PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 12, 2019

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: UM 2001—Interim Adjustments to Standard Avoided Cost Pricing

PacifiCorp d/b/a Pacific Power (PacifiCorp) provides interim updates to its standard avoided cost schedule (Schedule 37) in compliance with the Public Utility Commission of Oregon's (Commission) Order No. 19-074, which was issued on March 5, 2019. PacifiCorp also provides proposed Schedule 37 updates that include the additional enhancements it proposed in both its February 12, 2019, and February 25, 2019 comments so that Commission Staff, other stakeholders, and the Commission may consider accepting PacifiCorp's interim adjustments with these additional enhancements.

I. BACKGROUND

At the February 14, 2019 public meeting, the Commission opened a proceeding to engage in a comprehensive investigation of Oregon's implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA), docket UM 2000. In that same public meeting, the Commission also opened a proceeding under docket UM 2001 to allow it to consider whether to order interim PURPA implementation relief measures based on Commission Staff's February 7, 2019 report (Staff Report), and the responsive comments from interested parties. During the February 14, 2019 public meeting, the Commission requested that Staff issue a subsequent recommendation regarding the form of interim relief the Commission should adopt.

On February 21, 2019, Commission Staff issued its recommendation (Staff Recommendation) in part supporting enhanced updates to the utilities' avoided cost pricing. On February 25, 2019, PacifiCorp and other stakeholders filed comments to the Staff Recommendation. On February 26, 2019, at the Commission's public meeting, the Commission considered the comments of the parties and whether to adopt the Staff Recommendation. On March 5, 2019, the Commission issued Order No. 19-074 adopting Staff's recommendations, and requiring utilities to file their standard avoided cost schedules incorporating Staff's proposed enhancements. The new avoided cost schedules result in rates that are both higher than market prices for similar resources and renewable standard rates that are lower than non-renewable standard rates. These illogical outcomes and PacifiCorp's proposed solution are discussed more fully below.

II. DISCUSSION

A. PacifiCorp's Avoided Cost Pricing Must Conform with the Customer Indifference Standard

Avoided cost pricing approved by the Commission must conform with the standard that ensures retail customers remain indifferent to the company's purchase of qualifying facility (QF) power. Prices paid to QFs may not exceed "the incremental cost to the electric utility of alternative electric energy."[1] The incremental cost to a utility means the amount it would cost the utility to generate or purchase the electricity but-for the purchase from the QF.[2] The incremental cost standard is intended to leave customers 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 have otherwise incurred without the QF purchase.[3] The Commission has repeatedly acknowledged the importance of the customer indifference standard[4] and has identified the customer indifference standard as its "primary aim."[5]

B. PacifiCorp's Proposed Additional Enhancements to Schedule 37 Prices

In its February 12, 2019 comments, PacifiCorp proposed several specific additional enhancements beyond those included in the Staff Recommendation. Each of PacifiCorp's proposed additional enhancements would yield more accurate Schedule 37 prices than would updated prices that only incorporate the enhancements included in the Staff Recommendation. More accurate pricing is consistent with and required by the customer indifference standard. For this reason the company offers both Schedule 37 prices that include only the enhancements in the Staff Recommendation,[6] and Schedule 37 prices that include PacifiCorp's proposed additional enhancements.[7] Each additional enhancement is briefly described below.

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[1] 16 U.S.C. § 824a-3.
[2] *Id.* at § 824a-3(d).
[3] *Indep. Energy Producers Ass'n, Inc. v. Ca. Pub. Util. Comm'n*, 36 F.3d 848, 858 (9th Cir. 1994) ("If purchase rates are set at the utility's avoided cost, consumers are not forced to subsidize QFs because they are paying the same amount they would have paid if the utility had generated energy itself or purchased energy elsewhere.")
[4] *See, e.g.,* Docket No. UM 1129, Order No. 05-584 at 11 (May 13, 2005) ("We seek to provide maximum incentives for the development of QFs of all sizes, while ensuring that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs."); Docket No. UM 1129, Order No. 06-538 at 37 ("[O]ur overriding goals in this docket are to encourage QF development, while ensuring that ratepayers are indifferent to QF power."); Docket No. UM 1129, Order No. 07-360 at 1 (Aug. 20, 2007) ("This Commission's goal is to encourage the economically efficient development of QFs, while protecting ratepayers by ensuring that utilities incur costs no greater than they would have incurred in lieu of purchasing QF power (avoided costs)"); Order No. 14-058 at 12 ("We first return to the goal of this docket: to ensure that our PURPA policies continue to promote QF development while ensuring that utilities pay no more than avoided costs."); Docket No. UM 1734, Order No. 15-241 at 3 (Aug. 14, 2015) (The Commission must "protect ratepayers from the possibility of being charged more than PacifiCorp's avoided power costs….")
[5] *See, e.g.*, Order No. 05-584 at 45 ("In balancing the goals of facilitating QF contracts while sufficiently protecting ratepayers, we recognize that the primary aim is to ensure that ratepayers remain indifferent to the source of power that serves them.")
[6] *See*, PacifiCorp OR Schedule 37 Filing, Attachments 7, 10 & 12.
[7] *See*, PacifiCorp OR Schedule 37 Filing, Attachments 9, 11 & 13.

1. Solar and Wind Resource Costs

Solar resource costs in PacifiCorp's 2019 IRP are well below even the "updated" values based on the Staff Recommendation. It is a fundamental tenet of PURPA that customers should not pay more than the cost of comparable resources a utility could otherwise acquire. After accounting for forecasted cost declines, PacifiCorp's 2019 IRP assumes costs for a solar resource coming online in 2021 of $25.50/MWh for a Utah resource, and $28.94/MWh for an Oregon resource.[8] A reasonable interim rate would be to use the average of these solar resource costs for standard renewable solar prices. Since a solar resource cost is being used, no capacity adder is necessary starting in 2021 because a QF and the solar resource would have comparable capacity contributions.[9]

In a similar manner, PacifiCorp's 2019 IRP assumes costs for a wind resource coming online in 2021 of $15.59/MWh for a Wyoming resource, and $31.82/MWh for an Oregon resource. At this cost, Wyoming wind resources produce significant customer benefits, indicating they are less than avoided costs, which costs produce customer indifference rather than customer benefits. This is a flaw in the current avoided cost methodology. It is less clear whether the Oregon wind resource would produce customer benefits. Similar to PacifiCorp's proposal for solar, a reasonable interim rate would be to use the average of the wind resource costs identified above for standard renewable wind prices. PacifiCorp notes that this is an increase from Staff's proposal.

2. Disparities Between Non-Renewable Prices and Renewable Prices

Schedule 37 eligible QFs currently have the option to elect to receive either renewable pricing, in which case they are obligated to also provide renewable energy certificates in deficiency periods, or non-renewable prices where there is never an obligation to provide renewable energy certificates. However, the Staff Recommendation fails to correct the disparity between renewable and non-renewable Schedule 37 prices for QFs, where the current non-renewable price exceeds the renewable price. In PacifiCorp's resource value of solar docket (UM 1910) and other recent proceedings, PacifiCorp has demonstrated how this disparity runs contrary to the customer indifference standard and basic economics. If it is not corrected, then QFs will be able to take the higher non-renewable price, and keep the additional value of the renewable energy certificates (RECs) generated by the QF. In other words, customers will end up paying more to receive less value.

