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A DIVISION OF PACIFICORP

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November 18, 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 UE-190666—Pacific Power's Supplemental Filing

On August 9, 2019, Pacific Power & Light Company (Pacific Power), a division of PacifiCorp, submitted tariffs in compliance with the new requirements set forth in the revised rules in WAC 480-106. On October 21, 2019, Pacific Power, Washington Utilities and Transportation Commission (Commission) staff, and Renewable Energy Coalition / Northwest Intermountain Power Producers met for an informal discussion regarding the substantive issues in this docket and collaboratively outline next steps to resolve these issues. The parties agreed on the following process and schedule:

Date	**Item**
November 18, 2019	Pacific Power Supplemental Filing to provide clarifications, additional supporting evidence, and housekeeping changes
December 6, 2019	Stakeholder Comments
December 20, 2019	Pacific Power Responsive Comments
January 23, 2019	Open Meeting

Pacific Power appreciates the willingness of parties to collaborate with the company to reach a good outcome outside of a protracted litigated proceeding. Pacific Power would also like to thank Commission staff for their leadership in coordinating these efforts, and their attentive willingness to meaningfully engage in the company's and stakeholders' concerns. In accordance with the proposed process and schedule, Pacific Power submits this filing for the Commission and stakeholder's consideration.

Confidential workpapers are provided to the Commission in accordance with WAC 480-07-160.[1] The confidential workpapers include valuable commercial information, specifically confidential cost and financial information associated with loads and pricing. Disclosure of such information would harm Pacific Power by an unfair competitive disadvantage.

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[1] Due to the nature of the files it is impractical and unduly burdensome to provide a redacted version of these materials. Therefore, consistent with WAC 480-07-160(8) the company has not shaded and labeled the spreadsheets but has clearly labeled them as 'Confidential' to identify these materials.

Clarifications

In response to feedback with parties, the company proposes to clarify two items in its proposed Schedule QF.

First, the company's proposed non-standard avoided cost methodology was described in its cover letter, but was not referenced in the proposed schedule. Therefore, on page QF.6 of proposed Schedule QF, at the end of section I.B.3. of the "Contracting Procedures for Non-Standard QFs," the company proposes to add the following:

> *The methodology for non-standard avoided cost pricing is the same as that used to develop standard rates, but incorporates project-specific data, as well as inputs from the company's most recent official forward market prices, IRP or IRP Update filing, request for proposal results, and signed contracts.*

Second, the company's proposed schedule does not reference the five-year contract term limit for Qualifying Facilities (QFs) that do not meet specified greenhouse gas emissions standards in accordance with WAC 480-106-050(4)(a)(iii). Therefore, within subsection (i) of Table 1 and Table 2 of proposed Schedule QF, the company proposes to add the following:

> *RCW 80.80.040-Non-Compliant QFs – less than five years from first-delivery date.*

Supporting Information

During the ongoing dialogue related to the company's filing, parties have expressed concerns about the company's interpretation of the rules and the assumptions used to develop the avoided cost prices contained in its compliance filing. In particular, Commission staff requested additional supporting information related to three topics:

1. Peaker proxy methodology
2. Front office transaction resource selection
3. West Control Area Inter-Jurisdictional Allocation Methodology (WCA) view of capacity contribution and load and resource balance

The company's proposed rates represent avoided cost prices that are reasonably aligned with the costs it would otherwise incur to serve customers, and therefore more in line with the Public Utility Regulatory Policies Act (PURPA) mandate, supported by the Federal Energy Regulatory Commission (FERC), that a utility's customers be indifferent to QF and non-QF sources of power. To the extent modifications to rates are proposed that vary significantly from the company's filing, the company respectfully requests that the Commission consider whether evidence supports the conclusion that proposed rates result in customer indifference relative to alternative sources of power. To the extent rules must be waived or modified in accordance with WAC 480-106-003 to ensure customer indifference, the company also requests that the Commission consider those changes.

Regardless of the Commission's determinations on specific avoided cost inputs, the Commission should find that the resulting avoided cost methodologies and the resulting prices do not set costs at a level that will cause customers to incur unnecessary costs.

Peaker Proxy Methodology

WAC 480-106-040(1)(b)(ii) specifies that, when the most recently acknowledged integrated resource plan (IRP) identifies 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. The company's filing incorporated the costs of two months of SCCT fixed costs, based on the types of market capacity resources selected in PacifiCorp's acknowledged 2017 IRP. Commission staff expressed concern about whether twelve months of SCCT fixed costs would be more in line with the rule.

