.7%	1.79	14.1
Wind	17.9%	Wind (Utah)	17.9%	1.79	10.0
Fixed Tilt Solar	4.3%	Solar & Storage (Utah North)	30.2%	0.43	1.4
Tracking Solar	9.9%	Solar & Storage (Utah North)	30.2%	0.99	3.3

Q. Is it reasonable for solar QFs to be considered the same type as a solar and storage proxy resources?

A. Yes. This is consistent with the Company's current implementation of the

Proxy/PDDRR methodology, as solar QFs that include battery storage have been assumed to defer stand-alone solar resources in the IRP preferred portfolio. Regardless of whether the solar resource in question is a QF or a proxy resource, 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 capacity contribution relative to a solar resource on its own. However, the capacity contribution associated with the underlying solar asset is still present. In the 2019 IRP, the solar resource corresponds to roughly one third of the total contribution, while the battery represents two-thirds. Capacity deferral based on a resource that is one-third solar is still preferable to deferral of resources without any solar characteristics.

Q. Does deferral of solar and storage resources by solar QFs result in energy impacts that are favorable to solar QFs?

A. Yes. When a solar and storage resource is partially displaced, it reduces the amount of resources available. The removal of the solar portion of the resource primarily impacts the hours in which a solar QF delivers. This is analogous to the impact of reducing the potential QF queue for Schedule 38 QF pricing. As more QFs are added, avoided costs decline, as the highest cost resources are backed down first. Reducing the quantity of proxy solar resources on the system likewise increases a solar QF's avoided energy costs relative to an avoided cost study in which no proxy solar resources are removed.

SCHEDULE 37 AVOIDED COST PRICING

Q. What are the Schedule 37 avoided costs under the Proxy/PDDRR methodology based on the deferral of resources from the 2019 IRP preferred portfolio?

A. Figure 2 presents the annual avoided cost prices for each resource type based on the resource deferrals previously described. Table 2 provides a summary of levelized avoided cost prices over the 15 year contract term available to Utah QFs, based on various start dates. Wind resource pricing is shown based on deferral of Wyoming wind and transmission resources in 2024 consistent with the approved Proxy/PDDRR methodology, as well as based on deferral of Utah wind and transmission resources in 2023, consistent with the Company's requested non-routine change.

Figure 2: Schedule 37 Avoided Cost Under Proxy/PDDRR Methodology

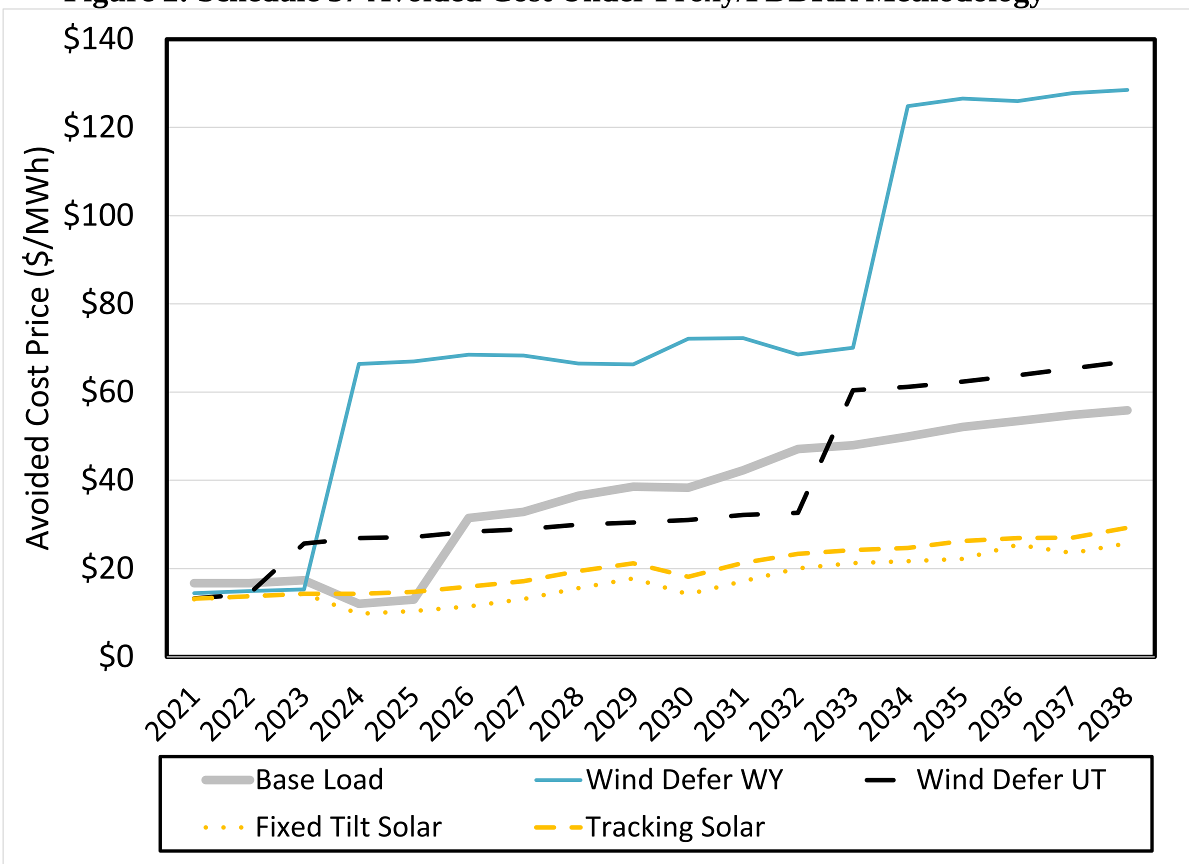


Table 2: Schedule 37 Avoided Cost by Resource and Start Date

15 Year Nominal Levelized Prices @ 6.92% Discount Rate ($/MWh)			
	Start Date		
Resource	**2021**	**2022**	**2023**
Base Load	$29.14	$31.47	$34.02
Wind Defer WY	$57.73	$65.19	$73.20
Wind Defer UT	$30.07	$33.26	$36.62
Fixed-Tilt Solar	$14.80	$15.41	$15.92
Tracking Solar	$17.61	$18.47	$19.33

Q. Why is it appropriate to consider avoided cost prices with start dates through 2023?

A. Utah QFs may select a commercial operation date (or a start date for a contract term for existing resources); however, that date may not be more than 30 months from contract execution. As a result, by July 1, 2020, QFs will be eligible to execute contracts that begin in 2023.

Q. What are the main drivers of the avoided cost prices for a base load QF shown in Figure 2?

A. Through 2025, the base load QF defers Front Office Transactions (FOTs), and has avoided cost prices that primarily reflect the value of redispatching resources in the Company's portfolio, with some reductions in market purchases and increases in market sales. Prices drop in 2024 as significant additions of wind and solar resources in the 2019 IRP preferred portfolio reduce marginal costs in many hours of the year. Starting in 2026, avoided costs increase as the base load QF begins deferring the proxy SCCT at Naughton, and is credited for avoided capital costs and fixed costs, net of the energy and operating reserve benefits the deferred portion of that plant provided within the GRID model.

Q. What are the main drivers of the avoided cost prices for wind resources deferring Wyoming wind shown in Figure 2?

A. Through 2023, the wind QF defers Front Office Transactions ("FOTs"), and has avoided cost prices that primarily reflect the value of redispatching existing PacifiCorp resources, with some reductions in market purchases and increases in market sales. Starting in 2024, avoided costs increase as the wind QF defers 14.1 MW of the proxy wind resource in eastern Wyoming, along with Gateway South transmission. The QF is credited for avoided capital costs and fixed costs, net of the benefits of the deferred portion of that wind resource and the Gateway South transmission path within the GRID model. The cost of the deferred wind resource is net of production tax credits during the first ten years, so avoided costs increase in 2034 when its production tax credits have expired. With a capacity factor of approximately 29 percent, the 10 MW Utah wind QF produces approximately 26,000 MWh annually, while the 14.1 MW of deferred Wyoming wind can produce up to 54,000 MWh annually, due to its larger size and higher capacity factor. The capital and fixed costs associated with the Gateway South transmission are a significant amount of the total price, amounting to approximately $23/megawatt-hour ("MWh") in 2024.

Q. What are the main drivers of the avoided cost prices for wind resources deferring Utah wind shown in Figure 2?

A. Through 2022, the wind QF defers FOTs, and has avoided cost prices that primarily reflect the value of redispatching existing PacifiCorp resources, with some reductions in market purchases and increases in market sales. Starting in 2023, avoided costs increase as the wind QF defers 10 MW of the proxy wind resource in Utah. The QF is credited for avoided capital costs and fixed costs, net of the benefits of the deferred portion of that wind resource within the GRID model. The cost of the deferred wind resource is net of production tax credits during the first ten years, so avoided costs increase in 2033 when its production tax credits have expired. Because the generation profile of the QF and the deferred wind resource are the same, the decline in system marginal costs in 2024 does not impact avoided costs for the wind resource, as the net impact is zero regardless of price.

Q. What are the main drivers of the avoided cost prices for solar resources shown in Figure 2?

A. Through 2023, both fixed-tilt and tracking solar QFs defer FOTs and have avoided cost prices that primarily reflect the value of redispatching existing PacifiCorp resources, with some reductions in market purchases and increases in market sales. Starting in 2024, both types of solar QFs defer proxy solar and storage resources located in northern Utah. While the QF is credited for avoided capital costs and fixed costs, the addition of more than 2,000 MW of solar resources in that year results in a reduction in the value of solar energy relative to the prior year. This is despite the addition of more than 500 MW of battery storage. Because a fixed-tilt solar QF has more generation during the middle of the day when solar generation is highest across the system and LOLP events are less likely, it has a lower capacity contribution and relatively lower energy value that results in a decline in the avoided cost in 2024 despite the inclusion of avoided capital and fixed costs. The somewhat higher capacity contribution of tracking solar results in avoided costs that are essentially flat, as the avoided capital and fixed costs are offset by reduced energy values associated with the increased supply of solar resources.