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[8] See the supply-side table for cost inputs and slide 7 from the Oct. 9, 2018 public input meeting for details on the capital de-escalation rates assumed in the 2019 IRP: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_October_9_2018_Public_Input_Meeting.pdf.

[9] In the absence of additional information, identical prices for fixed and tracking solar are reasonable on an interim basis, as these values have been only slightly different in the past. Levelized results vary slightly due to differences in resource profiles.

Under Staff's proposal, every single renewable rate is less than the analogous non-renewable rate. In addition, RECs generated by renewable portfolio standard (RPS) eligible resources in a given year are inter-changeable, so the difference between renewable and non-renewable rates should be identical for all resource types. To correct the disparity in the interim, as broader changes are considered in UM 2000 docket, PacifiCorp recommends that an enhancement to interim avoided cost pricing be adopted consistent with Commission Order No. 19-021 in docket UM 1910, which directed the use of the value from PacifiCorp's most recent RPS Compliance Cost filing. The July 12, 2018 filing had a compliance value of $1.92/MWh (2017$). Specifically, non-renewable prices should be equal to renewable prices, less the RPS compliance value.

The resource cost-based rates for wind and solar from the 2019 IRP described above produce renewable prices, as PacifiCorp's IRP generally assumes that it retains the RECs associated with proxy renewable resource additions. Therefore it is appropriate to calculate non-renewable prices by subtracting the RPS compliance cost from these renewable prices. For a baseload resource, Staff's proposed changes result in non-renewable prices that are higher than renewable prices, similar to the dichotomy in the current prices for wind. PacifiCorp proposes correcting the baseload renewable price by adding the RPS compliance cost to the non-renewable baseload price. The non-renewable price is a better starting point for baseload pricing, given PacifiCorp's recent resource acquisitions described above, which call into question the continued appropriateness of the capacity adder. PacifiCorp notes that its proposed renewable baseload pricing is an increase from Staff's proposal.

If the Commission declines to adopt non-renewable prices equal to renewable prices, less the RPS compliance value, PacifiCorp requests the Commission restrict all QFs to receiving only renewable avoided cost prices. Allowing QFs to choose a higher non-renewable rates and retain RECs violates the customer indifference standard and poses tangible harm to customers who ultimately bear the higher costs of QF power purchase agreements.

3. <u>Changes to payment factors, discount rates, resource-specific cost de-escalation for renewable resources, and inflation.</u>

The Staff Recommendation only allows for changes to payment factors, discount rates, resource-specific cost de-escalation for renewable resources, and inflation, "which are a direct result of the updated tax laws."[10] Only including those changes that "directly result" from the updated tax laws fails to incorporate all of the known data that impact the accuracy of the costs PacifiCorp's customers would incur for proxy resources. PacifiCorp has already published the relevant updated data as part of its 2019 IRP update.[11] The 2019 IRP has gone through its extensive public input process, and these inputs are not controversial. PacifiCorp requests that these updated inputs be included in the final enhanced avoided costs approved by the Commission. PacifiCorp would also note that each of the prior Schedule 37 updates have

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[10] Staff Recommendation at p. 5.

[11] PacifiCorp's June 28-29 IRP Public Input Meeting, see slides 69 and 74. Available online at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_PIM_June_28-29_2018_PUBLIC.pdf

included inflation forecasts consistent with the forward market prices in the filing. For instance, PacifiCorp's last limited annual update filing on May 1, 2017 reflected inflation from March 2017, not the 2015 IRP which was the most recently acknowledged at that time. Furthermore, the rates currently in effect following acknowledgment of PacifiCorp's 2017 IRP reflect inflation from March 2018, consistent with the forward market prices rather than the inflation forecast in the 2017 IRP.

4. Solar Capacity Contribution

In its February 25, 2019 comments, PacifiCorp requested that it be allowed to update its solar capacity contributions, just as the Staff Recommendation allowed for Portland General Electric (PGE). The information on PacifiCorp's updated solar capacity contributions incorporating the effect of additional solar penetration in its system was a part of its 2019 IRP public input process. The Commission declined to extend the Staff Recommendation on solar capacity contributions for PGE to PacifiCorp in Order No. 19-074. This is in part because, at the Commission's public meeting on February 26, 2019, as the Commission considered whether to adopt the Staff Recommendation, Staff mistakenly suggested that PacifiCorp's inputs were not complete and had not yet been subject to public review.

In contrast to Staff's representations, PacifiCorp's solar capacity contributions have been subject to an extensive public input process, where Staff and other stakeholders have had ample opportunities to consider the 2019 IRP details, including the details related to solar capacity contributions. PacifiCorp is not proposing to update the solar capacity contribution at this time, but notes that the existing methodology distorts Schedule 37 pricing in a manner that is inconsistent with customer indifference. The capacity contributions based on the 2017 IRP are quite high, particularly in light of the significant quantity of solar resources added to PacifiCorp's portfolio since that IRP was filed. This inflates prices for solar well above what the 2019 IRP, which includes the data related to greater solar penetration, suggests those prices should be, and therefore calls into question the continued use of the current methodology.

III. CONCLUSION

PacifiCorp respectfully asks the Commission to approve this interim Schedule 37 standard avoided cost update, including the additional enhancements to the Staff Recommendation as described above.[12] In the alternative PacifiCorp has provided the Commission interim avoided costs, which only include the enhancements set forth in the Staff Recommendation, consistent with Order No. 19-074.[13] Finally, if the Commission adopts avoided costs without adopting PacifiCorp's additional enhancements, PacifiCorp requests the Commission restrict QFs to only selecting the renewable avoided cost price stream.

[12] *See*, PacifiCorp OR Schedule 37 Filing, Attachments 9, 11 & 13.
[13] *See*, PacifiCorp OR Schedule 37 Filing, Attachments 7, 10 & 12.

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

By E-Mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon, 97232

Informal inquiries may be directed to me at (503) 813-5701.

Sincerely,

Etta Lockey
Vice President, Regulation

Revised Tariff Sheets

PACIFIC POWER
PROPOSED TARIFF CHANGES TO STANDARD RATES

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – MARCH 2019

Monthly Payments

A Qualifying Facility shall select the option of payment at the time of signing the contract under one of the Pricing Options specified above. Once an option is selected the option will remain in effect for the duration of the Facility's contract.

Renewable or Standard Fixed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the renewable or standard fixed prices as provided in this schedule. On-Peak and Off-Peak are defined in the definitions section of this schedule.

Firm Market Indexed and Non-Firm Market Index Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the market prices calculated at the time of delivery. On-Peak and Off-Peak are defined in the definitions section of this schedule.

