PACIFIC POWER
A DIVISION OF PACIFICORP

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August 9, 2019

VIA ELECTRONIC FILING

Mark L. Johnson
Executive Director and Secretary
Washington Utilities & Transportation Commission
621 Woodland Square Loop SE
Lacey, Washington 98503

Re: Docket U-161024—Pacific Power & Light Company's Compliance Filing

On June 12, 2019, the Washington Utilities and Transportation Commission (Commission) issued its Order R-597 adopting WAC 480-106-001 *et seq*. (Order). Utilities were directed to submit compliance filings no later than August 9, 2019, to provide revised tariffs that include estimated avoided cost pricing in compliance with the new requirements set forth in the rules. Pacific Power & Light Company (Pacific Power), a division of PacifiCorp, submits proposed Schedule QF in compliance with the Order, RCW 80-28-050, and WAC 480-07-880. This proposed tariff replaces Schedule 37 in its entirety. As a result of the new requirements, the company also encloses a revised standard qualifying facility (QF) power purchase agreement (PPA). The detailed revisions to these documents are set forth below. The company respectfully requests an effective date of November 1, 2019.

Fourth Revision of Sheet No. INDEX.2		Tariff Index
Twelfth Revision of Sheet No. INDEX.3		Tariff Index
NEW Sheet Nos. QF.1–QF.18	Schedule QF	Avoided Cost Purchases and Procedures for Qualifying Facilities
CANCEL Sheet No. 37.1	Schedule 37	Cogeneration and Small Power Production
CANCEL Sheet No. 37.2	Schedule 37	Cogeneration and Small Power Production

Standard Contract Avoided Cost Pricing

The company's revised Schedule QF provides updated, estimated avoided cost pricing. The updated pricing reflects the following assumptions made by the company.

Energy

WAC 480-106-040(1)(a) specifies that avoided energy cost must be based on the current forecast of market prices for power. PacifiCorp's hourly Mid-Columbia market prices from its most recent Official Forward Price Curve (OFPC, currently dated June 28, 2019) are proposed for this purpose. PacifiCorp selected the Mid-Columbia market as it has transmission rights from that market to its Washington retail load in Walla Walla and Yakima.

WAC 480-106-040(1)(a) also allows for differentiation of daily and seasonal peak and off-peak period prices. PacifiCorp is proposing on-peak and off-peak energy prices for summer and winter seasons, based on the daily and monthly patterns in its forecast of hourly Mid-Columbia market prices. The months with the highest average market prices are concentrated in the summer, with June through September representing the top four months in the year.[1] As discussed below, the months with the highest capacity value based on analysis and assumptions in the 2017 Integrated Resource Plan (IRP) are also within this period. In light of these factors, PacifiCorp is proposing a summer season which spans the months of June through September. The remaining months, from October through May, will be considered the winter season.

For purposes of determining on-peak and off-peak periods, the company reviewed the relative distribution of hourly market prices within the summer and winter seasons and identified the hours which were higher than average in each season. The company's findings are set forth in the table below.

Table 1. Distribution of Hourly Market Prices

Hour																								
																		Hours with higher than average prices						
Season	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Summer (Jun-Sep)																								
Winter (Oct-May)																								

Based on this analysis, on-peak hours in the summer are defined as 2:00 p.m. to 10:00 p.m. Pacific Prevailing Tim (PPT). On-peak hours in the winter are defined as 6:00 a.m. to 8:00 a.m. in the morning and 5:00 p.m. to 11:00 p.m. at night, again in PPT. The proposal does not differentiate between weekdays, weekends, and holidays. All hours other than on-peak hours are considered off-peak hours.

While the seasons and on-peak/off-peak definitions are the same for all resources, and the same underlying hourly market price forecast is used, the generation profiles of wind and solar resources produce different weighted average prices from baseload resources. For example, solar delivers in the afternoon portion of the summer on-peak period, which has lower prices than the evening hours of the on-peak period. Similarly, solar output in the winter season is lowest is January and December, which are also the winter months with the highest market prices. For that reason, PacifiCorp is proposing distinct avoided energy values for four resource types: baseload, wind, fixed tilt solar, and tracking solar.

In accordance with WAC 480-106-040(4)(d), the avoided energy cost for variable resources will be reduced by the applicable integration costs identified in the most recently acknowledged IRP. At present, the integration costs from the 2017 IRP apply to wind and solar resources.