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

A. The Proxy/PDDRR methodology reasonably captures the specific operational characteristics of base load and solar QFs. The Company requests that the avoided cost rates published in Schedule 37 be updated to reflect the avoided costs shown for these resource types. The deferral of Wyoming wind resources and the Gateway South transmission line do not result in accurate avoided costs for Utah wind QFs, which led the Company to propose a non-routine change to have Utah wind QFs defer a Utah wind resource. Additional support for this proposed change is provided in the next section. The proposed non-routine change to wind resource pricing does not impact the Schedule 37 avoided costs for the other resource types.

NON-ROUTINE UPDATE TO WIND PRICING

Q. Does the current Proxy/PDDRR Methodology result in accurate avoided costs for Utah wind QFs?

A. No. A premise of PURPA is that avoided costs may not exceed a utility's "incremental cost of alternative electric energy." The Proxy/PDDRR methodology identifies specific sources of alternative electric energy (and capacity), and calculates avoided costs based on those alternatives. The capacity component is captured via partial displacement of proxy resources from the IRP preferred portfolio, while the energy component is captured within the rebalancing of loads and resources after the addition of the QF and the removal of displaced proxy resource by the GRID model. In this instance, the capacity-equivalent displacement of Wyoming wind and transmission does not result in avoided cost prices that are consistent with the costs retail customers would otherwise incur to acquire capacity and energy equivalent to a Utah wind QF.

Q. What is the Company's proposed non-routine methodology change to the pricing of Utah wind QFs?

A. Utah wind resources will first be assumed to displace the 2023 customer preference Utah wind resources from the 2019 IRP preferred portfolio. If those Utah wind resources are fully displaced, the Company will continue to use the costs and characteristics of those resources to calculate avoided costs, by adding Utah wind resources with equivalent capacity to the QF in the base study and removing them in the avoided cost study when the QF is added.

Q. Did the 2019 IRP include the option to build Utah wind resources?

A. Yes. The supply-side table for the 2019 IRP includes costs and operational characteristics for Utah wind resources.

Q. Were any Utah wind resources selected as part of the 2019 IRP preferred portfolio?

A. Yes. The 2019 IRP preferred portfolio includes 69 MW of Utah wind resources in 2023 that were selected to meet customer preference requirements for new renewable resources. These resources were assumed to qualify for a 60 percent production tax credit by achieving commercial operation on or before December 31, 2022. With recent changes in tax law, wind resources achieving commercial operation on or before December 31, 2024 can achieve that same level of production tax credits.

Q. Are the Utah wind resources in the 2019 IRP preferred portfolio cost-effective?

A. No. These resources were not selected in the 2019 IRP sensitivity (S-07) that removed the customer preference requirement and system costs also decreased. Taken together, this indicates that the Utah wind resources were not cost-effective.

Q. How does the Proxy/PDDRR methodology treat resources that are not cost-effective?

A. Resources which are not cost-effective are not eligible for deferral under the Proxy/PDDRR methodology, as it would result in retail customers paying more than the costs they would otherwise incur. The original intent when this rule was proposed was that Utah customers would not pay for renewable resources intended to meet renewable portfolio standard obligations in other states. While those resources may be cost-effective for the other states, Utah customers do not have the same obligations and would not incur those same costs. Similarly, retail customers as a whole should not incur incremental costs for renewable resources added to meet the renewable resource preferences of individual customers.

Q. Can deferral of the customer preference Utah wind resource in the 2019 IRP preferred portfolio help assess the accuracy of avoided cost pricing?

A. Yes. Because the Utah wind resource in the 2019 IRP is expected to cost more than the capacity and energy benefits it provides, its costs should represent an upper bound on what it is reasonable for customers to incur for comparable capacity and energy.

Q. Does a Utah wind QF provide capacity and energy benefits that are comparable to the Utah wind resource in the 2019 IRP preferred portfolio?

A. Yes. The Company has modeled the generic Utah wind QF used to determine Schedule 37 avoided cost prices using the same generation profile as the Utah wind resource from the 2019 IRP preferred portfolio. This also means that both resources have the same capacity contribution.

Q. Are there any other methods available to evaluate the avoided costs of a Utah wind QF?

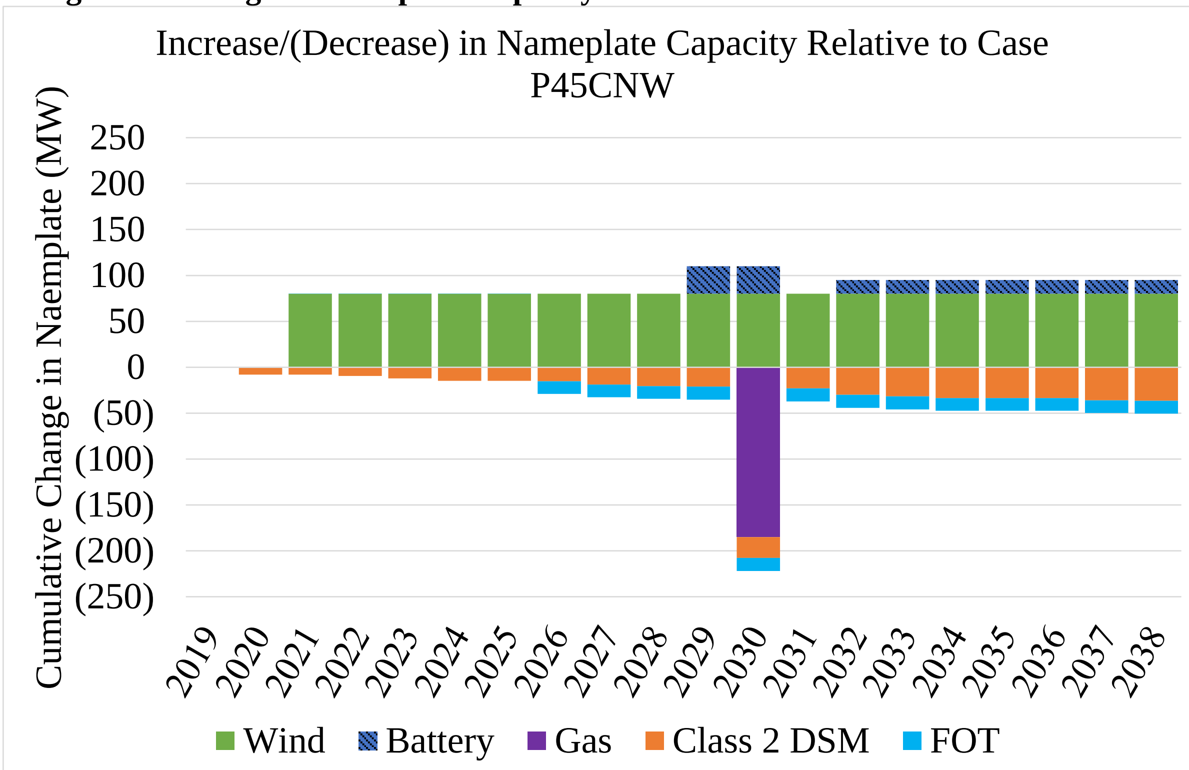
A. Yes. The Company uses the techniques and models developed in its IRP to evaluate offers received in response to requests for proposals ("RFPs") and other long-term resource opportunities. To better quantify the value of Utah wind resources, the Company examined the impacts of adding an 80 MW Utah wind resource on the 2019 IRP preferred portfolio. An 80 MW wind resource was selected rather than the 10 MW resource size typically used in Schedule 37 because the impact of small changes can be overwhelmed given the size of the Company's overall portfolio and the available resource alternatives.

Q. How was the IRP study prepared?

A. The Company began with the pre-reliability portfolio for scenario P-45CNW which ultimately was reflected in the preferred portfolio. The 80 MW Utah wind resource was added from 2021 through the end of the study period and the deterministic reliability analysis was repeated for all 16 years assessed in the 2019 IRP (2023 to 2038). The addition of the Utah wind resource results in additional supply during the hours when it is expected to deliver, including in the hours with the greatest shortfalls, and reduces those shortfalls. Through 2027 there was no change in reliability requirements as the preferred portfolio did not have an incremental requirement in those years. From 2028 through 2038, the incremental reliability requirement in the summer dropped by an average of 24 MW, relative to the preferred portfolio, which equates to a capacity contribution of 30 percent for the 80 MW Utah wind resource. The impact varies significantly from year to year as the wind generation profile doesn’t always line up with the highest net load conditions.

Next, resulting reliability requirements were added to the pre-reliability version of the preferred portfolio with the Utah wind resource, and the System Optimizer model was used to select reliability resources sufficient to meet those reliability requirements. Because the reliability requirement is lower than in the preferred portfolio, fewer reliability resources are needed. The resulting portfolio changes relative to the preferred portfolio are shown in Figure 3. The Utah wind resource is shown in green starting in 2021. Between 2028 and 2038, the addition of the Utah wind resource reduces energy efficiency by 29 MW, delays one SCCT by one year, avoids 14 MW of FOTs, and has an average increase in batteries of 15 MW. Much of the avoided energy efficiency was acquired as early as 2020, so there are also benefits prior to the first change in the reliability requirement.