Avoided Cost Prices

Standard Fixed Avoided Cost Prices for Base Load and Wind QF (¢/kWh)

Deliveries During Calendar Year	Base Load QF (1,3)		Wind QF (2,3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)
2019	3.54	2.43	3.48	2.37
2020	3.15	2.20	3.08	2.14
2021	3.18	2.41	3.12	2.35
2022	3.47	2.68	3.40	2.62
2023	3.71	2.90	3.65	2.84
2024	4.17	3.22	4.10	3.15
2025	4.48	3.46	4.41	3.39
2026	4.76	3.71	4.69	3.64
2027	4.73	3.72	4.66	3.65
2028	4.74	3.74	4.67	3.67
2029	5.12	4.07	5.05	3.99
2030	7.24	4.31	5.11	4.23
2031	7.53	4.55	5.36	4.47
2032	7.83	4.79	5.62	4.70
2033	8.13	5.02	5.87	4.94
2034	8.43	5.25	6.12	5.17
2035	8.29	5.05	5.93	4.96
2036	8.41	5.10	6.01	5.01

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(continued)

Avoided Cost Prices (Continued)

Standard Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (¢/kWh)

Deliveries During Calendar Year	Fixed Solar QF (2,3)		Tracking Solar QF (2,3)		
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	
	(e)	(f)	(g)	(h)	
2019	3.48	2.36	3.48	2.36	C
CC2020	3.08	2.13	3.08	2.13	
2021	3.11	2.34	3.11	2.34	
2022	3.40	2.61	3.40	2.61	
2023	3.64	2.83	3.64	2.83	
2024	4.10	3.15	4.10	3.15	
2025	4.40	3.39	4.40	3.39	
2026	4.69	3.63	4.69	3.63	
2027	4.66	3.64	4.66	3.64	
2028	4.66	3.66	4.66	3.66	
2029	5.04	3.98	5.04	3.98	
2030	8.44	4.23	8.65	4.23	
2031	8.77	4.46	8.98	4.46	
2032	9.10	4.70	9.31	4.70	
2033	9.42	4.93	9.64	4.93	
2034	9.74	5.16	9.97	5.16	
2035	9.63	4.95	9.86	4.95	
2036	9.78	5.01	10.01	5.01	C

(1) Capacity Contribution to Peak for Avoided Proxy Resource and Base Load QF resource are assumed 100%.

(2) The standard avoided cost price for wind and solar QFs located in PacifiCorp's balancing authority area (BAA) are reduced by an integration charge of $0.57/MWh ($2016) and solar integration charge of $0.60/MWh ($2016), respectively.

For Solar and Wind QFs not located in PacifiCorp's BAA, the renewable avoided cost price will be increased by wind integration charge of $0.57/MWh ($2016) and solar integration charge of $0.60/MWh ($2016), respectively.

(3) Standard Resource Sufficiency Period ends December 31, 2029 and Standard Resource Deficiency Period begins January 1, 2030.

(continued)

Avoided Cost Prices (Continued)

Renewable Fixed Avoided Cost Prices for Base Load and Wind QF (¢/kWh)

Deliveries During Calendar Year	Renewable Base Load QF (1,4)		Wind QF (1,2,3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)
2019	3.54	2.43	3.48	2.37
2020	3.15	2.20	3.08	2.14
2021	4.06	1.44	1.74	1.37
2022	4.13	1.51	1.76	1.45
2023	4.20	1.58	1.77	1.52
2024	4.30	1.62	1.82	1.55
2025	4.40	1.66	1.85	1.59
2026	4.49	1.71	1.89	1.64
2027	4.58	1.75	1.92	1.68
2028	4.68	1.80	1.96	1.72
2029	4.78	1.84	2.00	1.76
2030	4.88	1.88	2.04	1.81
2031	4.98	1.93	2.08	1.85
2032	5.08	1.98	2.12	1.90
2033	5.17	2.03	2.15	1.95
2034	5.28	2.07	2.20	1.99
2035	5.40	2.10	2.25	2.02
2036	5.51	2.14	2.30	2.05

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(continued)

Avoided Cost Prices (continued)

Renewable Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (¢/kWh)

Deliveries During Calendar Year	Fixed Solar QF (1,2,3) On-Peak Energy Price	Fixed Solar QF (1,2,3) Off-Peak Energy Price	Tracking Solar QF (1,2,3) On-Peak Energy Price	Tracking Solar QF (1,2,3) Off-Peak Energy Price
	(e)	(f)	(g)	(h)
2019	3.48	2.36	3.48	2.36
2020	3.08	2.13	3.08	2.13
2021	4.41	1.37	4.71	1.37
2022	4.49	1.44	4.80	1.44
2023	4.58	1.51	4.89	1.51
2024	4.68	1.54	5.01	1.54
2025	4.79	1.58	5.12	1.58
2026	4.89	1.63	5.22	1.63
2027	4.99	1.67	5.33	1.67
2028	5.09	1.72	5.45	1.72
2029	5.20	1.75	5.56	1.75
2030	5.31	1.80	5.68	1.80
2031	5.42	1.84	5.79	1.84
2032	5.53	1.89	5.91	1.89
2033	5.64	1.94	6.03	1.94
2034	5.75	1.98	6.15	1.98
2035	5.88	2.01	6.29	2.01
2036	6.00	2.05	6.42	2.05

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(1) For the purpose of determining: (i) when the Renewable Qualifying Facility is entitled to renewable avoided cost prices; and (ii) the ownership of environmental attributes and the transfer of Green Tags to PacifiCorp, Renewable Sufficiency Period ends December 31, 2020 and Renewable Deficiency Period begins January 1, 2021.

(2) During the Renewable Resource Sufficiency Period, the renewable avoided cost price for a wind and solar Qualifying Facility located in PacifiCorp's BAA is reduced by wind integration charge of \$0.57/MWh (\$2016) and solar integration charge of \$0.60/MWh (\$2016), respectively.
For Solar and Wind QFs not located in PacifiCorp's BAA, the renewable avoided cost price will be increased by the avoided wind integration charge of \$0.57/MWh (\$2016) and solar integration charge of \$0.60/MWh (\$2016), respectively.

(3) During the Renewable Resource Deficiency Period, the renewable avoided cost price for a solar Qualifying Facility located in PacifiCorp's BAA (in-system) is reduced by the difference between the solar integration charge\$0.60/MWh (\$2016) and wind integration charge of\$0.57/MWh (\$2016). For a wind Qualifying Facility located in PacifiCorp's (BAA), the adjustment is zero. For a solar Qualifying Facility not located in PacifiCorp's BAA, the renewable avoided cost price for solar QF will be increased by the difference between the solar integration and wind integration charges.

(4) During the Renewable Resource Deficiency Period, the renewable avoided cost price for Base Load is increased by the avoided wind integration charge of \$0.57/MWh (\$2016).

(continued)

Appendix 1

PACIFIC POWER
AVOIDED COST CALCULATION-STAFF PROPOSAL

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – MARCH 2019

Updates based on OPUC staff memo dated 2019 02 20

1 Capital costs of Avoided Cost resources (SCCT,CCCT, and Wind) based on 2019 IRP Supply Side Table, but without applying 2019 IRP deescalation
2 Fixed Operations and Maintenance (O&M) costs - 2019 IRP Supply-Side Table
3 Capacity factor of avoided renewable resource (wind) - 2019 IRP Supply-side Table
4 Updated forward electricity and natural gas prices - Dec. 2018 OFPC, without updating inflation
5 Changes to status of PTC - none for 2021 wind

15 Year (2019 - 2033) Nominal levelized Price at 6.920% Discount Rate (1)

	Non-Renewable			Renewable			Renewable vs. Non-Renewable	
	Current	per Order	Change	Current	per Order	Change	Current	per Order
Baseload	$37.14	$40.40	$3.26	$40.93	$31.99	($8.94)	$3.79	($8.41)
Wind	$34.47	$37.80	$3.33	$28.92	$19.98	($8.95)	($5.55)	($17.82)
Fixed Solar	$41.35	$45.33	$3.99	$50.10	$41.34	($8.76)	$8.76	($3.99)
Tracking Solar	$41.58	$45.55	$3.97	$52.16	$43.41	($8.75)	$10.59	($2.14)