SCCT Dispatch Benefits (Capitalized Energy Costs)

In its initial filing, the company expressed that it is inappropriate to base QF pricing on SCCT fixed costs without accounting for the benefits that an SCCT would provide if it was under the company's control. Also in its initial filing, the company described the calculation of capitalized energy costs for the solar resources used to derive planned resource capacity costs. An analogous calculation can be used to estimate the energy benefits associated with the SCCT proxy used to establish the peaker proxy adjustment. For each hour, the variable costs of the SCCT proxy are compared against the market prices used to establish the energy costs for QF pricing. The margin between the market price and SCCT variable costs by year is shown in Table 1 below, along with related assumptions.

In addition, the proxy SCCT unit from the 2017 IRP[2] used in the avoided cost methodology has quick start capability that allows it to provide operating reserves when called upon at short notice. The company must maintain a supply of flexible resources at all times to cover uncertainty in load and the output of variable energy resources, such as wind and solar. Because these operating reserves are only called upon when needed, resources with the highest variable costs are designated to provide operating reserves. When the SCCT provides operating reserves, the lower cost resources, on which reserves would otherwise have been held absent the SCCT, are freed up to generate if they are economic relative to market. The value that is attributable to the SCCT is the margin, or the difference between the generation costs and the market value, associated with the freed up generation. For the purposes of this analysis, the company calculated the value of the SCCT using the average heat rate of its Chehalis and Hermiston gas plants in 2018, with the estimated benefits shown in Table 1.

Finally, hourly market prices do not account for the benefits of dispatching an SCCT on an intra-hour basis as is done in the energy imbalance market. As part of the analysis for the 2019 IRP,

[2] The unit used as a proxy is the SCCT Frame "F" x1, 1500' elevation shown in Tables 6.1 and 6.2 of the 2017 IRP.

the company estimated that the intra-hour benefits of the Frame F SCCT were approximately $3,470/MW-year (2018$).[3]

Table 1: Simple Cycle Combustion Turbine Capitalized Energy Costs

	Burnertip Gas Price	Total Capacity Cost @ 100% Contribution	Energy Margin	OpRsv Margin	Intra-hour Margin	Net Capacity Cost	Capitalized Energy Cost vs Fixed Cost
Year	$/MMBTU	$/MW-yr	$/MW-yr	$/MW-yr	$/MW-yr	$/MW-yr	%
2020	2.11	$100,327	($54,825)	($53,200)	($3,630)	($11,328)	108%
2021	2.11	$102,534	($91,606)	($59,729)	($3,713)	($52,514)	148%
2022	2.23	$104,892	($77,368)	($58,445)	($3,797)	($34,718)	129%
2023	2.47	$107,200	($56,187)	($46,144)	($3,884)	$985	95%
2024	2.81	$109,558	($52,613)	($43,102)	($3,973)	$9,870	87%
2025	3.15	$111,969	($59,078)	($44,961)	($4,063)	$3,867	93%
2026	3.40	$114,432	($59,762)	($47,346)	($4,156)	$3,168	94%
2027	3.56	$116,950	($58,098)	($48,171)	($4,251)	$6,430	91%
2028	3.81	$119,639	($59,939)	($49,556)	($4,347)	$5,797	92%
2029	3.97	$122,391	($65,942)	($51,130)	($4,447)	$872	96%
2030	4.11	$125,206	($68,742)	($53,438)	($4,548)	($1,522)	98%
2031	4.39	$128,086	($68,750)	($55,175)	($4,652)	($491)	97%
2032	4.62	$131,032	($70,079)	($57,319)	($4,758)	($1,125)	97%
2033	4.96	$133,914	($80,151)	($61,556)	($4,866)	($12,659)	106%
2034	5.09	$136,861	($90,328)	($63,600)	($4,977)	($22,045)	112%
2035	5.19	$139,872	($105,745)	($65,549)	($5,091)	($36,513)	122%
2036	5.27	$142,949	($104,320)	($68,537)	($5,207)	($35,115)	121%
2037	5.68	$146,094	($137,196)	($74,483)	($5,325)	($70,910)	145%
2038	5.92	$149,308	($145,758)	($78,064)	($5,447)	($79,961)	150%
2039	6.15	$152,592	($147,100)	($81,130)	($5,571)	($81,208)	150%