Figure 3: Change in Nameplate Capacity Relative to the Preferred Portfolio



Q. Have you prepared system costs based on the Utah wind portfolio described above?

A. Yes. The Company ran the portfolio described in Figure 3 in its Planning and Risk ("PaR") model, using the same stochastic modeling used to evaluate portfolio performance and identify the preferred portfolio in the 2019 IRP. The PaR model evaluated the portfolio using the September 2018 forward prices from the 2019 IRP, with medium gas prices, and no greenhouse gas price, as this is most consistent with the Company's official forward price curve used to determine avoided costs under the approved Proxy/PDDRR methodology.

Q. How do the market prices in the IRP analysis compare to those used for avoided costs?

A. The Company's December 2019 official forward price curve which was used to prepare the Proxy/PDDRR methodology avoided costs discussed in this filing is generally lower for both natural gas and power, relative to the September 2018 prices used in the 2019 IRP, as shown in Figures 4 and 5. As a result, the Sept. 2018 prices used in the 2019 IRP would generally be expected to produce higher avoided costs than the December 2019 prices, as avoided gas generation or market purchases will have higher values.

Figure 4: Henry Hub Natural Gas Prices

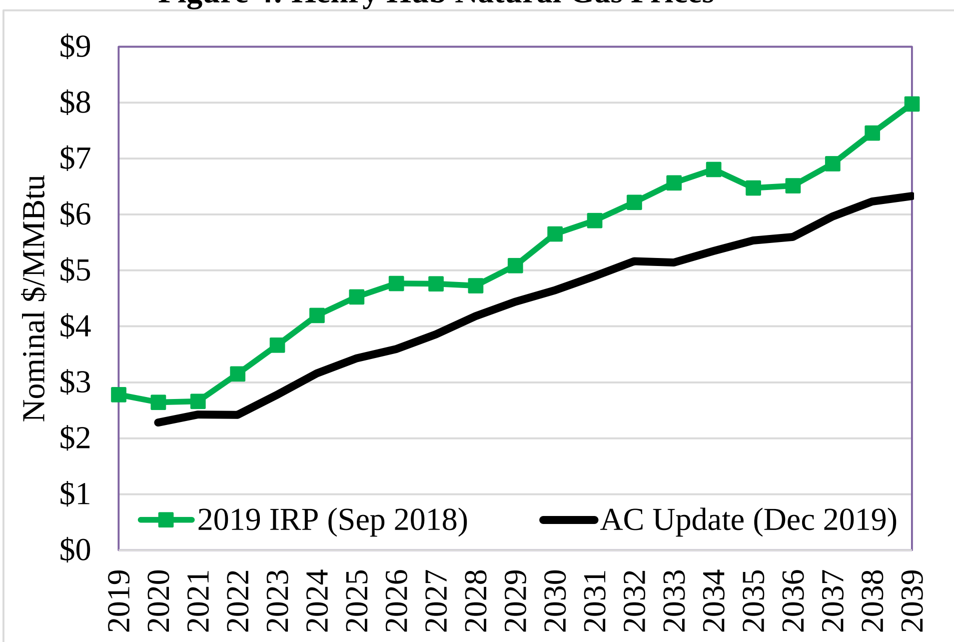
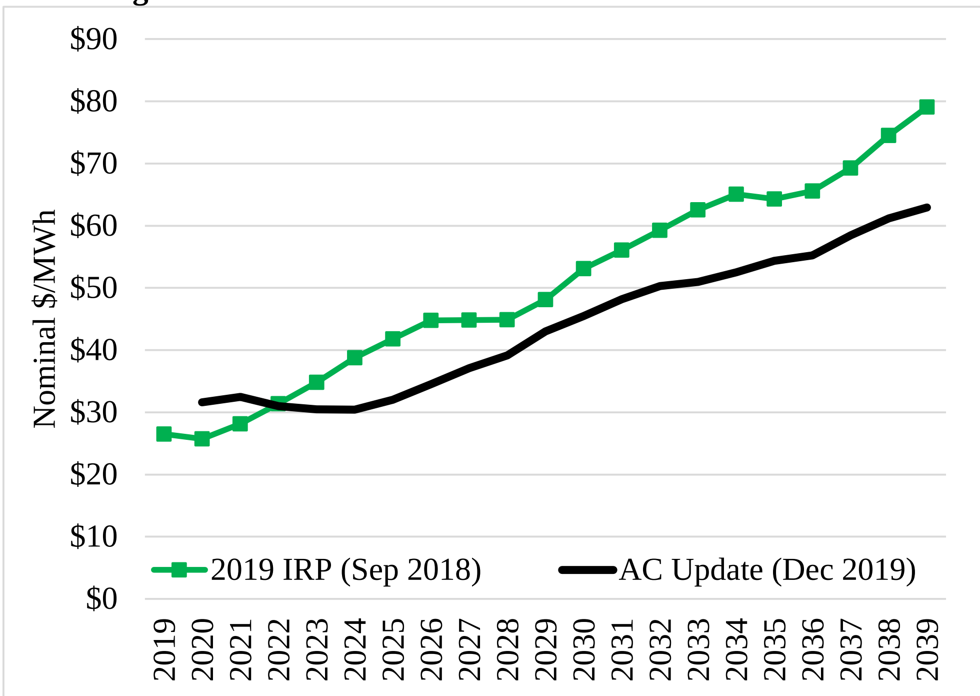


Figure 5: Mid-Columbia and Palo Verde Flat Power Prices



Q. What avoided costs do the IRP models produce for a Utah wind resource?

A. The PaR model avoided costs for a Utah wind resource are shown in Figure 6, along with the Proxy/PDDRR results for comparison. The IRP model results are shown both on a nominal basis and on a real-levelized basis which smooths out the impacts of resource portfolio changes from year to year. Table 3 summarizes the levelized avoided cost prices for wind resources under the different methodologies, based on various start dates.

Figure 6: IRP Model and Proxy/PDDRR Wind Prices

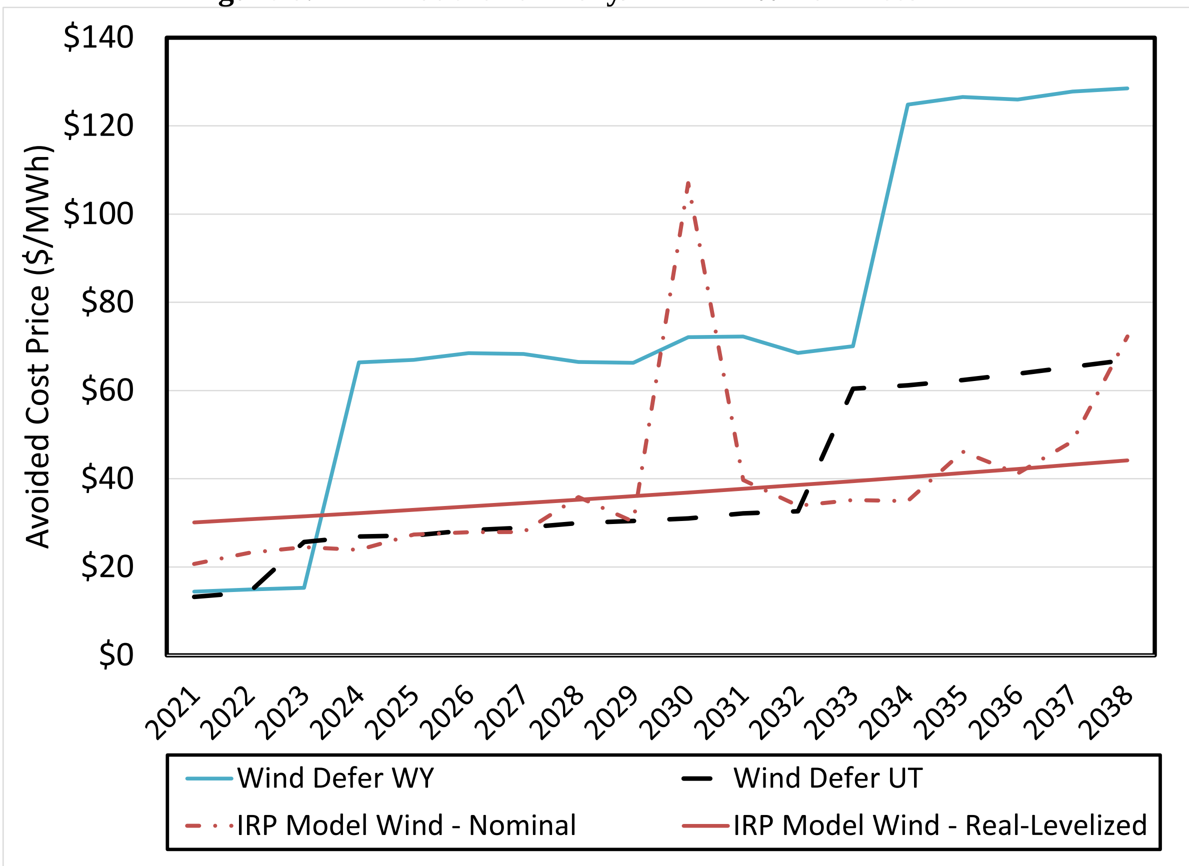


Table 3: Wind Avoided Cost by Start Date

15 Year Nominal Levelized Prices @ 6.92% Discount Rate ($/MWh)			
	Start Date		
Resource	**2021**	**2022**	**2023**
Wind Defer WY	$57.73	$65.19	$73.20
Wind Defer UT	$30.07	$33.26	$36.62
IRP Model Wind	$33.39	$35.09	$36.93

Q. What are the main drivers of the avoided cost prices for Utah wind resources based on the IRP model in Figure 6?

A. Through 2027, the portfolio with the Utah wind resource doesn't have a relative increase in reliability requirements versus the preferred portfolio, as the requirements were already zero. However, during this time period, the System Optimizer model identified energy efficiency that would no longer be needed in future years. In 2029 and 2030, battery capacity is 30 MW higher than in the preferred portfolio; however, this effect is more than offset by the one year delay of a 185 MW SCCT at Naughton from 2030 to 2031. The delay of the SCCT produces the large spike in avoided costs in 2030.