PacifiCorp Illustrative Updates

1 Renewable rate less non-renewable rate equals RPS Compliance Cost (July 12, 2018 value of $1.92/MWh (2017$)) during renewable sufficiency peric
2 Wind and solar costs and characteristics from 2019 IRP - applied to wind and solar only

Exhibit 1
Standard Avoided Cost Prices for Base Load QF (1)
$/MWH

	Standard Avoided Resource		Base Load QF Resource				
Year	Avoided Firm Capacity Costs	Energy Only Price	Capacity Contribution	QF Capacity Adder	Capacity Adder Allocated to On-Peak Hours	On-Peak	Off-Peak
	$/kW-yr	$/MWh		($/kW-yr)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				= (a) * (c)	(d) *1000 / (100.0% x 8760 x 56%)	(e) + (b)	= (b)
2019	Market Based Prices					$35.42	$24.26
2020	2019 through 2029					$31.45	$21.97
2021						$31.78	$24.11
2022						$34.65	$26.79
2023						$37.14	$29.00
2024						$41.70	$32.19
2025						$44.75	$34.61
2026						$47.62	$37.05
2027						$47.34	$37.19
2028						$47.38	$37.42
2029						$51.21	$40.65
2030	$143.51	$43.12	100.0%	143.51	$29.23	$72.35	$43.12
2031	$146.58	$45.48	100.0%	146.58	$29.86	$75.34	$45.48
2032	$149.66	$47.85	100.0%	149.66	$30.48	$78.34	$47.85
2033	$152.77	$50.22	100.0%	152.77	$31.12	$81.34	$50.22
2034	$155.92	$52.53	100.0%	155.92	$31.76	$84.29	$52.53
2035	$159.11	$50.50	100.0%	159.11	$32.41	$82.91	$50.50
2036	$162.36	$51.04	100.0%	162.36	$33.07	$84.11	$51.04

(1) Capacity Contribution of the Avoided Proxy and Base Load QF resources are assumed to be 100%.

Columns

- (a) Full fixed cost of a proxy CCCT less capitalized energy
- (b) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (e) 100.0% is the on-peak capacity factor of the Base Load QF resource
- (f) 56% is the percent of all hours that are on-peak
- (f) 2018-2029 On-Peak Blended Market Prices for QF resource
- (g) 2018-2029 Off-Peak Blended Market Prices for QF resource

Exhibit 2
Standard Avoided Cost Prices for Wind QF (1,2)
$/MWH

	Standard Avoided Resource		Wind QF Resource				
Year	Avoided Firm Capacity Costs	Energy Only Price	Capacity Contribution	QF Capacity Adder	Capacity Adder Allocated to On-Peak Hours	On-Peak	Off-Peak
	$/kW-yr	$/MWh		($/kW-yr)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				= (a) * (c)	(d) *1000 / (39.3% x 8760 x 56%)	= (b) + (e)	= (b)
2019	Market Based Prices					$34.82	$23.66
2020	2019 through 2029					$30.84	$21.36
2021	less Wind Integration (2)					$31.16	$23.49
2022						$34.02	$26.16
2023						$36.49	$28.35
2024						$41.03	$31.52
2025						$44.07	$33.93
2026						$46.93	$36.36
2027						$46.63	$36.48
2028						$46.65	$36.69
2029						$50.46	$39.90
2030	$143.51	$43.12	11.8%	16.90	$8.76	$51.11	$42.35
2031	$146.58	$45.48	11.8%	17.26	$8.95	$53.64	$44.69
2032	$149.66	$47.85	11.8%	17.62	$9.14	$56.18	$47.04
2033	$152.77	$50.22	11.8%	17.99	$9.32	$58.72	$49.39
2034	$155.92	$52.53	11.8%	18.36	$9.52	$61.20	$51.68
2035	$159.11	$50.50	11.8%	18.74	$9.71	$59.34	$49.63
2036	$162.36	$51.04	11.8%	19.12	$9.91	$60.06	$50.15

(1) The avoided cost price is reduced by a wind integration charge of $0.57/MWh ($2016) for wind QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If QF wind resource is not in PacifiCorp's BAA, prices will be increased by the $0.57/MWh ($2016) integration charges.

(2) Wind Integration Cost is $0.57 (2017 IRP Volume II-Appendix F)

Columns
- (a) Full fixed cost of a proxy CCCT less capitalized energy
- (b) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (c) Peak Capacity Contribution values for renewables (% of nameplate capacity), 2017 IRP
- (d) Column (c) multiplied by difference between capacity contributions of renewable Base Load QF and renewable proxy wind resource
- (e) 39.3% is the on-peak capacity factor of the Wind QF Resource
  56% is the percent of all hours that are on-peak
- (f) 2018-2029 On-Peak Blended Market Prices for QF resource
- (g) 2018-2029 Off-Peak Blended Market Prices for QF resource

Wind Capacity Contribution 11.8%

Exhibit 3
Standard Avoided Cost Prices for Fixed Solar QF
$/MWH

	Standard Avoided Resource		Fixed Solar QF				
Year	Capacity Price	Energy Only Price	Capacity Contribution	QF Capacity Adder	Capacity Adder Allocated to On-Peak Hours	On-Peak	Off-Peak
	$/kW-yr	$/MWh		($/kW-yr)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				= (a) * (c)	(d) *1000 / (37.3% x 8760 x 56%)	= (b) + (e)	= (b)
2019	Market Based Prices					$34.78	$23.62
2020	2019 through 2029					$30.80	$21.32
2021						$31.11	$23.44
2022						$33.96	$26.10
2023						$36.43	$28.29
2024						$40.97	$31.46
2025						$44.00	$33.86
2026						$46.85	$36.28
2027						$46.55	$36.40
2028						$46.57	$36.61
2029						$50.38	$39.82
2030	$143.51	$43.12	53.86%	$77.30	$42.18	$84.45	$42.27
2031	$146.58	$45.48	53.86%	$78.95	$43.08	$87.70	$44.61
2032	$149.66	$47.85	53.86%	$80.61	$43.99	$90.95	$46.96
2033	$152.77	$50.22	53.86%	$82.28	$44.90	$94.22	$49.31
2034	$155.92	$52.53	53.86%	$83.98	$45.83	$97.43	$51.60
2035	$159.11	$50.50	53.86%	$85.70	$46.77	$96.31	$49.55
2036	$162.36	$51.04	53.86%	$87.45	$47.72	$97.79	$50.07

(1) The avoided cost price is reduced by a solar integration charge of $0.60/MWh ($2016) for solar QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If QF solar resource is not in PacifiCorp's BAA, prices will be increased by the $0.60/MWh ($2016) integration charges.