2017 IRP - SCCT Frame "F"x1 - West Side Options (1500')

Heat Rate	9.604	MMBTU/MWh
VOM	5.81	2016$/MWh
Source	2017 IRP Table 6.2	
Gas Price	June 2019 OFPC	

Note that the calculations set forth in Table 1 are not a comprehensive representation of all of the benefits associated with an SCCT, which can provide additional benefits as a result of its ability

[3] PacifiCorp 2019 Integrated Resource Plan. Volume II, Appendix Q. Table Q.2. Available online at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_M-R.pdf

to be economically dispatched. For instance, the hourly market prices do not fully represent the expected variability in prices within a month, as it has an identical twenty-four hour shape on each weekday in a month. In reality, prices will vary above and below the average, and an SCCT could be kept offline whenever market purchases could be procured at a lower cost. To keep the average price the same, prices would necessarily be higher in the remainder of the month, resulting in an overall higher margin. In the company's IRP modeling, stochastic variations in market prices would help capture this effect. This effect would not be significant for resources whose output does not correspond with market price changes.

In addition, market prices may not fully represent the company's marginal resource costs. The company does not generally assume an unlimited ability to either buy or sell in the market and transmission congestion may prevent otherwise economic resources from reaching a market point. As a result, the value of a resource could be either higher or lower than market depending on the company's load and resource mix. These factors also impact the value of operating reserves. In practice, operating reserves for the WCA have traditionally been held on hydro and thermal resources. In the future, operating reserves may also be held on energy storage resources or load control programs. Because energy limited resources like hydro, energy storage, and load control have limited ability to generate, freeing up these resources from holding operating reserves can have limited benefits. As a result, production cost modeling with a portfolio that reflects expected future conditions produces the most accurate estimate of all of these components. This is the type of analysis performed in the company's IRP.

Front Office Transactions

The company's 2017 IRP and 2019 IRP both assume that front office transactions (FOTs) may be used to meet capacity planning requirements. FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the company cover short positions. Both IRPs assume that the cost of FOTs is equal to the forecasted market price, plus a $1-2/MWh adder. Both IRPs also assume that the term for FOTs is a heavy-load hour (HLH) product for the month of July, a HLH product for the month of December, or a flat product for all hours of the year. In the 2017 IRP, both July and December products were identified as capacity resources in all years as part of the least-cost, least-risk preferred portfolio. The 2019 IRP identifies primarily July and December products, but also includes flat products starting in 2029. While these discrete products are defined for the purposes of capacity planning, the company's actual operations and modeled system dispatch include market purchases throughout the year. In the 2019 IRP, purchases are restricted to the FOT limits in the peak summer and winter months, and are restricted based on transmission limits in other months.

In actual operations, the company can procure resources in a variety of ways on a short to intermediate term basis. In addition to traditional heavy-load, light-load, and all-hour market products, the company can transact for market products that are more specific to its requirements than the 16-hour HLH block. The company can also procure rights to specific resources, for instance hydro and gas facilities, which can be dispatched in a manner comparable to the owned assets in its portfolio. For instance, in 2017 the company entered a one-year tolling agreement for the output of a 185 MW SCCT plant in Utah. The fixed cost of this contract was well below the assumed cost of a new proxy SCCT.

While the company pursues a variety of short-term products, and acquires various types based on need and economics, a significant portion of its market requirements are acquired on a day-ahead basis (on the trading day prior to the day of delivery). This has been the company's practice for many years. Given its reliance on market, the company's market price forecast is designed to realistically reflect market clearing prices. One way to express market prices while accounting for differences in gas price forecasts is to calculate an implied heat rate. Dividing the forecasted electricity price ($/MWh) by the forecasted gas price ($/MMBTU) produces an estimate of the heat rate of the marginal resource (MMBTU/MWh). The monthly implied heat rate of HLH transactions at Mid-Columbia from both the company's 2018 actual day-ahead transactions and its official forward price curve is shown in Table 2.