Q. Why does the avoid cost return to roughly its original level in 2031?

A. Under the Proxy/PDDRR methodology, the next deferrable resource is reduced in size through the remainder of the study period. In contrast, the IRP models produce portfolios with discrete thermal resources, rather than partially displaced capacity. In this instance, the Utah wind resource represents significantly less capacity than the SCCT, so it cannot defer the entire SCCT on its own, but when combined with earlier battery capacity, it is able to delay the entire SCCT for a year. In addition, some portion of the SCCT capacity may also have been above and beyond the system need in 2030, but was cost-effective in future years and had to be built as a complete unit. Since the SCCT is built one year later and its capital costs escalate at inflation, the cost associated with the SCCT in 2031 ends up being identical in both the preferred portfolio and the portfolio with the Utah wind resource. In 2031, the battery capacity in the preferred portfolio also catches up with that in the portfolio with the Utah wind resource, which also contributes to relatively stable pricing.

Q. Is it realistic for the 2030 avoided costs for Utah wind to be 250 to 300 percent higher than avoided costs in 2029 and 2031?

A. No. The 2019 IRP preferred portfolio includes two SCCT additions in 2030. The addition of the Utah wind allows one of those plants to be delayed by one year, but the fact that the Utah wind is able to push the portfolio over a tipping point is only possible because of the availability of stand-alone battery capacity and the fact that other resources in the preferred portfolio had already reduced the need for the SCCT in that year.

Consider an additional IRP model run with 40 MW of Utah wind, half of what was reflected in the results described above. If that 40 MW of Utah wind triggers the one year delay in the SCCT, its 2030 avoided cost is likely to be much higher as the savings from SCCT deferral are spread across half of the generation. The 2030 avoided cost of the second half of the Utah wind would then be lower by an equal and opposite amount, as the value of 80 MW has already been calculated. It is also just as likely that it is not until the second half of the Utah wind is added that the SCCT can be deferred, with resulting increases in avoided costs for the second resource. In that instance, while the first 40 MW of Utah wind would not be associated with the SCCT deferral, its contribution is still necessary for that deferral to occur, even though it wouldn’t show up in its avoided costs from the IRP models.

In both cases, the load and resource balance of the underlying portfolio is critical to the outcome. Between now and 2030, a relatively small decrease in load or a larger than expected resource acquisition could just as easily shift the SCCT into 2031, without any additional Utah wind. Because the timing of the need is uncertain, it would be inappropriate to enter a single year contract for power in 2030 based on this outcome. Similarly, it is appropriate to spread avoided costs from that year over a longer period, which is why the results have also been shown as a real-levelized value over the contract term.

Q. Are the IRP model results more accurate than the Proxy/PDDRR results?

A. Not necessarily. In the example above, the difference in avoided costs between the first

40 MW Utah wind resource and the second 40 MW Utah wind resource highlights the variations that can arise when models are forced to choose between discrete, rather than continuous, options. These outcomes are reliant upon a level of precision that is miniscule relative to the Company's potential high and low load cases, and the outcomes for the two halves of the Utah wind resource could easily be flipped.

As a result, for relatively small portfolio changes, the continuous deferral under the Proxy/PDDRR methodology is more likely to provide avoided costs that decline as additional QFs are added, consistent with the fundamentals of supply and demand, and which reasonably attribute value to each of the resources that contribute to a resource deferral, rather than just the last one. But for large portfolio changes, the IRP model results demonstrate that optimized portfolio outcomes can reflect changes in a variety of resource types and over extended time frames that can't be determined with the Proxy/PDDRR methodology.

Q. Is there a distinction between resources that have discrete sizes and those that can vary continuously between zero and a large value that is relevant to the Proxy/PDDRR methodology?

A. Yes. In the 2019 IRP, the models may select renewable resources and energy efficiency in continuous increments, such that they can be sized specifically to meet the need at the time. This is generally consistent with renewable resource construction, where including another wind turbine or panel of solar cells is relatively straightforward. In contrast, the IRP models only select thermal resources and transmission upgrades based on discrete, whole number quantities. For long-term planning purposes in the IRP, these assumptions are reasonable; however, when the IRP models are used to evaluate offers in an RFP, resource selection is limited to the discrete sizes of the bids on hand, rather than continuous quantities. As a result, when discrete items in the preferred portfolio are within the IRP action plan window, it may be worth reconsidering whether they should still be classified as "partially displaceable".

Q. Are there any items in the 2019 IRP preferred portfolio which may not be appropriate to consider "partially displaceable"?

A. Yes. The Gateway South transmission line is unlikely to be reconfigured to a slightly reduced size given technological constraints. Gateway South may or may not prove economic in combination with bids in the Company's upcoming RFP, but the choice will be between widely different outcomes: either Gateway South will be built, or it won't. As a result, the partial displacement calculation for Utah wind QFs under the approved Proxy/PDDRR methodology is unrealistic. Partial displacement is likewise inconsistent with the treatment of bids in an RFP, which are generally either a take it or leave it opportunity. Oftentimes, an intermediate option would be more economic, if it was technically feasible at a cost comparable to the unit cost of the overall project. While the Company's non-routine proposal renders partial displacement of Gateway South moot, the treatment of discrete items in the action plan window of the IRP may need to be revisited in the future.

Q. What do you recommend with regard to the Proxy/PDDRR methodology for wind resources?

A. The Company recommends that its proposed non-routine methodology change applicable to wind resources be adopted as follows. Utah wind resources will first be assumed to displace the 2023 customer preference Utah wind resources from the 2019

IRP preferred portfolio. If those Utah wind resources are fully displaced, the Company will continue to use the costs and characteristics of those resources to calculate avoided costs, by adding Utah wind resources with equivalent capacity to the QF in the base study and removing them in the avoided cost study with the QF added. This has been shown to reasonably approximate the results produced by the IRP models, is consistent with resource options and costs available for selection in the 2019 IRP, and as a result is more consistent with the customer indifference standard than the current implementation of the Proxy/PDDRR methodology for Utah wind QFs.

Q. Does this conclude your direct testimony?

A. Yes.

Proposed Tariff Sheets

Redlined Version

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Base Load Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During Calendar Year	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) Winter	Off-Peak Energy Prices (¢/kWh) Summer
Deliveries During Calendar Year	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) Winter	Off-Peak Energy Prices (¢/kWh) Summer
2020	1.378	2.744	1.255	1.291
2021	1.594	2.520	1.446	1.227
2022	1.558	2.596	1.383	1.330
2023	1.630	2.488	1.501	1.513
2024	1.153	1.538	1.089	1.108
2025	1.202	1.764	1.137	1.271
2026	2.784	4.546	2.645	3.280
2027	2.852	4.911	2.679	3.504
2028	3.235	5.222	3.077	3.854
2029	3.411	5.558	3.248	4.019
2030	3.354	5.577	3.174	4.131
2031	3.688	5.948	3.633	4.595
2032	4.196	6.365	4.137	5.042
2033	4.284	6.468	4.192	5.185
2034	4.481	6.609	4.429	5.353
2035	4.653	6.882	4.664	5.572
2036	4.756	7.130	4.738	5.771
2037	4.860	7.294	4.883	5.938
2038	4.949	7.433	4.981	6.052
2039	5.055	7.594	5.085	6.175
~~2019~~	~~2.578~~	~~4.679~~	~~2.402~~	~~2.261~~
~~2020~~	~~1.920~~	~~3.946~~	~~1.715~~	~~2.050~~
~~2021~~	~~1.816~~	~~3.618~~	~~1.685~~	~~2.038~~
~~2022~~	~~1.603~~	~~2.955~~	~~1.491~~	~~1.727~~
~~2023~~	~~1.691~~	~~2.952~~	~~1.565~~	~~1.789~~
~~2024~~	~~2.203~~	~~4.017~~	~~2.042~~	~~2.352~~
~~2025~~	~~2.367~~	~~4.467~~	~~2.194~~	~~2.718~~
~~2026~~	~~2.346~~	~~4.640~~	~~2.180~~	~~2.914~~
~~2027~~	~~2.630~~	~~4.666~~	~~2.421~~	~~2.992~~
~~2028~~	~~2.761~~	~~5.899~~	~~2.574~~	~~3.865~~

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

~~2029~~	~~3.147~~	~~6.703~~	~~2.947~~	~~4.443~~
~~2030~~	~~3.364~~	~~7.486~~	~~3.165~~	~~4.888~~
~~2031~~	~~3.545~~	~~7.903~~	~~3.359~~	~~5.300~~
~~2032~~	~~3.701~~	~~8.163~~	~~3.541~~	~~5.534~~
~~2033~~	~~3.878~~	~~9.145~~	~~3.740~~	~~6.047~~
~~2034~~	~~4.108~~	~~9.559~~	~~3.964~~	~~6.384~~
~~2035~~	~~4.168~~	~~10.716~~	~~4.040~~	~~6.664~~
~~2036~~	~~4.372~~	~~10.828~~	~~4.250~~	~~6.926~~
~~2037~~	~~4.459~~	~~11.241~~	~~4.355~~	~~6.839~~
~~2038~~	~~4.558~~	~~11.388~~	~~4.459~~	~~7.135~~

Levelized Prices (Nominal)

	~~On-Peak Energy Prices (¢/kWh)~~		~~Off-Peak Energy Prices (¢/kWh)~~	
	~~Winter~~	~~Summer~~	~~Winter~~	~~Summer~~
	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2021-2035) Nominal Levelized	2.618	4.118	2.500	2.954
~~15-year (2020-2034) Nominal Levelized~~	~~2.519~~	~~5.171~~	~~2.354~~	~~3.245~~