(2) Solar Integration Cost is $0.60 (2017 IRP Volume II-Appendix F)

Columns
- (a) Full fixed cost of a proxy CCCT less capitalized energy
- (b) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (c) Peak Capacity Contribution values for renewables (% of nameplate capacity), 2017 IRP
- (d) Column (c) multiplied by the capacity contribution of a Standard Fixed Solar QF
- (e) 37.3% is the on-peak capacity factor of the Fixed Solar QF Resource
  56% is the percent of all hours that are on-peak
- (f) 2018-2029 On-Peak Blended Market Prices for QF resource
- (g) 2018-2029 Off-Peak Blended Market Prices for QF resource

Fixed Solar Capacity Contribution 53.9%

Exhibit 4
Standard Avoided Cost Prices for Tracking Solar QF
$/MWH

	Standard Avoided Resource		Tracking Solar QF				
Year	Capacity Price	Energy Only Price	Capacity Contribution	QF Capacity Adder	Capacity Adder Allocated to On-Peak Hours	On-Peak	Off-Peak
	$/kW-yr	$/MWh		($/kW-yr)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				= (a) * (c)	(d) *1000 / (42.8% x 8760 x 56%)	= (b) + (e)	= (b)
2019	Market Based Prices					$34.78	$23.62
2020	2019 through 2029					$30.80	$21.32
2021						$31.11	$23.44
2022						$33.96	$26.10
2023						$36.43	$28.29
2024						$40.97	$31.46
2025						$44.00	$33.86
2026						$46.85	$36.28
2027						$46.55	$36.40
2028						$46.57	$36.61
2029						$50.38	$39.82
2030	$143.51	$43.12	64.80%	93.00	$44.26	$86.53	$42.27
2031	$146.58	$45.48	64.80%	94.99	$45.21	$89.82	$44.61
2032	$149.66	$47.85	64.80%	96.98	$46.15	$93.12	$46.96
2033	$152.77	$50.22	64.80%	99.00	$47.11	$96.43	$49.31
2034	$155.92	$52.53	64.80%	101.04	$48.09	$99.69	$51.60
2035	$159.11	$50.50	64.80%	103.11	$49.07	$98.62	$49.55
2036	$162.36	$51.04	64.80%	105.21	$50.07	$100.14	$50.07

(1) The avoided cost price is reduced by a solar integration charge of $0.60/MWh ($2016) for solar QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system).
If QF solar resource is not in PacifiCorp's BAA, prices will be increased by the $0.60/MWh ($2016) integration charges.

(2) Solar Integration ($0.60 (2017 IRP Volume II-Appendix F)

Columns
(a) Full fixed cost of a proxy CCCT less capitalized energy
(b) Fuel and Capitalized Energy Cost of the Proxy CCCT
(c) Peak Capacity Contribution values for renewables (% of nameplate capacity), 2017 IRP
(d) Column (c) multiplied by the capacity contribution of a Standard Tracking Solar QF
(e) 42.8% is the on-peak capacity factor of the Tracking Solar QF Resource
56% is the percent of all hours that are on-peak
(f) 2018-2029 On-Peak Blended Market Prices for QF resource
(g) 2018-2029 Off-Peak Blended Market Prices for QF resource

Tracking Solar Capacity Contribution 64.8%

Exhibit 5

Renewable Standard Avoided Cost Prices for Base Load QF(1)
$/MWH

Year	Renewable Wind Avoided Resource On-Peak ($/MWh) (a)	Renewable Wind Avoided Resource Off-Peak ($/MWh) (b)	Renewable Base Load QF Resource Avoided Firm Capacity Costs $/kW-yr (c)	QF Capacity Adder ($/kW-yr) (d) (c) x 84%	Capacity Adder Allocated to On-Peak Hours ($/MWh) (e) (d) *1000 / (100.0%x 8760 x 56%)	On-Peak $/MWh (f) = (a) + (e)	Off-Peak $/MWh (g) = (b)
2019						$35.42	$24.26
2020						$31.45	$21.97
2021	$19.86	$13.74	$117.10	$98.60	$20.08	$40.56	$14.36
2022	$20.06	$14.48	$120.05	$101.08	$20.59	$41.28	$15.11
2023	$20.29	$15.17	$122.90	$103.48	$21.08	$42.02	$15.82
2024	$20.78	$15.48	$125.77	$105.90	$21.57	$43.02	$16.15
2025	$21.21	$15.90	$128.69	$108.36	$22.07	$43.96	$16.58
2026	$21.61	$16.36	$131.62	$110.82	$22.57	$44.87	$17.05
2027	$22.03	$16.81	$134.52	$113.27	$23.07	$45.81	$17.52
2028	$22.48	$17.24	$137.44	$115.72	$23.57	$46.78	$17.97
2029	$22.95	$17.62	$140.44	$118.25	$24.09	$47.79	$18.37
2030	$23.41	$18.05	$143.51	$120.84	$24.61	$48.79	$18.82
2031	$23.83	$18.49	$146.58	$123.42	$25.14	$49.76	$19.28
2032	$24.28	$18.98	$149.66	$126.01	$25.67	$50.76	$19.79
2033	$24.71	$19.46	$152.77	$128.63	$26.20	$51.74	$20.29
2034	$25.21	$19.89	$155.92	$131.28	$26.74	$52.80	$20.74
2035	$25.83	$20.15	$159.11	$133.97	$27.29	$53.99	$21.02
2036	$26.37	$20.54	$162.36	$136.71	$27.85	$55.11	$21.43

Columns
- (a) Table 13 Column (d)
- (b) Table 13 Column (e)
- (c) Full fixed cost of a proxy CCCT less capitalized energy
- (d) Column (c) multiplied by difference between capacity contributions of renewable Base Load QF and renewable proxy wind resource
- (e) 100.0% is the on-peak capacity factor of the Proxy CCCT Resource
  56% is the percent of all hours that are on-peak
- (f) 2019-2020 On-Peak Blended Market Prices for QF resource
- (g) 2019-2020 Off-Peak Blended Market Prices for QF resource

(1) The renewable avoided cost prices during the deficiency period are increased by the avoided integration charge

Exhibit 6
Renewable Standard Avoided Cost Prices for Wind QF (1) (2) (3)
$/MWH

Year	Renewable Wind Avoided Resource		Wind QF Resource			Wind QF Resource	
	On-Peak	Off-Peak	Avoided Firm Capacity Costs	QF Capacity Adder	Capacity Adder Allocated to On-Peak Hours	On-Peak	Off-Peak
	($/MWh)	($/MWh)	$/kW-yr	($/kW-yr)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				(c) x -4%	(d) *1000 / (39.3%x 8760 x 56%)	= (a) + (e)	= (b)
2019						$34.82	$23.66
2020						$30.84	$21.36
2021	$19.86	$13.74	$117.10	($4.71)	($2.44)	$17.42	$13.74
2022	$20.06	$14.48	$120.05	($4.83)	($2.50)	$17.56	$14.48
2023	$20.29	$15.17	$122.90	($4.94)	($2.56)	$17.73	$15.17
2024	$20.78	$15.48	$125.77	($5.06)	($2.62)	$18.16	$15.48
2025	$21.21	$15.90	$128.69	($5.18)	($2.68)	$18.53	$15.90
2026	$21.61	$16.36	$131.62	($5.30)	($2.74)	$18.87	$16.36
2027	$22.03	$16.81	$134.52	($5.41)	($2.81)	$19.22	$16.81
2028	$22.48	$17.24	$137.44	($5.53)	($2.87)	$19.61	$17.24
2029	$22.95	$17.62	$140.44	($5.65)	($2.93)	$20.02	$17.62
2030	$23.41	$18.05	$143.51	($5.77)	($2.99)	$20.42	$18.05
2031	$23.83	$18.49	$146.58	($5.90)	($3.06)	$20.77	$18.49
2032	$24.28	$18.98	$149.66	($6.02)	($3.12)	$21.16	$18.98
2033	$24.71	$19.46	$152.77	($6.15)	($3.19)	$21.52	$19.46
2034	$25.21	$19.89	$155.92	($6.27)	($3.25)	$21.96	$19.89
2035	$25.83	$20.15	$159.11	($6.40)	($3.32)	$22.51	$20.15
2036	$26.37	$20.54	$162.36	($6.53)	($3.39)	$22.98	$20.54

(1) During the deficiency period, avoided cost prices will be adjusted by the difference between the avoided integration costs and QF's integration costs. If the QF is in PacifiCorp's Balancing Area Authority (BAA), the adjustment is zero (integration costs cancel each other out).
If QF wind resource is not in PacifiCorp's BAA, $0.57/MWh ($2016) will be added for avoided integration charges.