Table 2: Market Implied Heat Rate: Mid-Columbia HLH vs Burnertip West Gas

	Month											
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
2018	8.17	10.70	10.67	8.92	8.51	9.34	31.78	34.92	12.52	10.01	6.74	10.81
2019										15.60	12.44	14.58
2020	14.36	13.03	11.48	12.37	11.94	11.54	23.74	30.75	19.14	16.07	14.17	14.72
2021	18.21	16.37	15.14	14.80	14.29	14.15	27.99	30.95	27.74	19.13	16.97	18.03
2022	17.10	15.12	13.70	17.14	16.73	16.75	29.88	30.92	19.53	15.22	13.46	13.54
2023	13.21	12.66	11.69	12.58	11.44	15.49	27.83	30.90	12.67	11.94	10.39	9.64
2024	9.67	10.31	9.85	9.39	7.89	14.61	26.41	29.53	12.36	11.29	9.57	9.43
2025	9.27	9.69	9.41	9.08	7.52	14.25	25.35	31.38	12.16	10.88	9.57	9.45
2026	9.35	9.75	9.38	9.30	7.26	14.85	25.57	27.82	11.66	10.62	9.62	9.33
2027	9.10	9.53	9.11	8.77	6.81	15.02	23.99	27.13	11.52	10.74	9.45	9.27
2028	9.10	9.50	8.88	8.39	6.70	15.05	24.14	26.02	10.90	10.26	9.41	9.27
2029	9.14	9.31	8.82	8.76	6.35	12.98	23.93	28.70	11.20	10.31	9.37	9.28
2030	9.32	9.54	8.76	8.26	5.99	13.50	24.41	27.56	11.18	10.56	9.18	9.39
2031	9.20	9.39	8.40	7.98	5.71	13.96	23.81	25.69	10.91	10.19	9.23	9.47
2032	9.25	9.45	8.54	8.46	5.45	14.58	23.05	24.75	10.66	9.97	9.30	9.40
2033	9.09	9.36	8.16	7.52	5.40	14.99	24.08	25.85	10.63	10.36	9.32	9.38
2034	9.12	9.31	8.21	7.73	5.64	15.78	26.18	26.50	10.49	10.06	9.36	9.47
2035	9.22	9.32	8.36	8.49	5.51	13.42	25.79	33.28	10.93	10.33	9.23	9.37
2036	9.31	9.38	8.38	7.86	5.38	14.28	27.99	29.49	10.99	10.63	9.20	9.48
2037	9.39	9.51	8.51	8.03	5.40	15.58	31.20	33.93	11.11	10.31	9.43	9.62
2038	9.41	9.52	8.62	8.65	5.52	16.20	30.07	34.52	11.08	10.33	9.58	9.69

Table 2 illustrates how the proxy SCCT, with what is traditionally thought of as a high heat rate, of 9.604 MMBTU/MWh can provide the significant energy and dispatch benefits shown in Table 1. In the west-wide peak months of July and August, the implied market heat rate is well above an SCCT. Note that the proxy SCCT unit can provide benefits even in months where the HLH implied heat rate shown in Table 2 is less than its heat rate. This is a result of variations in hourly prices, which only need to exceed the proxy SCCT heat rate for a couple of hours in a row to justify operation of the unit and create a margin, whereas the 16-hour average of the HLH block may reflects many hours that are not economic. This spread of prices across the day was the basis for the company's proposed on-peak and off-peak pricing definitions. The company's official forward price curve reflects market quotes in the first three years, through 2022, and a fundamentals-based forecast starting in 2024, with a one-year transition in between. The fundamentals portion of the electricity OFPC reflects prices forecasted using AURORA[4]$_{XMP}$ (Aurora), a WECC-wide market model. The transition to the fundamentals portion of the curve is driving at least part of the drop in heat rates in 2024. The WECC-wide model also includes current utility regulations, for instance increases in RPS obligations in California and other states. Increases in wind and solar generation from resources brought online before the end of 2023 would also contribute to lower implied heat rates, as zero-variable cost renewable resources would tend to drive down marginal costs. Despite having high price in a portion of the year, neither the 2017 IRP nor the 2019 IRP indicate that adding resources to avoid market purchases is necessary to achieve least-cost, least-risk outcomes in the next several years.

Adding twelve months of SCCT fixed costs to the HLH market prices in the company's official forward price curve results in significantly higher avoided costs. For example, the fixed cost of the proxy SCCT is approximately $100,000/MW-yr in 2020. This equates to an additional $20.36/MWh when spread across the 4,928 HLH hours in 2020. Table 3 illustrates the effective implied heat rate during HLH hours when SCCT Fixed Costs are added. Over the first ten years, the proxy SCCT costs represent an increase of more than 50%.