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Fixed Solar Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (1)	
Calendar Year	Winter	Summer	Winter	Summer
2020	1.129	1.813	1.025	0.846
2021	1.158	1.718	1.059	0.852
2022	1.224	1.815	1.094	0.947
2023	1.276	1.824	1.180	1.128
2024 (3)	0.815	1.323	0.769	0.950
2025	0.870	1.395	0.830	1.013
2026	0.945	1.551	0.900	1.120
2027	1.059	1.825	1.000	1.319
2028	1.298	2.095	1.238	1.562
2029	1.475	2.406	1.412	1.750
2030	1.167	1.948	1.104	1.428
2031	1.419	2.293	1.401	1.779
2032	1.706	2.594	1.682	2.073
2033	1.810	2.743	1.771	2.215
2034	1.863	2.762	1.845	2.257
2035	1.901	2.829	1.920	2.301
2036	2.165	3.268	2.156	2.654
2037	2.002	3.029	2.017	2.467
2038	2.186	3.303	2.212	2.713
2039	2.234	3.375	2.254	2.761
~~2019~~	~~2.155~~	~~3.379~~	~~1.914~~	~~1.669~~
~~2020~~	~~1.572~~	~~2.790~~	~~1.390~~	~~1.504~~
~~2021~~	~~1.415~~	~~2.410~~	~~1.322~~	~~1.379~~
~~2022~~	~~1.294~~	~~2.305~~	~~1.213~~	~~1.364~~
~~2023~~	~~1.081~~	~~2.369~~	~~0.902~~	~~1.468~~
~~2024~~	~~1.672~~	~~2.995~~	~~1.552~~	~~1.888~~
~~2025~~	~~1.791~~	~~3.247~~	~~1.670~~	~~2.062~~
~~2026~~	~~1.875~~	~~3.312~~	~~1.741~~	~~2.195~~
~~2027~~	~~1.925~~	~~3.298~~	~~1.787~~	~~2.197~~
~~2028~~	~~2.112~~	~~4.226~~	~~1.998~~	~~2.799~~
~~2029~~	~~2.335~~	~~4.665~~	~~2.184~~	~~3.152~~
~~2030~~	~~3.859~~	~~7.451~~	~~3.640~~	~~4.988~~
~~2031~~	~~3.958~~	~~7.570~~	~~3.784~~	~~5.221~~

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

~~2032~~	~~4.092~~	~~7.798~~	~~3.952~~	~~5.409~~
~~2033~~	~~3.826~~	~~7.734~~	~~3.744~~	~~5.215~~
~~2034~~	~~3.949~~	~~7.949~~	~~3.865~~	~~5.330~~
~~2035~~	~~4.303~~	~~9.159~~	~~4.189~~	~~5.803~~
~~2036~~	~~4.451~~	~~9.255~~	~~4.361~~	~~6.159~~
~~2037~~	~~4.362~~	~~9.869~~	~~4.304~~	~~6.120~~
~~2038~~	~~4.545~~	~~9.920~~	~~4.491~~	~~6.321~~

Levelized Prices (Nominal)(3)

	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (2)	
	Winter	Summer	Winter	Summer
15-year (2021-2035) Nominal Levelized	1.255	1.953	1.194	1.368

(1): On- and off- peak prices are reduced by integration charges
(2): Levelized prices reflect a 0.5% annual degradation rate
(3): Renewable energy credits transfer to the utility starting in 2024

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Tracking Solar Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours
¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (1)	
Calendar Year	Winter	Summer	Winter	Summer
2020	1.173	1.827	1.086	0.860
2021	1.196	1.708	1.092	0.841
2022	1.227	1.794	1.096	0.936
2023	1.284	1.810	1.188	1.113
2024	1.166	1.920	1.100	1.366
2025	1.207	1.961	1.160	1.413
2026	1.287	2.146	1.226	1.539
2027	1.352	2.371	1.274	1.689
2028	1.584	2.592	1.519	1.916
2029	1.723	2.845	1.643	2.053
2030	1.459	2.464	1.377	1.800
2031	1.723	2.822	1.709	2.172
2032	1.946	3.003	1.912	2.379
2033	2.020	3.108	1.971	2.492
2034	2.077	3.126	2.062	2.537
2035	2.205	3.328	2.209	2.692
2036	2.244	3.442	2.230	2.780
2037	2.246	3.448	2.260	2.799
2038	2.433	3.733	2.457	3.044
2039	2.486	3.814	2.505	3.101

Levelized Prices (Nominal)(3)

	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (2)	
	Winter	Summer	Winter	Summer
15-year (2021-2035) Nominal Levelized	1.467	2.307	1.397	1.622

(1): On- and off- peak prices are reduced by integration charges
(2): Levelized prices reflect a 0.5% annual degradation rate
(3): Renewable energy credits transfer to the utility starting in 2024

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Wind Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (1)	
Calendar Year	Winter	Summer	Winter	Summer
2020	1.112	2.047	1.007	1.006
2021	1.317	2.157	1.213	1.082
2022	1.457	2.193	1.301	1.196
2023	2.289	4.211	2.108	2.724
2024	2.473	3.828	2.339	2.874
2025	2.499	3.817	2.388	2.867
2026	2.589	4.064	2.474	3.006
2027	2.581	4.315	2.458	3.141
2028	2.726	4.180	2.608	3.266
2029	2.781	4.294	2.664	3.250
2030	2.800	4.429	2.657	3.421
2031	2.864	4.434	2.828	3.544
2032	2.945	4.387	2.932	3.519
2033	5.450	8.020	5.385	6.647
2034	5.551	7.906	5.526	6.692
2035	5.641	8.048	5.694	6.737
2036	5.758	8.362	5.744	6.975
2037	5.858	8.573	5.916	7.130
2038	5.954	8.817	6.091	7.279
2039	6.101	8.920	6.195	7.463

~~Deliveries During~~	~~On-Peak Energy Prices (¢/kWh)~~		~~Off-Peak Energy Prices (¢/kWh) (1)~~	
~~Calendar Year~~	~~Winter~~	~~Summer~~	~~Winter~~	~~Summer~~
~~2019~~	~~2.287~~	~~4.096~~	~~2.066~~	~~1.994~~
~~2020~~	~~1.788~~	~~3.523~~	~~1.594~~	~~1.811~~
~~2021~~	~~1.604~~	~~3.159~~	~~1.480~~	~~1.780~~
~~2022~~	~~1.479~~	~~2.637~~	~~1.375~~	~~1.551~~
~~2023~~	~~1.483~~	~~2.496~~	~~1.385~~	~~1.520~~
~~2024~~	~~2.036~~	~~3.711~~	~~1.864~~	~~2.254~~
~~2025~~	~~2.224~~	~~3.992~~	~~2.023~~	~~2.400~~
~~2026~~	~~2.323~~	~~4.125~~	~~2.124~~	~~2.597~~
~~2027~~	~~2.453~~	~~4.157~~	~~2.219~~	~~2.688~~
~~2028~~	~~2.331~~	~~5.309~~	~~2.205~~	~~3.493~~
~~2029~~	~~2.931~~	~~6.352~~	~~2.698~~	~~4.197~~
~~2030~~	~~4.273~~	~~8.147~~	~~3.958~~	~~5.453~~
~~2031~~	~~4.331~~	~~8.238~~	~~4.046~~	~~5.586~~
~~2032~~	~~4.379~~	~~8.180~~	~~4.134~~	~~5.628~~
~~2033~~	~~4.724~~	~~9.302~~	~~4.497~~	~~6.297~~

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

~~2034~~	~~4.843~~	~~9.477~~	~~4.607~~	~~6.458~~
~~2035~~	~~4.919~~	~~10.382~~	~~4.694~~	~~6.580~~
~~2036~~	~~5.027~~	~~10.365~~	~~4.809~~	~~6.767~~
~~2037~~	~~5.009~~	~~11.196~~	~~4.829~~	~~6.912~~
~~2038~~	~~5.174~~	~~11.160~~	~~4.999~~	~~7.081~~

Levelized Prices (Nominal)

	On Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2021-2035) Nominal Levelized	2.751	4.264	2.645	3.180

(1): On- and off- peak prices are reduced by integration charges
(2): Renewable energy credits transfer to the utility starting in 2023

Proposed Tariff Sheets

Clean Version

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Base Load Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
Calendar Year	Winter	Summer	Winter	Summer
Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
Calendar Year	Winter	Summer	Winter	Summer
2020	1.378	2.744	1.255	1.291
2021	1.594	2.520	1.446	1.227
2022	1.558	2.596	1.383	1.330
2023	1.630	2.488	1.501	1.513
2024	1.153	1.538	1.089	1.108
2025	1.202	1.764	1.137	1.271
2026	2.784	4.546	2.645	3.280
2027	2.852	4.911	2.679	3.504
2028	3.235	5.222	3.077	3.854
2029	3.411	5.558	3.248	4.019
2030	3.354	5.577	3.174	4.131
2031	3.688	5.948	3.633	4.595
2032	4.196	6.365	4.137	5.042
2033	4.284	6.468	4.192	5.185
2034	4.481	6.609	4.429	5.353
2035	4.653	6.882	4.664	5.572
2036	4.756	7.130	4.738	5.771
2037	4.860	7.294	4.883	5.938
2038	4.949	7.433	4.981	6.052
2039	5.055	7.594	5.085	6.175

Levelized Prices (Nominal)

	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2021-2035) Nominal Levelized	2.618	4.118	2.500	2.954

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Fixed Solar Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours
¢/kWh