(2) During the sufficiency period, avoided cost prices are reduced by an integration charge of $0.57/MWh ($2016) for wind QF resources located in PacifiCorp's BAA (in-system).
If QF wind resource is not in PacifiCorp's BAA, prices will be increased by the $0.57/MWh ($2016) integration charges.

(3) Wind Integration Charge is $0.57 (2017 IRP Volume II-Appendix F)

Columns
- (a) Table 13 Column (d)
- (b) Table 13 Column (e)
- (c) Full fixed cost of a proxy CCCT less capitalized energy
- (d) Column (c) multiplied by difference between capacity contributions of renewable Wind QF and renewable proxy wind resource
- (e) 39.3% is the on-peak capacity factor of the Wind QF resource
  56% is the percent of all hours that are on-peak
- (f) 2019-2020 On-Peak Blended Market Prices for QF resource
- (g) 2019-2020 Off-Peak Blended Market Prices for QF resource

Exhibit 7

Renewable Standard Avoided Cost Prices for Fixed Solar QF (1)
$/MWH

Year	Renewable Wind Avoided Resource		Fixed Solar QF Resource			Fixed Solar QF	
	On-Peak	Off-Peak	Avoided Firm Capacity Costs	QF Capacity Adder	Capacity Adder Allocated to On-Peak Hours	On-Peak	Off-Peak
	($/MWh)	($/MWh)	$/kW-yr	($/kW-yr)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				(c) x 38.1%	(d) *1000 / (37.3%x 8760 x 56%)	= (a) + (e)	= (b)
2019						$34.78	$23.62
2020						$30.80	$21.32
2021	$19.86	$13.74	$117.10	$44.57	$24.32	$44.13	$13.69
2022	$20.06	$14.48	$120.05	$45.69	$24.94	$44.94	$14.42
2023	$20.29	$15.17	$122.90	$46.78	$25.53	$45.76	$15.11
2024	$20.78	$15.48	$125.77	$47.87	$26.12	$46.84	$15.42
2025	$21.21	$15.90	$128.69	$48.98	$26.73	$47.87	$15.83
2026	$21.61	$16.36	$131.62	$50.10	$27.34	$48.87	$16.28
2027	$22.03	$16.81	$134.52	$51.20	$27.94	$49.89	$16.73
2028	$22.48	$17.24	$137.44	$52.31	$28.55	$50.95	$17.16
2029	$22.95	$17.62	$140.44	$53.45	$29.17	$52.04	$17.54
2030	$23.41	$18.05	$143.51	$54.62	$29.81	$53.14	$17.97
2031	$23.83	$18.49	$146.58	$55.79	$30.45	$54.20	$18.41
2032	$24.28	$18.98	$149.66	$56.96	$31.09	$55.29	$18.90
2033	$24.71	$19.46	$152.77	$58.15	$31.73	$56.36	$19.38
2034	$25.21	$19.89	$155.92	$59.35	$32.39	$57.52	$19.81
2035	$25.83	$20.15	$159.11	$60.56	$33.05	$58.80	$20.07
2036	$26.37	$20.54	$162.36	$61.80	$33.72	$60.01	$20.46

Columns
- (a) Table 13 Column (d)
- (b) Table 13 Column (e)
- (c) Full fixed cost of a proxy CCCT less capitalized energy
- (d) Column (c) multiplied by difference between capacity contributions of Fixed Solar QF and renewable proxy wind resource.
- (e) 37.3% is the on-peak capacity factor of the Fixed Solar QF resource
  56% is the percent of all hours that are on-peak
- (f) 2019-2020 On-Peak Blended Market Prices for QF resource
- (g) 2019-2020 Off-Peak Blended Market Prices for QF resource

(1) Adjustment for integration costs:
During Renewable Sufficiency period, the prices are decreased by Solar integration charges
During Renewable Deficiency Period, the prices are decreased by the difference in Wind and Solar integration charge

Exhibit 8

Renewable Standard Avoided Cost Prices for Tracking Solar QF (1)
$/MWH

Year	Renewable Wind Avoided Resource On-Peak ($/MWh) (a)	Renewable Wind Avoided Resource Off-Peak ($/MWh) (b)	Tracking Solar QF Resource Avoided Firm Capacity Costs $/kW-yr (c)	QF Capacity Adder ($/kW-yr) (d) (c) x 49.0%	Capacity Adder Allocated to On-Peak Hours ($/MWh) (e) (d) *1000 / (42.8%x 8760 x 56%)	Tracking Solar QF On-Peak $/MWh (f) = (a) + (e)	Tracking Solar QF Off-Peak $/MWh (g) = (b)
2019						$34.78	$23.62
2020						$30.80	$21.32
2021	$19.86	$13.74	$117.10	$57.38	$27.31	$47.12	$13.69
2022	$20.06	$14.48	$120.05	$58.83	$28.00	$48.00	$14.42
2023	$20.29	$15.17	$122.90	$60.22	$28.66	$48.89	$15.11
2024	$20.78	$15.48	$125.77	$61.63	$29.33	$50.05	$15.42
2025	$21.21	$15.90	$128.69	$63.06	$30.01	$51.15	$15.83
2026	$21.61	$16.36	$131.62	$64.50	$30.69	$52.22	$16.28
2027	$22.03	$16.81	$134.52	$65.92	$31.37	$53.32	$16.73
2028	$22.48	$17.24	$137.44	$67.35	$32.05	$54.45	$17.16
2029	$22.95	$17.62	$140.44	$68.82	$32.75	$55.62	$17.54
2030	$23.41	$18.05	$143.51	$70.32	$33.47	$56.80	$17.97
2031	$23.83	$18.49	$146.58	$71.83	$34.18	$57.93	$18.41
2032	$24.28	$18.98	$149.66	$73.34	$34.90	$59.10	$18.90
2033	$24.71	$19.46	$152.77	$74.86	$35.63	$60.26	$19.38
2034	$25.21	$19.89	$155.92	$76.41	$36.36	$61.49	$19.81
2035	$25.83	$20.15	$159.11	$77.97	$37.11	$62.86	$20.07
2036	$26.37	$20.54	$162.36	$79.56	$37.86	$64.15	$20.46

Columns
- (a) Table 13 Column (d)
- (b) Table 13 Column (e)
- (c) Full fixed cost of a proxy CCCT less capitalized energy
- (d) Column (c) multiplied by difference between capacity contribution of Tracking Solar QF and renewable proxy wind resource.
- (e) 42.8% is the on-peak capacity factor of the Tracking Solar QF Resource
  56% is the percent of all hours that are on-peak
- (f) 2019-2020 On-Peak Blended Market Prices for QF resource
- (g) 2019-2020 Off-Peak Blended Market Prices for QF resource