<u>Capacity</u>

Market Proxy Avoided Capacity Cost

WAC 480-106-040(1)b(ii) specifies that, when the most recently acknowledged IRP identifies

[1] The months of June, July, August, and September represent 141 percent of the annual average price; the remaining months of the year represent 79 percent of the annual average price.

the need for capacity in the form of market purchases not yet executed, the fixed costs of a simple-cycle combustion turbine (SCCT) unit from the IRP must be used as the avoided capacity cost of the market purchases.

PacifiCorp's recent IRPs have allowed market purchases to count toward meeting planning requirements up to specified limits. Portfolios can include summer purchases in July, winter purchases in December, or annual purchases spanning all 12 months. Chapter 6 of the company's 2017 IRP states:

> Three [front office transaction] types were included for portfolio analysis in the 2017 IRP: an annual flat product, a [Heavy Load Hour] HLH July for summer, and a HLH December for winter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. The HLH transactions represent purchases received 16 hours per day, six days per week for July and December.[2]

The company's 2017 IRP preferred portfolio included both summer and winter purchases in all years, and no annual purchases. Consistent with the 2017 IRP, which identified limited market purchases for capacity, and in accordance with the rule, the company has included two months of SCCT fixed costs in avoided capacity costs prior to the next planned capacity addition.

Inclusion of a full twelve months of SCCT fixed costs in the avoided capacity costs would artificially inflate the company's avoided costs and would be inconsistent with the company's limited reliance on market purchases for capacity during specific time periods in the 2017 IRP. The impact of assuming twelve months of SCCT fixed costs is shown in Table 2 below.

Table 2. Comparison of SCCT Fixed Cost Assumptions

Combined Capacity and Energy Costs, CY2020 ($/MWh)

Resource Type	12-Mo SCCT	Proposed 2-Mo SCCT	Delta	Delta, %
Baseload	$41.27	$31.73	$9.54	+30%
Wind	$31.86	$28.90	$2.96	+10%
Fixed Tilt Solar	$47.98	$27.32	$20.67	+76%
Tracking Solar	$53.56	$28.59	$24.96	+87%

The December and July market transactions identified in the preferred portfolio of the 2017 IRP represent the least-cost, least-risk opportunity available to customers and the IRP models could have selected an SCCT for capacity instead of market purchases. Including twelve months of SCCT fixed costs as a proxy for the market price is not consistent with the determination made in the 2017 IRP and would result in a one-sided reflection of SCCT costs without a corresponding reflection of SCCT benefits. These benefits would include the ability of the SCCT to dispatch and hold reserves and have previously been estimated at approximately $50

[2] PacifiCorp 2017 IRP. Chapter 6 – Resource Options. Pg. 141.

per kilowatt-year[3], or approximately half of the SCCT fixed cost from the 2017 IRP. Both the inconsistency with the 2017 IRP and the absence of SCCT benefits are inconsistent with customer indifference. Therefore, the company recommends approval of its avoided cost calculation based on two months of market purchases for capacity, consistent with the 2017 IRP.

In the alternative, if the Commission finds that twelve months of SCCT fixed costs are appropriate, the company would recommend that those costs be adjusted to subtract the capitalized energy costs representing the energy dispatch and operating reserve benefits the SCCT proxy would provide. Such a determination by the Commission would require the company to revise its avoided cost calculation and should this become necessary, the company requests at least two weeks following a Commission decision to provide its revised avoided costs.

Planned Resource Avoided Capacity Cost

The adopted rules state that the avoided cost of capacity must be based on the next planned capacity addition identified in the most recently acknowledged IRP or the most recent proposals received pursuant to an RFP that was issued consistent with WAC 480-107-001 *et seq*. For the reasons below, the company seeks approval from the Commission to use its 2017 solar request for proposals (the 2017S RFP) as the basis for its avoided capacity cost.

The Commission acknowledged PacifiCorp's 2017 IRP on May 7, 2018. Because Washington retail rates are based on resources included in the West Control Area Inter-Jurisdictional Cost Allocation Methodology (WCA), and consistent with the company's previous use of the WCA to set avoided costs, PacifiCorp reviewed the 2017 preferred portfolio to identify the next planned capacity addition in the WCA. The first WCA resource addition is an 11 MW Yakima solar resource in 2028. The cost estimate for this resource in the 2017 IRP was developed in 2016. Solar resource cost inputs to the 2017 IRP were prepared in the summer of 2016 and solar resource costs have declined appreciably since that time. As a result, the 2017 IRP assumptions are no longer a reasonable representation of PacifiCorp's avoided costs.