Non-Levelized Prices

Deliveries During Calendar Year	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) (1) Winter	Off-Peak Energy Prices (¢/kWh) (1) Summer
2020	1.129	1.813	1.025	0.846
2021	1.158	1.718	1.059	0.852
2022	1.224	1.815	1.094	0.947
2023	1.276	1.824	1.180	1.128
2024 (3)	0.815	1.323	0.769	0.950
2025	0.870	1.395	0.830	1.013
2026	0.945	1.551	0.900	1.120
2027	1.059	1.825	1.000	1.319
2028	1.298	2.095	1.238	1.562
2029	1.475	2.406	1.412	1.750
2030	1.167	1.948	1.104	1.428
2031	1.419	2.293	1.401	1.779
2032	1.706	2.594	1.682	2.073
2033	1.810	2.743	1.771	2.215
2034	1.863	2.762	1.845	2.257
2035	1.901	2.829	1.920	2.301
2036	2.165	3.268	2.156	2.654
2037	2.002	3.029	2.017	2.467
2038	2.186	3.303	2.212	2.713
2039	2.234	3.375	2.254	2.761

Levelized Prices (Nominal)(3)

	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) (2) Winter	Off-Peak Energy Prices (¢/kWh) (2) Summer
15-year (2021-2035) Nominal Levelized	1.255	1.953	1.194	1.368

(1): On- and off- peak prices are reduced by integration charges
(2): Levelized prices reflect a 0.5% annual degradation rate
(3): Renewable energy credits transfer to the utility starting in 2024

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Tracking Solar Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During Calendar Year	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) (1) Winter	Off-Peak Energy Prices (¢/kWh) (1) Summer
2020	1.173	1.827	1.086	0.860
2021	1.196	1.708	1.092	0.841
2022	1.227	1.794	1.096	0.936
2023	1.284	1.810	1.188	1.113
2024	1.166	1.920	1.100	1.366
2025	1.207	1.961	1.160	1.413
2026	1.287	2.146	1.226	1.539
2027	1.352	2.371	1.274	1.689
2028	1.584	2.592	1.519	1.916
2029	1.723	2.845	1.643	2.053
2030	1.459	2.464	1.377	1.800
2031	1.723	2.822	1.709	2.172
2032	1.946	3.003	1.912	2.379
2033	2.020	3.108	1.971	2.492
2034	2.077	3.126	2.062	2.537
2035	2.205	3.328	2.209	2.692
2036	2.244	3.442	2.230	2.780
2037	2.246	3.448	2.260	2.799
2038	2.433	3.733	2.457	3.044
2039	2.486	3.814	2.505	3.101

Levelized Prices (Nominal)(3)

	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) (2) Winter	Off-Peak Energy Prices (¢/kWh) (2) Summer
15-year (2021-2035) Nominal Levelized	1.467	2.307	1.397	1.622

(1): On- and off- peak prices are reduced by integration charges
(2): Levelized prices reflect a 0.5% annual degradation rate
(3): Renewable energy credits transfer to the utility starting in 2024

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Wind Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (1)	
Calendar Year	Winter	Summer	Winter	Summer
2020	1.112	2.047	1.007	1.006
2021	1.317	2.157	1.213	1.082
2022	1.457	2.193	1.301	1.196
2023	2.289	4.211	2.108	2.724
2024	2.473	3.828	2.339	2.874
2025	2.499	3.817	2.388	2.867
2026	2.589	4.064	2.474	3.006
2027	2.581	4.315	2.458	3.141
2028	2.726	4.180	2.608	3.266
2029	2.781	4.294	2.664	3.250
2030	2.800	4.429	2.657	3.421
2031	2.864	4.434	2.828	3.544
2032	2.945	4.387	2.932	3.519
2033	5.450	8.020	5.385	6.647
2034	5.551	7.906	5.526	6.692
2035	5.641	8.048	5.694	6.737
2036	5.758	8.362	5.744	6.975
2037	5.858	8.573	5.916	7.130
2038	5.954	8.817	6.091	7.279
2039	6.101	8.920	6.195	7.463

Levelized Prices (Nominal)

	On Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2021-2035) Nominal Levelized	2.751	4.264	2.645	3.180

(1): On- and off- peak prices are reduced by integration charges
(2): Renewable energy credits transfer to the utility starting in 2023

Appendix 1

Table 1
2019 IRP Update Preferred Portfolio
PacifiCorp's 2019 IRP, Volume I – Table 8.18 – 2019 Preferred Portfolio page 258

		Capacity (MW)																				Resource Totals 1/	
	Resource	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**10-year**	**20-year**
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
East	**Expansion Resources**																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,040	-	-	-	-	-	-	-	-	-	1,040
	Wind, UT	-	-	-	-	69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	69	69
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	60
	Total Wind	-	-	-	-	69	1,920	-	-	-	-	-	1,040	-	60	-	-	-	-	-	-	1,989	3,089
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	231	-	-	-	-	-	500	-	-	-	-	-	-	-	-	231	731
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	3	674	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	3	904	-	-	-	-	-	500	-	-	-	-	-	-	909	-	1,131	2,540
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	37.3
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	1.2	-	6.7
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	3.7	10.5	136.5	44.6	354.1
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	65	65	62	57	56	52	52	48	36	32	25	22	23	656	1,058
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	18	17	16	15	13	12	11	9	8	7	5	5	146	248
	Energy Efficiency Total	74	83	85	88	92	92	91	90	90	87	80	77	72	70	65	49	45	35	30	32	870	1,423
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	-	195.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	-	-	-	-	-	150.0	-	180.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	88	300	199	174	206	298	300	300	300	300	300	9	138

West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind+Storage, YK	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Total Wind	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	395	-	-	-	-	-	-	-	-	-	-	-	419	-	-	395	815
	Total Solar	-	-	-	-	-	1,249	-	-	-	-	359	-	-	-	475	-	-	419	-	702	1,249	3,205
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	48.8	32.1	-	90.2
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	41	46	43	41	41	38	35	32	31	30	26	26	25	25	24	23	405	680
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	111	179
	Energy Efficiency Total	52	49	48	55	55	59	56	54	54	51	46	43	42	40	35	33	33	30	29	28	533	892
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	210	-	-	60	-	-	-	-	-	180	-	450
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	75	45	-	-	-	-	-	-	-	-	-	75	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	75	-	-	60	-	-	-	-	-	60	-	195
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	131	126	191	264	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	977	1,074	1,075	500	782
	FOT West - Winter	151	131	268	303	314	44	51	53	100	232	222	173	192	128	63	-	35	-	-	-	165	123
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	299	206	237	4,225	155	336	143	318	1,063	2,038	144	303	574	82	93	488	2,355	1,530		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	175	177	244	364	1,394	1,597	1,447	1,441	1,409	1,435	1,375	1,410	1,277	1,374	1,375		
	Total Annual Additions	1,279	982	1,060	1,012	1,049	4,400	333	580	507	1,712	2,661	3,485	1,584	1,712	2,010	1,457	1,503	1,765	3,729	2,905		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Contracts Queue						
No.	Signed Contracts	Partial Displacement	Name plate	CF	Capacity Contribution	Start Date
1	Cypress Creek Renewables - Merrill Solar LLC	-1.5	-10.0		14.9%	2020 01 01
2	OR Solar 5, LLC (Merrill Solar) (ORSOLAR5 PPA QF)	-1.2	-8.0		14.9%	2020 01 01
3	Graphite Solar I	4.9	80.0		6.1%	2022 01 01
4	Mariah Wind	-5.8	-10.0		57.5%	2020 01 01
5	Orem Family wind	-5.8	-10.0		57.5%	2020 01 01
Total Signed MW		-9.28	42.00			

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	Capacity Factor (%)	Capacity Contribution (%)		
Summer/Winter:	Annual	S	W	
Solar & Storage				
Idaho Falls, ID	28%	33%	37%	Solar_IRP_ID_ST
Lakeview, OR	29%	35%	39%	Solar_IRP_OR_ST
Milford, UT	32%	30%	48%	Solar_IRP_UT_ST
Yakima, WA	25%	33%	34%	Solar_IRP_YK_ST
Rock Springs, WY	30%	31%	43%	Solar_IRP_WY_ST
Wind & Storage				
Pocatello, ID	37%	38%	50%	Wind_Goshen_W2
Arlington, OR	37%	77%	44%	Wind_I_OR
Monticello, UT	29%	37%	44%	Wind_I_UT
Goldendale, WA	37%	76%	44%	Wind_I_WA
Medicine Bow, WY	44%	32%	58%	Wind_I_WYAE

Table N.4 – Final CF Method Capacity Contribution Values for Wind, Solar, and Storage

	Capacity Factor (%)	Capacity Contribution (%)		
Summer/Winter:	Annual	S	W	
Solar				
Idaho Falls, ID	28%	12%	13%	Solar_IRP_ID_ST
Lakeview, OR	29%	15%	14%	Solar_IRP_OR_ST
Milford, UT	32%	10%	23%	Solar_IRP_UT_ST
Yakima, WA	25%	12%	10%	Solar_IRP_YK_ST
Rock Springs, WY	30%	11%	19%	Solar_IRP_WY_ST
Wind				
Pocatello, ID	37%	19%	27%	Wind_Goshen_W2
Arlington, OR	37%	57%	21%	Wind_I_OR
Monticello, UT	29%	18%	22%	Wind_I_UT
Goldendale, WA	37%	57%	21%	Wind_I_WA
Medicine Bow, WY	44%	13%	35%	Wind_I_WYAE
Stand-alone Storage				
2 hour duration		78%	89%	
4 hour duration		94%	100%	
9 hour duration		98%	100%	