(1) Adjustment for integration costs:
During Renewable Sufficiency period, the prices are decreased by Solar integration charges
During Renewable Deficiency Period, the prices are decreased by the difference in Wind and Solar integration charge

Exhibit 9
Market Price - Blending Matrix (1)

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2019	1.5%	36.7%	61.8%	100.0%	2.2%	20.5%	77.4%	100.0%
2/1/2019	1.8%	27.7%	70.4%	100.0%	2.6%	38.2%	59.2%	100.0%
3/1/2019	0.0%	52.3%	47.7%	100.0%	3.0%	70.6%	26.4%	100.0%
4/1/2019	0.6%	47.7%	51.7%	100.0%	0.5%	42.8%	56.7%	100.0%
5/1/2019	5.0%	65.8%	29.3%	100.0%	10.0%	63.1%	26.9%	100.0%
6/1/2019	2.9%	88.2%	8.9%	100.0%	4.6%	90.4%	5.1%	100.0%
7/1/2019	17.1%	74.0%	9.0%	100.0%	11.3%	88.7%	0.0%	100.0%
8/1/2019	14.1%	71.1%	14.8%	100.0%	6.5%	93.5%	0.0%	100.0%
9/1/2019	5.0%	92.4%	2.6%	100.0%	2.8%	97.2%	0.0%	100.0%
10/1/2019	0.0%	36.7%	63.3%	100.0%	0.0%	17.8%	82.2%	100.0%
11/1/2019	0.0%	14.6%	85.4%	100.0%	0.0%	16.9%	83.1%	100.0%
12/1/2019	0.0%	27.2%	72.8%	100.0%	0.0%	2.3%	97.7%	100.0%
1/1/2020	0.0%	6.8%	93.2%	100.0%	0.0%	30.0%	70.0%	100.0%
2/1/2020	4.5%	34.1%	61.4%	100.0%	13.9%	6.2%	79.9%	100.0%
3/1/2020	0.0%	50.5%	49.5%	100.0%	1.7%	43.4%	54.8%	100.0%
4/1/2020	2.9%	28.3%	68.8%	100.0%	8.4%	66.0%	25.6%	100.0%
5/1/2020	0.8%	34.4%	64.8%	100.0%	16.9%	50.0%	33.1%	100.0%
6/1/2020	3.1%	88.1%	8.8%	100.0%	23.8%	54.2%	22.0%	100.0%
7/1/2020	19.7%	70.9%	9.3%	100.0%	8.6%	91.4%	0.0%	100.0%
8/1/2020	20.1%	74.0%	5.9%	100.0%	6.0%	73.6%	20.4%	100.0%
9/1/2020	9.0%	86.2%	4.8%	100.0%	0.0%	98.6%	1.4%	100.0%
10/1/2020	0.0%	33.4%	66.6%	100.0%	0.0%	15.9%	84.1%	100.0%
11/1/2020	0.0%	6.4%	93.6%	100.0%	0.0%	3.9%	96.1%	100.0%
12/1/2020	2.6%	25.3%	72.0%	100.0%	0.0%	41.4%	58.6%	100.0%
1/1/2021	0.0%	19.5%	80.5%	100.0%	0.0%	0.0%	100.0%	100.0%
2/1/2021	0.9%	12.9%	86.3%	100.0%	15.5%	23.3%	61.2%	100.0%
3/1/2021	0.0%	30.5%	69.5%	100.0%	2.3%	50.5%	47.2%	100.0%
4/1/2021	0.0%	20.3%	79.7%	100.0%	5.5%	44.1%	50.4%	100.0%
5/1/2021	0.5%	29.6%	69.9%	100.0%	3.7%	73.2%	23.1%	100.0%
6/1/2021	8.5%	87.0%	4.6%	100.0%	4.6%	90.0%	5.4%	100.0%
7/1/2021	11.3%	82.6%	6.2%	100.0%	4.3%	93.6%	2.1%	100.0%
8/1/2021	4.2%	93.3%	2.4%	100.0%	4.1%	92.2%	3.7%	100.0%
9/1/2021	3.9%	90.5%	5.6%	100.0%	0.0%	100.0%	0.0%	100.0%
10/1/2021	0.0%	4.3%	95.7%	100.0%	0.0%	15.2%	84.8%	100.0%
11/1/2021	0.0%	0.0%	100.0%	100.0%	0.0%	0.0%	100.0%	100.0%
12/1/2021	0.0%	10.7%	89.3%	100.0%	0.0%	0.0%	100.0%	100.0%