Table 3: Market Implied Heat Rate with SCCT Fixed Cost

Year	OFPC	SCCT Fixed Cost	Total	% Increase
2018	13.59	n/a		
2019	14.21	8.04	22.25	57%
2020	16.11	9.65	25.76	60%
2021	19.48	9.88	29.36	51%
2022	18.26	9.59	27.85	53%
2023	15.04	8.87	23.90	59%
2024	13.36	7.90	21.26	59%
2025	13.17	7.24	20.41	55%
2026	12.88	6.84	19.72	53%
2027	12.54	6.69	19.22	53%
2028	12.30	6.39	18.69	52%
2029	12.34	6.27	18.62	51%
2030	12.31	6.21	18.51	50%
2031	12.00	5.94	17.93	49%
2032	11.91	5.76	17.66	48%
2033	12.01	5.50	17.51	46%
2034	12.32	5.49	17.81	45%
2035	12.77	5.48	18.25	43%
2036	12.70	5.50	18.20	43%
2037	13.50	5.24	18.74	39%
2038	13.60	5.14	18.74	38%

[4] AURORA$_{XMP}$ is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

There is no evidence that the company's historical market purchases have included costs equivalent to the 12 months of proxy SCCT fixed costs required based on staff's interpretation of the recently adopted rules. Similarly, there is no evidence that adding those fixed costs to the company's official forward price curve results in a more accurate estimate of the cost customers would otherwise incur. Moreover, the least-cost, least-risk portfolio from the company's acknowledged 2017 IRP does not assume that these costs would be incurred. To the extent the Commission deems the inclusion of proxy SCCT fixed costs appropriate to more accurately represent the cost and risk of market purchases, it would be appropriate to include those assumptions with the company's IRP modeling. Faced with an appreciable increase in the cost of market purchases, the IRP models would be expected to increase selections of alternative resource options, including energy efficiency and SCCTs, while reducing market reliance.

WCA Capacity Contribution

The company has not prepared a WCA-specific analysis of the capacity contribution of specific resources, as its analysis has been focused on its system-wide portfolio and requirements. Nonetheless, in the 2017 IRP capacity contribution analysis, less than 1% of all loss of load events used to derive the capacity contribution of wind and solar were in the winter months of October through May. While a sense of the winter peaking requirements can be inferred from those winter loss of load events that are present, the small sample size limits the confidence in the results. For instance, two-thirds of the "winter" events are during the April and October planned outage windows when load is limited and many opportunities for alternative supply are available.

Since the capacity contribution values reported in the 2017 IRP were prepared, the penetration of solar resources in PacifiCorp's portfolio has increased significantly. As a result, the risk of loss of load events has dropped during the day, and the capacity contribution of solar resources has declined. With that in mind, more detailed consideration of the 2017 IRP analysis does not provide results that are consistent with current expectations.

In its recently filed 2019 IRP, the company made a more concerted effort to analyze winter requirements, including the calculation of distinct winter and summer capacity contributions for each resource. Based on the retirements and assumptions consistent with the 2019 IRP preferred portfolio, approximately 8% of loss of load events would occur in the winter, which provides a reasonable sample from which to assess winter requirements. The capacity contributions of resource options in Washington from the 2019 IRP are shown in Table 4 below.[5]

[5] PacifiCorp 2019 Integrated Resource Plan. Volume II, Appendix N: Capacity Contribution Study. Tables N.4-N.5.

Table 4: 2019 IRP Capacity Contribution Results

Resource	Capacity Factor (%)	Capacity Contribution (%)	
	Annual	Summer	Winter
Tracking Solar - Yakima, WA	25%	12%	10%
Tracking Solar and 25% Storage - Yakima, WA	25%	33%	34%
Wind - Goldendale, WA	37%	57%	21%
Wind and 25% Storage - Goldendale, WA	37%	76%	44%
Lithium Ion 2 hour duration		78%	89%
Lithium Ion 4 hour duration		94%	100%

The capacity contribution values shown are dependent on the composition of the company's portfolio. The contribution of solar resources would be lower, particularly in the winter, if not for the significant energy storage resources present in the 2019 IRP preferred portfolio. The capacity contribution of storage would be lower in the absence of the wind and solar resources in the 2019 IRP preferred portfolio. Since the 2017 IRP, the capacity contribution of solar in Washington has declined significantly from 64.8%, while the contribution of wind in Washington has increased significantly from 11.8%. In addition, these capacity contribution values are applicable to incremental changes relative to the 2019 IRP preferred portfolio. As wind and solar penetration increases in a portfolio, the capacity contribution tends to decline, as resource additions will tend to have output that is correlated with resources already in the portfolio that will reduce the likelihood of loss of load events during periods when the resource additions are likely to be available. With this in mind, the company's 2019 IRP also evaluated the effective contribution of the wind and solar resources in its preferred portfolio over time.[6]

The 2019 IRP identifies annual capacity balances of the company's existing and committed resources during the summer and winter peaks, using a target planning reserve margin of 13 percent.[7] The values reported in the 2019 IRP are shown for the east and west control areas, but reflect system planning and dispatch. Certain adjustments are required to identify capacity positions consistent with the WCA, as shown in Tables 5 and 6 for summer and winter peaks, respectively.