Table 3
Comparison between Proposed and Current Avoided Costs

	BASE LOAD			WIND			SOLAR FIXED			SOLAR TRACKING		
Year	Proposed ($/MWH)	Current ($/MWH)	Total Difference ($/MWH)	Proposed ($/MWH)	Current ($/MWH)	Total Difference ($/MWH)	Proposed ($/MWH)	Current ($/MWH)	Total Difference ($/MWH)	Proposed ($/MWH)	Current ($/MWH)	Total Difference ($/MWH)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
			(a) - (b)			(d) - (e)			(g) - (h)			(j) - (k)
2020	$15.85	$22.58	($6.73)	$11.63	$19.38	($7.74)	$13.13	$19.28	($6.15)	$13.47	$21.58	($8.11)
2021	$16.70	$21.48	($4.78)	$13.25	$17.96	($4.70)	$13.02	$17.13	($4.10)	$13.17	$19.76	($6.59)
2022	$16.68	$18.41	($1.74)	$14.26	$16.03	($1.77)	$13.77	$16.05	($2.28)	$13.70	$16.92	($3.22)
2023	$17.36	$19.05	($1.69)	$25.69	$15.82	$9.87	$14.27	$14.89	($0.62)	$14.29	$15.56	($1.27)
2024	$12.00	$25.17	($13.18)	$26.91	$22.35	$4.56	$9.77	$20.86	($11.09)	$14.28	$22.68	($8.40)
2025	$12.98	$27.61	($14.63)	$27.13	$24.13	$3.00	$10.38	$22.50	($12.11)	$14.71	$24.36	($9.65)
2026	$31.46	$28.10	$3.36	$28.34	$25.41	$2.92	$11.41	$23.29	($11.89)	$15.89	$25.45	($9.56)
2027	$32.83	$30.03	$2.79	$28.91	$26.36	$2.54	$13.08	$23.57	($10.48)	$17.14	$25.60	($8.46)
2028	$36.52	$34.56	$1.96	$29.97	$29.45	$0.52	$15.57	$28.03	($12.46)	$19.43	$31.24	($11.81)
2029	$38.55	$39.45	($0.90)	$30.42	$35.85	($5.42)	$17.76	$30.98	($13.22)	$21.18	$34.18	($13.00)
2030	$38.32	$43.01	($4.70)	$31.03	$49.31	($18.28)	$14.21	$50.28	($36.07)	$18.16	$56.52	($38.36)
2031	$42.28	$45.64	($3.36)	$32.16	$50.23	($18.08)	$17.13	$51.47	($34.34)	$21.30	$57.67	($36.37)
2032	$47.09	$47.58	($0.49)	$32.63	$50.72	($18.08)	$20.04	$53.17	($33.13)	$23.35	$59.71	($36.35)
2033	$47.98	$51.42	($3.44)	$60.44	$56.02	$4.42	$21.23	$51.24	($30.01)	$24.22	$58.08	($33.86)
2034	$49.92	$54.21	($4.28)	$61.20	$57.35	$3.85	$21.67	$52.75	($31.08)	$24.68	$59.38	($34.70)
2035	$52.08	$57.23	($5.15)	$62.36	$59.31	$3.05	$22.18	$59.00	($36.83)	$26.25	$67.22	($40.96)
2036	$53.44	$59.20	($5.76)	$63.81	$60.46	$3.36	$25.39	$60.48	($35.09)	$26.92	$68.52	($41.60)
2037	$54.81	$60.48	($5.67)	$65.37	$61.90	$3.47	$23.53	$61.84	($38.31)	$27.00	$69.87	($42.87)
2038	$55.85	$61.86	($6.01)	$66.95	$63.32	$3.63	$25.71	$63.27	($37.57)	$29.27	$71.56	($42.30)
2039	$57.03	$63.16 (x)	($6.13)	$68.29	$64.65 (x)	$3.64	$26.25	$64.60 (x)	($38.35)	$29.89	$73.07 (x)	($43.18)

(x) Extrapolated

Discount Rate - 2019 IRP
6.920%

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
15 Year (2021 to 2035) Levelized Prices (Nominal) @ 6.92% Discount Rate												
$/MWH	$29.14	$32.69	($3.55)	$30.07	$31.49	($1.42)	$14.80	$30.15	($15.36)	$17.61	$33.48	($15.87)
15 Year (2022 to 2036) Levelized Prices (Nominal) @ 6.92% Discount Rate												
$/MWH	$31.47	$34.97	($3.51)	$33.26	$34.13	($0.87)	$15.41	$32.79	($17.38)	$18.47	$36.38	($17.91)
15 Year (2023 to 2037) Levelized Prices (Nominal) @ 6.92% Discount Rate												
$/MWH	$34.02	$37.80	($3.79)	$36.62	$37.22	($0.60)	$15.92	$35.78	($19.86)	$19.33	$39.84	($20.51)

	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	West Side	IRP - Wyo NE
	(a)	(b)
2018	$3.23	$2.60
2019	$4.31	$2.09
2020	$2.35	$1.84
2021	$2.29	$1.98
2022	$2.27	$2.01
2023	$2.48	$2.24
2024	$2.70	$2.48
2025	$2.99	$2.72
2026	$3.02	$2.89
2027	$3.26	$3.10
2028	$3.60	$3.41
2029	$3.92	$3.72
2030	$4.19	$3.98
2031	$4.46	$4.26
2032	$4.69	$4.52
2033	$4.74	$4.58
2034	$5.04	$4.82
2035	$5.19	$5.02
2036	$5.19	$5.07
2037	$5.55	$5.43

Source

Official Forward Price Curve dated December 31 2019

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	$35.89	$40.61	$23.72	$27.50
2019	$37.81	$32.15	$35.77	$25.72
2020	$34.23	$39.03	$24.50	$25.99
2021	$36.33	$39.47	$24.46	$26.79
2022	$34.47	$37.32	$23.93	$25.60
2023	$33.09	$36.56	$21.98	$27.96
2024	$31.76	$36.60	$20.02	$30.99
2025	$32.43	$39.42	$20.53	$33.47
2026	$35.73	$42.15	$22.02	$35.72
2027	$39.08	$45.05	$23.99	$37.58
2028	$41.01	$46.90	$26.13	$40.11
2029	$45.41	$51.27	$28.78	$43.67
2030	$48.73	$53.40	$30.66	$45.77
2031	$49.84	$57.07	$32.04	$50.86
2032	$51.59	$59.49	$33.63	$53.70
2033	$52.76	$59.91	$34.29	$54.03
2034	$53.76	$61.64	$35.71	$56.16
2035	$54.70	$63.98	$36.98	$58.98
2036	$55.98	$65.01	$37.34	$59.61
2037	$59.34	$68.35	$39.94	$63.10

Source

Official Forward Price Curve dated December 31 2019

Table 6
Integration Costs
$/MWH

Year	Wind Integration $/MWh	Solar Integration $/MWh		Company Official Inflation Forecast Dated December 2019 Year	Annual
2018	$0.50	$0.41		2018	2.4%
2019	$0.30	$0.25		2019	1.8%
2020	$0.39	$0.31		2020	1.9%
2021	$0.19	$0.15		2021	2.0%
2022	$0.27	$0.22		2022	2.5%
2023	$0.29	$0.24		2023	2.5%
2024	$0.35	$0.29		2024	2.4%
2025	$0.61	$0.50		2025	2.3%
2026	$0.45	$0.37		2026	2.3%
2027	$0.69	$0.56		2027	2.3%
2028	$0.93	$0.76		2028	2.3%
2029	$1.29	$1.05		2029	2.3%
2030	$1.61	$1.31		2030	2.2%
2031	$1.63	$1.32		2031	2.2%
2032	$1.74	$1.42		2032	2.2%
2033	$1.79	$1.45		2033	2.1%
2034	$1.75	$1.42		2034	2.1%
2035	$1.72	$1.40		2035	2.1%
2036	$1.58	$1.28		2036	2.1%
2037	$1.61 (x)	$1.31 (x)		2037	2.1%
2038	$1.65 (x)	$1.34 (x)		2038	2.1%
2039	$1.68 (x)	$1.37 (x)		2039	2.1%
2040	$1.72 (x)	$1.40 (x)		2040	2.1%
2041	$1.75 (x)	$1.43 (x)		2041	2.1%
2042	$1.79 (x)	$1.46 (x)		2042	2.1%

Appendix 2

ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES THAT QUALIFY FOR SCHEDULE NO. 37

UTAH – Apr 2020

ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES THAT QUALIFY FOR SCHEDULE NO. 37

UTAH – April 2020

OVERVIEW

Schedule 37 contains avoided cost prices to be paid to small qualifying facilities ("QF") and applies to QFs with a design capacity of 1 MW or less for qualifying cogeneration facilities and 3 MW or less for small power production facilities. Prices are available for a cumulative total of 25 MW. In compliance with the Commission's February 12, 2009, Order in Docket No. 08-035-78 on Net Metering Service, Schedule No. 37 avoided costs also establish the value or credit for net excess generation of large commercial customers under the Schedule No. 135 Net Metering Service.[1]

In compliance with Commission's January 23, 2018 Order in Docket No. 17-035-T07 and 17-035-37, the Company provides avoided costs rates for Schedule 37 reflecting the Proxy/PDDRR methodology applicable under Schedule 38 and with only signed QFs included in the QF queue.

The proposed rates are based on the Schedule 38 avoided cost inputs contained in the Company's April 9, 2020 quarterly avoided cost inputs compliance filing (2019.Q4 Filing). The proposed rates for wind resources incorporate the non-routine methodology change proposed by the Company in its January 10, 2020 avoided cost inputs compliance filing.

Consistent with the Commission's January 23, 2018 Order in Docket No. 17-035-T07 and 17-035-37, when a QF defers or avoids a renewable resource, the Company retains the QFs renewable energy credits (RECs) on behalf of ratepayers. When a QF's avoided capacity costs are not based on the costs of a renewable resource, the QF is entitled to the RECs associated with its output.