PacifiCorp's 2017S RFP for solar resources was issued in November 2017 and resulted in initial bid responses in December 2017 and best and final bids in February 2018. As part of the 2017S RFP, PacifiCorp received and shortlisted a bid for a power purchase agreement (PPA) for a tracking solar resource located in Oregon with a start date at the end of 2020. While the current rules only allow cost estimates from RFPs that are consistent with WAC 480-107, these rules were not in effect at the time PacifiCorp's 2017S RFP was prepared and therefore the 2017S RFP did not address all of the requirements. Nonetheless, the Oregon tracking solar resource from the 2017S RFP results represent the most current cost estimates. PacifiCorp provided an update to the Commission on the 2017S RFP in November of 2017 in Docket UE-160353. PacifiCorp has kept the Commission apprised of RFP updates since that time.

[3] PacifiCorp 2019 IRP Public Input Meeting, Nov. 1, 2018. Slide 15. Available online at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-presentations-and-schedule/2018-11-011%20-%20General%20Public%20Meeting.pdf

Capitalized Energy Cost Adjustment
PacifiCorp's capacity additions provide both energy and capacity benefits. For instance, solar resources provide zero cost energy. Because avoided energy costs are already calculated based on market prices, it is appropriate to subtract capitalized energy costs when determining avoided capacity costs. Capitalized energy costs are calculated based on the capacity factor and generation profile of the planned capacity addition, relative to any variable resource costs and the same market prices used to set avoided energy costs. After the capitalized energy value is netted against the planned resource cost, any remainder represents the avoided cost of capacity.

The Oregon tracking solar resource from the 2017S RFP has a PPA price that is slightly higher than the forecast of market prices in this filing from 2021 through 2024, implying a small avoided capacity cost. Thereafter, the capitalized energy cost (*i.e.*, market value of the resource) exceeds the contract price, such that the avoided capacity cost associated with the 2017S RFP resource is zero.

Planned Resource Capacity Contribution Adjustment
The Oregon tracking solar resource from the 2017S RFP is located on the west side of the PacifiCorp system. Based on the capacity contribution analysis in the 2017 IRP, this type of resource has capacity contribution of 64.8%. The resource costs and capitalized energy costs described above are per kW of nameplate capacity for this resource. To get a more generic cost of capacity per kW of capacity contribution (*i.e.*, for a 100% capacity contribution resource), the results described above are grossed up by multiplying by the desired capacity contribution basis (100%) and dividing by the capacity contribution of the 2017S RFP resource (64.8%). For example:

2017S RFP Capacity Cost (in 2021) x 100% / 64.8% = \$3.1/kw-yr x 100% / 64.8% = \$4.9/kw-yr

Planned Resource Capacity Cost Levelization
WAC 480-106-040(c) specifies that schedules of estimated avoided costs must include levelization of the avoided cost of capacity to account for any difference between the in-service date of the qualifying facility and the date of the next planned generating unit. The proposed planned resource will be fully in-service during calendar year 2021. For purposes of the proposed tariff schedule, PacifiCorp proposes that the levelization reflect the net present value of the planned resource capacity costs over a 15-year term from 2020 through 2034. The resulting levelized value for 2020 is escalated at inflation through the end of the tariff period. The resulting levelized capacity costs associated with the 2017S RFP resource are negative.

Renewable Energy Credit Ownership

WAC 480-106-050(4)(b)(ii)(c) specifies that the utility receives the renewable energy certificates (RECs) during any period when standard rates are based on the avoided capacity costs of an eligible renewable resource. The Oregon tracking solar resource from the 2017S RFP is an eligible renewable resource, so the company will retain RECs generated by QFs starting in 2021.

Resource-Specific Avoided Capacity Costs by Season
The avoided market proxy capacity costs and avoided planned resource capacity costs both reflect a 100 percent capacity contribution. In accordance with 480-106-040 (2), these values are adjusted by resource-specific capacity contributions to determine the avoided capacity value for different Washington QF resource types. The assumed capacity contributions are based on the assumptions in the 2017 IRP Wind and Solar Capacity Contribution Study.[4]

- Baseload: 100%
- Wind: 11.8%
- Fixed Tilt Solar: 53.9%
- Tracking Solar: 64.8%

Prior to the online date of the first planned resource, avoided capacity costs based on a SCCT are spread between the summer and winter seasons based on the market purchase selections in the IRP. The 2017 IRP preferred portfolio includes one month of market purchases for capacity in the summer and one month of market purchases for capacity in the winter in each year of the study period, so half of the cost is included in the summer and half in the winter. For 2019, the summer peak will be over before rates take effect, so no avoided summer capacity is included.