[6] PacifiCorp 2019 Integrated Resource Plan. Volume I, Chapter 5. Figures 5.3-5.4.
[7] PacifiCorp 2019 Integrated Resource Plan. Volume I, Chapter 5. Tables 5.12-5.13.

Table 5: 2019 IRP Summer Peak West Capacity - Existing Loads and Resources

Calendar Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
West Existing Resources	3,187	3,227	3,126	3,078	3,074	2,792	2,802	2,805	2,771	2,604	2,227
Less Colstrip 3	(68)	(68)	(68)	(68)	(68)	(68)	(68)	(68)	(68)	-	-
Less Oregon/California QFs	(383)	(387)	(292)	(285)	(278)	(278)	(279)	(278)	(246)	(243)	(231)
West obligation	3,262	3,285	3,310	3,325	3,324	3,301	3,323	3,321	3,321	3,323	3,321
Planning Reserves (13%)	424	427	430	432	432	429	432	432	432	432	432
WA WCA Position	(951)	(940)	(974)	(1,032)	(1,029)	(1,284)	(1,300)	(1,294)	(1,296)	(1,394)	(1,757)
Available Front Office Transactions	1,159	1,159	1,159	1,159	1,159	1,159	1,159	1,159	1,159	1,159	1,159
East to West Transfer Capability	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Jim Bridger Availability	1,286	1,286	1,286	1,286	1,286	974	974	974	974	974	642
Potential East to West Transfers	314	314	314	314	314	626	626	626	626	626	958
Position with transfers	(637)	(626)	(660)	(718)	(715)	(658)	(674)	(669)	(671)	(768)	(799)

Table 6: 2019 IRP Winter Peak West Capacity - Existing Loads and Resources

Calendar Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
West Existing Resources	3,368	3,369	3,008	2,921	2,913	2,527	2,527	2,525	2,499	2,360	2,018
Less Colstrip 3	(68)	(68)	(68)	(68)	(68)	(68)	(68)	(68)	(68)	-	-
Less Oregon/California QFs	(141)	(142)	(102)	(93)	(88)	(75)	(75)	(72)	(45)	(45)	(33)
West obligation	3,324	3,327	3,340	3,350	3,347	3,335	3,331	3,329	3,335	3,340	3,347
Planning Reserves (13%)	432	432	434	435	435	434	433	433	434	434	435
WA WCA Position	(597)	(600)	(937)	(1,025)	(1,025)	(1,384)	(1,380)	(1,377)	(1,384)	(1,459)	(1,798)
Available Front Office Transactions	1,159	1,159	1,159	1,159	1,159	1,159	1,159	1,159	1,159	1,159	1,159
East to West Transfer Capability	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Jim Bridger Availability	1,286	1,286	1,286	1,286	1,286	974	974	974	974	974	642
Potential East to West Transfers	314	314	314	314	314	626	626	626	626	626	958
Position with transfers	(283)	(286)	(623)	(711)	(711)	(759)	(754)	(751)	(758)	(833)	(840)

The 2019 IRP analysis indicates that available FOTs are sufficient to meet Washington's view of WCA capacity in both the summer and winter through 2024. Available transfer capability can allow east-side resources to reach the west, such that capacity can be evaluated on a system basis. The 2019 IRP indicates that available FOTs are sufficient to meet system summer requirements through 2028 and winter requirements through 2029.[8]

While the 2019 IRP indicates that the existing resource portfolio and available FOTs could be sufficient until 2028, a number of resources are added prior to that date, indicating that their costs over the study period are lower than other resource alternatives. Resources added prior to 2028 include wind and solar resources brought online before 2024 that capture expiring production tax credits and investment tax credits, as well as energy efficiency and load control programs.

[8] *Ibid.*

Please direct questions to Ariel Son, Regulatory Affairs Manager, at (503) 813-5410.

Sincerely,

/s/

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Enclosures