DESCRIPTION OF THE AVOIDED COST STUDY SUMMARY

"20-035-T04 RMP Appendix 1 - AC Study Summary 03-26-20" contains the summary of proposed avoided cost rates by QF type.

Table 1 presents the timing of deferrable resources as listed in Table 8.18 of 2019 Preferred Portfolio, Volume I. Table 1 shows the renewable resources the Company plans to acquire over the 20-year planning period.

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1 Docket No. 08-035-78, February 12, 2009 Order, U.P.S.C 24 (2009).

The timing of the deficiency period for a baseload QF is determined based on the next deferrable thermal resource that has not been already displaced by signed contracts. **Table 2** shows the current queue of signed or terminated contracts after the 2019 IRP was prepared. A 10 MW baseload QF displaces FOTs for 2020-2025 and 10.3 MW of Naughton simple cycle combustion turbine in 2026.

The deficiency period for a wind QF is based on the next deferrable IRP wind resource that has not been already displaced by signed wind contracts. Based on the current signed contracts and the Company's proposed non-routine methodology update, a 10 MW incremental wind QF partially displaces 10 MW of Utah wind resource starting in 2023. The Company retains 100% of the RECs starting in 2023.

The deficiency period for a tracking solar QF is based on the next deferrable IRP solar resource that has not been already displaced by signed solar contracts. A 10 MW tracking solar QF displaces 3.2 MW of solar with battery storage resource located in Utah North in 2024. The Company retains 100% of the RECs starting in 2024.

The deficiency period for a fixed-tilt solar QF is based on the next deferrable IRP solar resource that has not been already displaced by signed solar contracts. A 10 MW fixed-tilt solar QF displaces 1.4 MW of solar with battery storage resource located in Utah North in 2024. The Company retains 100% of the RECs starting in 2024.

In its Order in Docket No. 09-035-T14, the Commission directed the Company "to label Table 1 with the applicable planning reserve margin assumption (e.g., 12 or 15 percent) in all subsequent filings of Schedule No. 37 rates." The IRP uses planning reserves to account for operating reserves, regulating reserves, load forecast errors and other planning uncertainties. As shown on Table 1, the 2019 IRP utilized a 13 percent planning reserve margin.[2]

Table 3 presents a comparison of the proposed avoided cost rates to the currently effective rates for each QF type. **Table 4** and **Table 5** summarize natural gas and electricity market price forecasts used in the calculation of proposed rates in this filing.

DESCRIPTION OF AVOIDED COST STUDY WORKPAPERS

Baseload QF

The following supporting files contain calculations of avoided cost rates for Baseload QFs:

[2] 2019 Integrated Resource Plan. Volume II. Appendix I: Planning Reserve Margin Study. pg. 137 Available online at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf

20-035-T04 RMP CONF Workpaper 1a - GRID AC Study Thermal 03-26-20.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2020-2029

20-035-T04 RMP CONF Workpaper 1b - GRID AC Study Thermal 03-26-20.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2030-2038

20-035-T04 RMP Wkpr - Avoided Cost Study-Thermal 03-26-20.xlsx:

- **Table 1**: summarizes the annual avoided energy costs based on GRID runs and shows the calculation of the annual avoided capacity costs. A 10 MW baseload QF displaces FOTs for 2020-2025 and 10.3 MW of Naughton simple cycle combustion turbine in 2026.
- **Table 2:** summarizes monthly avoided energy costs based on the GRID runs
- **Table 4:** summarizes annual natural gas price forecasts for East and West side locations
- **Table 5:** shows the monthly calculation of avoided capacity costs and avoided energy costs. Total unit avoided costs ($/MWh) are calculated by summing the avoided energy cost dollars (based on GRID runs) and the avoided capacity cost dollars (based deferred resource fixed costs) and dividing by the generation of the QF.

20-035-T04 RMP Wkpr - QF Pricing Detail-Thermal 03-26-20.xlsx: contains the calculations of the monthly on-peak (HLH) and off-peak (LLH) avoided cost rates by spreading total monthly avoided cost dollars (both energy and capacity) based on projected Palo Verde ("PV") HLH and LLH market prices.

Wind QF
The following supporting files contain calculations of avoided cost rates for Wind QFs:

20-035-T04 RMP CONF Workpaper 1a - GRID AC Study Wind 03-26-20.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2020-2029.

20-035-T04 RMP CONF Workpaper 1b - GRID AC Study Wind 03-26-20.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2030-2038

20-035-T04 RMP Wkpr - Avoided Cost Study-Wind 03-26-20.xlsx:

- **Table 1:** summarizes the annual avoided energy costs based on GRID runs and shows the calculation of the annual avoided capacity costs. During the deficiency period, wind QF pricing reflects avoided fixed costs of 2023 Utah wind resources in the 2019 IRP preferred portfolio. PacifiCorp retains the RECs generated starting in 2023.

- **Table 2:** summarizes monthly avoided energy costs based on the GRID runs
- **Table 3:** shows the total resource cost information for each the planned new resources in 2019 IRP preferred portfolio. Total resource cost information included capital costs, and fixed and variable Operation and Maintenance (O&M) expenses, and tax credits if applicable.
- **Table 4:** summarizes annual natural gas price forecasts for East and West side locations
- **Table 5:** shows the monthly calculation of avoided capacity costs and avoided energy costs. Total unit avoided costs ($/MWh) are calculated by summing the avoided energy cost dollars (based on GRID runs) and the avoided capacity cost dollars (based deferred resource fixed costs) and dividing by the generation of the QF.

20-035-T04 RMP Wkpr - QF Pricing Detail-Wind 03-26-20.xlsx: contains the calculations of the monthly on-peak (HLH) and off-peak (LLH) avoided cost rates for a Wind QF by spreading total monthly avoided cost dollars (both energy and capacity) based on projected Palo Verde ("PV") HLH and LLH market prices.

Tracking Solar QF

The following supporting files contain calculations of avoided cost rates for Tracking Solar QFs:

20-035-T04 RMP CONF Workpaper 1a - GRID AC Study Solar T 03-26-20.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2020-2029

20-035-T04 RMP CONF Workpaper 1b - GRID AC Study Solar T 03-26-20.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2030-2038

20-035-T04 RMP Wkpr - Avoided Cost Study-Solar T 03-26-20.xlsx:

- **Table 1:** summarizes the annual avoided energy costs based on GRID runs and shows the calculation of the annual avoided capacity costs. During the deficiency period, solar QF pricing reflects avoided fixed costs of the 2024 Utah North solar with battery storage resource in the 2019 IRP preferred portfolio. PacifiCorp retains the RECs generated starting in 2024.
- **Table 2:** summarizes monthly avoided energy costs based on the GRID runs
- **Table 3:** shows the total resource cost information for each planned new resources in the 2019 IRP preferred portfolio. Total resource cost information included capital costs, and fixed and variable Operation and Maintenance (O&M) expenses, and tax credits if applicable.

- **Table 4:** summarizes annual natural gas price forecasts for East and West side locations
- **Table 5:** shows the monthly calculation of avoided capacity costs and avoided energy costs. Total unit avoided costs ($/MWh) are calculated by summing the avoided energy cost dollars (based on GRID runs) and the avoided capacity cost dollars (based deferred resource fixed costs) and dividing by the generation of the QF.

20-035-T04 RMP Wkpr - QF Pricing Detail-Solar T 03-26-20.xlsx: contains the calculations of the monthly on-peak (HLH) and off-peak (LLH) avoided cost rates for a tracking Solar QF by spreading total monthly avoided cost dollars (both energy and capacity) based on projected Palo Verde ("PV") HLH and LLH market prices.

<u>Fixed Solar QF</u>

The following supporting files contain calculations of avoided cost rates for Fixed Solar QFs:

20-035-T04 RMP CONF Workpaper 1a - GRID AC Study Solar F 03-26-20.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2020-2029

20-035-T04 RMP CONF Workpaper 1b - GRID AC Study Solar F 03-26-20.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2030-2038

20-035-T04 RMP Wkpr - Avoided Cost Study-Solar F 03-26-20.xlsx:

- **Table 1:** summarizes the annual avoided energy costs based on GRID runs and shows the calculation of the annual avoided capacity costs. During the deficiency period, solar QF pricing reflects avoided fixed costs of the 2024 Utah North solar with battery storage resource in the 2019 IRP preferred portfolio. PacifiCorp retains the RECs generated starting in 2024.
- **Table 2:** summarizes monthly avoided energy costs based on the GRID runs
- **Table 3:** shows the total resource cost information for each the planned new resources in 2019 IRP preferred portfolio. Total resource cost information included capital costs, and fixed and variable Operation and Maintenance (O&M) expenses, and tax credits if applicable.
- **Table 4:** summarizes annual natural gas price forecasts for East and West side locations
- **Table 5:** shows the monthly calculation of avoided capacity costs and avoided energy costs. Total unit avoided costs ($/MWh) are calculated by summing the avoided energy cost dollars (based on GRID runs) and the avoided capacity cost

dollars (based deferred resource fixed costs) and dividing by the generation of the QF.

20-035-T04 RMP Wkpr - QF Pricing Detail-Solar F 03-26-20.xlsx: contains the calculations of the monthly on-peak ("HLH") and off-peak ("LLH") avoided cost rates for a fixed Solar QF by spreading total monthly avoided cost dollars (both energy and capacity) based on projected Palo Verde ("PV") HLH and LLH market prices.

CERTIFICATE OF SERVICE

Docket No. 19-035-18

I hereby certify that on April 9, 2020, a true and correct copy of the foregoing was served by electronic mail to the following:

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