Starting with the online date of the first planned resource, avoided capacity costs are spread between the summer and winter seasons based on the capacity contribution study from the 2017 IRP. In that study, approximately 99 percent of PacifiCorp's loss of load events occurred in the June through September timeframe, so 99 percent of the capacity value is assigned to the summer.[5] Summer and winter capacity costs are spread over each resource's expected generation during those periods, and are applied as a $/MWh adjustment to all hours of the season.

Combined Energy and Capacity Costs

Both energy and capacity costs have been presented as $/MWh values, as described above, so combined costs reflect the simple sum of the two components. Note that capacity costs are allocated to both on-peak and off-peak generation, by season. The proposed rates are generally lower than the current approved rates, which are not differentiated by season, on- and off-peak, or by resource type. These lower rates provide a more accurate reflection of PacifiCorp's avoided costs and better ensure customer indifference. A comparison of the current and proposed rates is set forth below in Table 3.

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[4] PacifiCorp 2017 Integrated Resource Plan. Volume II. Appendix N. Available online at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2017-irp/2017_IRP_VolumeII_2017_IRP_Final.pdf.
[5] *Ibid*. Figure N.2, pg. 317.

Table 3. Comparison of Avoided Costs

Comparison between Proposed and Current Standard Fixed Avoided Costs
Average Energy and Capacity Price at Expected Output

	$/MWh			$/MWh			$/MWh			$/MWh		
	Baseload			**Wind**			**Fixed Tilt Solar**			**Tracking Solar**		
Year	Proposed	Current	Delta	Proposed	Current	Delta	Proposed	Current	Delta	Proposed	Current	Delta
2019 (p)	$34.12	$27.08	$7.04	$32.84	$27.08	$5.76	$29.00	$27.08	$1.92	$30.71	$27.08	$3.63
2020	$31.73	$32.05	($0.32)	$28.90	$32.05	($3.15)	$27.32	$32.05	($4.73)	$28.59	$32.05	($3.46)
2021	$35.31	$32.89	$2.42	$33.85	$32.89	$0.96	$28.21	$32.89	($4.68)	$28.72	$32.89	($4.17)
2022	$34.51	$36.57	($2.06)	$32.85	$36.57	($3.72)	$28.05	$36.57	($8.52)	$29.55	$36.57	($7.02)
2023	$31.87	$40.40	($8.53)	$29.95	$40.40	($10.45)	$26.54	$40.40	($13.86)	$28.85	$40.40	($11.55)
2024	$32.77	$44.39	($11.62)	$30.54	$44.39	($13.85)	$28.00	$44.39	($16.39)	$30.75	$44.39	($13.64)
2025	$35.92	$47.26	($11.34)	$33.48	$47.26	($13.78)	$30.82	$47.26	($16.44)	$33.78	$47.26	($13.48)
2026	$38.11	$49.08	($10.97)	$35.73	$49.08	($13.35)	$32.54	$49.08	($16.54)	$35.72	$49.08	($13.36)
2027	$38.95	$49.32	($10.37)	$36.54	$49.32	($12.78)	$33.13	$49.32	($16.19)	$36.22	$49.32	($13.10)
2028	$40.97	$49.43	($8.46)	$38.46	$49.43	($10.97)	$34.88	$49.43	($14.55)	$38.20	$49.43	($11.23)
2029	$43.00	$50.57 (x)	($7.57)	$40.23	$50.57 (x)	($10.34)	$36.49	$50.57 (x)	($14.08)	$39.91	$50.57 (x)	($10.66)
2030	$44.53	$51.73 (x)	($7.20)	$41.61	$51.73 (x)	($10.12)	$37.90	$51.73 (x)	($13.83)	$41.45	$51.73 (x)	($10.28)
2031	$46.60	$52.92 (x)	($6.32)	$43.61	$52.92 (x)	($9.31)	$39.61	$52.92 (x)	($13.31)	$43.39	$52.92 (x)	($9.53)
2032	$48.64	$54.14 (x)	($5.50)	$45.75	$54.14 (x)	($8.39)	$41.28	$54.14 (x)	($12.86)	$45.15	$54.14 (x)	($8.99)
2033	$52.53	$55.33 (x)	($2.80)	$49.27	$55.33 (x)	($6.06)	$44.90	$55.33 (x)	($10.43)	$49.22	$55.33 (x)	($6.11)
2034	$55.04	$56.55 (x)	($1.51)	$51.55	$56.55 (x)	($5.00)	$47.33	$56.55 (x)	($9.22)	$52.18	$56.55 (x)	($4.37)
2035	$57.89	$57.79 (x)	$0.10	$53.83	$57.79 (x)	($3.96)	$50.28	$57.79 (x)	($7.51)	$55.48	$57.79 (x)	($2.31)
2036	$58.64	$59.06 (x)	($0.42)	$54.63	$59.06 (x)	($4.43)	$50.71	$59.06 (x)	($8.35)	$56.07	$59.06 (x)	($2.99)
2037	$66.19	$60.36 (x)	$5.83	$61.45	$60.36 (x)	$1.09	$58.65	$60.36 (x)	($1.71)	$65.51	$60.36 (x)	$5.15
2038	$69.57	$61.69 (x)	$7.88	$64.72	$61.69 (x)	$3.03	$61.56	$61.69 (x)	($0.13)	$68.63	$61.69 (x)	$6.94
2039	$71.69	$63.05 (x)	$8.64	$66.72	$63.05 (x)	$3.67	$63.31	$63.05 (x)	$0.26	$70.52	$63.05 (x)	$7.47

(p) Partial Year
(x) Extrapolated

15 Year Nominal Levelized Price ($/MWh) at 6.910% Discount Rate (2017 IRP Update)

(2020-2034)	$38.80	$44.70	($5.90)	$36.38	$44.70	($8.32)	$32.76	$44.70	($11.94)	$35.43	$44.70	($9.27)
(2021-2035)	$40.34	$46.60	($6.27)	$37.89	$46.60	($8.71)	$34.05	$46.60	($12.55)	$36.98	$46.60	($9.63)
(2022-2036)	$41.62	$48.60	($6.98)	$39.00	$48.60	($9.60)	$35.36	$48.60	($13.24)	$38.64	$48.60	($9.95)

Schedule Revisions-Non-Standard Rates

WAC 480-106-050(5)(a) indicates that the company's standard avoided costs should be the starting point for non-standard pricing. Therefore, the company is proposing to calculate its non-standard QF avoided costs using the same methodology and assumptions proposed for standard QF avoided costs (set forth in detail above), with the following modifications:

- Project-specific data, including:
    - Contract start and end dates,
    - Generation profile,
    - Location and delivery point.
- Updated Mid-C market price forecast – the company's most recent official forward price curve.
- Updated information from the most recently published IRP or IRP Update, including:
    - Resource cost and performance assumptions from the supply-side resource table
    - Capacity contribution assumptions
    - Integration costs
    - Preferred portfolio

- If available, the most recent resource cost and performance assumptions from an RFP.
- Changes in the timing of planned resource additions after accounting for the addition of newly signed contracts to the Company's portfolio.

At present, the proposed non-standard rate methodology would produce the same rate for a non-standard QF as a standard QF, as long as the generation profile was the same.

Standard PPA

WAC 480-106-030(4) requires the company to file "standard contract provisions for purchases from a [QF] with a capacity of five megawatts or less." In compliance with this requirement, the company has elected to file a complete form of contract template for standard QFs that will (in the company's experience) be responsive to the significant majority of all standard QF requests. The standard QF PPA filed applies to on-system, firm, greenfield QF projects that meet the definition of "small power production facility" under PURPA.[6] As circumstances require, the company will modify this form as appropriate for operating (*i.e.*, existing) QFs, off-system QFs,[7] cogeneration QFs, and QFs that request to provide output on an "as available" (*i.e.*, non-firm) basis. The form of PPA attached contains commercially reasonable terms consistent with the requirements of WAC 480-106-030(4).

In addition to the standard PPA, consistent with WAC 480-106-030(5), the company is creating a non-binding term sheet for non-standard PPAs that will be posted on the company's website. This term sheet will serve as the basis for PPA negotiations between the company and QFs.

Please contact Ariel Son at (503) 813-5410 if you have any questions.

Sincerely,

/s/

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[6] Consistent with WAC 480-106-030(5), a non-binding term sheet setting forth the key terms for a non-standard PPA will be published on the company's website.
[7] "Off-system," as used here, refers to a QF that interconnects to a third-party transmission system and proposes to secure firm transmission to deliver the output of the resource to a point of delivery on the company's transmission system in Washington.