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2022	0.0%	4.8%	95.2%	100.0%	0.0%	0.0%	100.0%	100.0%
2/1/2022	1.6%	39.6%	58.8%	100.0%	4.1%	25.1%	70.8%	100.0%
3/1/2022	9.2%	37.8%	53.0%	100.0%	7.0%	65.5%	27.5%	100.0%
4/1/2022	0.0%	29.3%	70.7%	100.0%	6.5%	71.7%	21.8%	100.0%
5/1/2022	1.5%	34.8%	63.7%	100.0%	17.8%	79.7%	2.4%	100.0%
6/1/2022	14.3%	75.6%	10.2%	100.0%	58.1%	31.6%	10.3%	100.0%
7/1/2022	10.6%	84.9%	4.5%	100.0%	6.5%	76.9%	16.6%	100.0%
8/1/2022	3.7%	93.8%	2.5%	100.0%	2.3%	80.0%	17.7%	100.0%
9/1/2022	2.0%	81.6%	16.4%	100.0%	0.0%	87.5%	12.5%	100.0%
10/1/2022	0.0%	31.5%	68.5%	100.0%	0.0%	26.6%	73.4%	100.0%
11/1/2022	1.0%	20.3%	78.7%	100.0%	0.0%	4.3%	95.7%	100.0%
12/1/2022	0.8%	20.7%	78.5%	100.0%	0.0%	6.5%	93.5%	100.0%
1/1/2023	0.0%	3.2%	96.8%	100.0%	0.0%	0.0%	100.0%	100.0%
2/1/2023	8.9%	14.8%	76.3%	100.0%	12.6%	39.1%	48.3%	100.0%
3/1/2023	22.0%	36.8%	41.2%	100.0%	8.6%	58.5%	32.9%	100.0%
4/1/2023	10.8%	19.9%	69.3%	100.0%	23.8%	51.7%	24.5%	100.0%
5/1/2023	33.2%	51.4%	15.4%	100.0%	28.0%	65.0%	7.0%	100.0%
6/1/2023	26.1%	67.1%	6.7%	100.0%	42.8%	47.0%	10.2%	100.0%
7/1/2023	35.5%	40.7%	23.8%	100.0%	36.1%	63.1%	0.8%	100.0%
8/1/2023	35.2%	51.8%	13.0%	100.0%	19.3%	66.8%	13.8%	100.0%
9/1/2023	1.8%	49.8%	48.4%	100.0%	0.0%	0.0%	100.0%	100.0%
10/1/2023	6.2%	43.8%	50.0%	100.0%	1.6%	24.5%	73.9%	100.0%
11/1/2023	8.9%	0.0%	91.1%	100.0%	25.2%	39.6%	35.2%	100.0%
12/1/2023	23.3%	36.6%	40.1%	100.0%	0.8%	21.6%	77.6%	100.0%
1/1/2024	0.0%	12.6%	87.4%	100.0%	12.3%	2.1%	85.6%	100.0%
2/1/2024	8.9%	9.4%	81.6%	100.0%	10.6%	27.4%	62.0%	100.0%
3/1/2024	14.1%	39.3%	46.6%	100.0%	14.9%	60.7%	24.4%	100.0%
4/1/2024	13.8%	27.8%	58.4%	100.0%	10.6%	64.5%	24.9%	100.0%
5/1/2024	33.6%	46.1%	20.4%	100.0%	14.0%	81.0%	5.0%	100.0%
6/1/2024	25.0%	63.3%	11.7%	100.0%	32.1%	61.6%	6.3%	100.0%
7/1/2024	29.2%	58.0%	12.9%	100.0%	38.6%	56.9%	4.5%	100.0%
8/1/2024	26.4%	55.4%	18.2%	100.0%	56.8%	41.7%	1.4%	100.0%
9/1/2024	9.1%	66.3%	24.6%	100.0%	36.0%	47.4%	16.6%	100.0%
10/1/2024	5.8%	58.2%	36.0%	100.0%	6.2%	26.8%	66.9%	100.0%
11/1/2024	12.3%	42.9%	44.8%	100.0%	0.6%	17.0%	82.4%	100.0%
12/1/2024	29.2%	52.3%	18.6%	100.0%	1.8%	5.9%	92.3%	100.0%
1/1/2025	0.4%	13.5%	86.1%	100.0%	5.7%	3.0%	91.3%	100.0%
2/1/2025	21.7%	17.2%	61.1%	100.0%	7.4%	25.9%	66.7%	100.0%
3/1/2025	30.7%	31.8%	37.5%	100.0%	8.8%	51.4%	39.8%	100.0%
4/1/2025	14.6%	29.6%	55.8%	100.0%	17.4%	63.7%	18.9%	100.0%
5/1/2025	42.1%	50.5%	7.4%	100.0%	12.0%	80.2%	7.9%	100.0%
6/1/2025	28.0%	61.3%	10.6%	100.0%	43.6%	53.7%	2.7%	100.0%
7/1/2025	31.2%	55.4%	13.4%	100.0%	40.1%	55.7%	4.2%	100.0%
8/1/2025	26.7%	73.3%	0.0%	100.0%	39.0%	49.9%	11.1%	100.0%
9/1/2025	24.9%	51.9%	23.2%	100.0%	31.6%	27.8%	40.6%	100.0%
10/1/2025	9.0%	47.8%	43.2%	100.0%	5.3%	22.1%	72.6%	100.0%
11/1/2025	10.6%	54.6%	34.8%	100.0%	14.1%	51.4%	34.5%	100.0%
12/1/2025	23.9%	38.4%	37.7%	100.0%	18.2%	23.4%	58.4%	100.0%
1/1/2026	0.0%	14.8%	85.2%	100.0%	3.1%	1.7%	95.3%	100.0%
2/1/2026	15.1%	10.4%	74.5%	100.0%	12.0%	23.4%	64.6%	100.0%
3/1/2026	21.6%	38.3%	40.0%	100.0%	14.2%	63.8%	22.0%	100.0%
4/1/2026	10.5%	22.1%	67.4%	100.0%	16.2%	67.9%	15.9%	100.0%
5/1/2026	25.9%	62.0%	12.2%	100.0%	32.8%	55.0%	12.2%	100.0%
6/1/2026	19.1%	71.1%	9.8%	100.0%	22.4%	75.0%	2.6%	100.0%
7/1/2026	35.1%	57.6%	7.4%	100.0%	49.4%	48.8%	1.8%	100.0%
8/1/2026	29.7%	55.9%	14.3%	100.0%	41.3%	53.6%	5.1%	100.0%
9/1/2026	4.9%	70.6%	24.5%	100.0%	32.4%	46.9%	20.7%	100.0%
10/1/2026	10.8%	57.7%	31.5%	100.0%	3.6%	23.9%	72.5%	100.0%
11/1/2026	11.3%	73.2%	15.5%	100.0%	28.7%	62.4%	8.9%	100.0%
12/1/2026	26.6%	33.8%	39.6%	100.0%	33.8%	23.8%	42.5%	100.0%

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2027	1.3%	19.5%	79.2%	100.0%	8.3%	0.0%	91.7%	100.0%
2/1/2027	16.7%	21.7%	61.7%	100.0%	22.3%	21.2%	56.6%	100.0%
3/1/2027	7.0%	47.0%	46.0%	100.0%	0.1%	73.1%	26.8%	100.0%
4/1/2027	22.3%	25.0%	52.7%	100.0%	13.4%	73.0%	13.6%	100.0%
5/1/2027	29.5%	62.7%	7.7%	100.0%	16.6%	67.5%	15.9%	100.0%
6/1/2027	22.3%	62.4%	15.3%	100.0%	30.7%	59.8%	9.5%	100.0%
7/1/2027	28.2%	64.4%	7.4%	100.0%	43.8%	54.5%	1.7%	100.0%
8/1/2027	6.2%	79.6%	14.2%	100.0%	38.3%	50.4%	11.2%	100.0%
9/1/2027	5.2%	79.5%	15.3%	100.0%	40.5%	58.4%	1.1%	100.0%
10/1/2027	9.7%	73.4%	16.8%	100.0%	9.9%	24.5%	65.6%	100.0%
11/1/2027	8.5%	75.4%	16.2%	100.0%	17.3%	48.9%	33.8%	100.0%
12/1/2027	28.5%	33.7%	37.8%	100.0%	36.7%	21.8%	41.6%	100.0%
1/1/2028	2.6%	26.7%	70.6%	100.0%	7.6%	1.7%	90.7%	100.0%
2/1/2028	17.7%	4.7%	77.6%	100.0%	29.0%	11.3%	59.7%	100.0%
3/1/2028	15.4%	31.7%	52.8%	100.0%	10.6%	57.7%	31.7%	100.0%
4/1/2028	23.8%	43.2%	33.0%	100.0%	15.5%	70.9%	13.5%	100.0%
5/1/2028	36.2%	56.9%	6.9%	100.0%	25.7%	65.3%	8.9%	100.0%
6/1/2028	25.4%	63.4%	11.1%	100.0%	34.4%	48.0%	17.6%	100.0%
7/1/2028	16.7%	62.9%	20.5%	100.0%	27.8%	67.6%	4.6%	100.0%
8/1/2028	20.1%	48.9%	31.0%	100.0%	13.9%	72.1%	14.0%	100.0%
9/1/2028	9.5%	51.2%	39.3%	100.0%	36.1%	59.3%	4.5%	100.0%
10/1/2028	7.1%	67.8%	25.2%	100.0%	0.0%	15.1%	84.9%	100.0%
11/1/2028	13.2%	60.0%	26.7%	100.0%	21.6%	52.1%	26.3%	100.0%
12/1/2028	20.7%	34.9%	44.5%	100.0%	28.3%	43.7%	28.0%	100.0%
1/1/2029	2.9%	32.2%	64.9%	100.0%	12.0%	16.0%	72.0%	100.0%
2/1/2029	4.4%	16.7%	78.9%	100.0%	20.6%	14.1%	65.2%	100.0%
3/1/2029	7.6%	40.4%	51.9%	100.0%	8.7%	27.5%	63.8%	100.0%
4/1/2029	19.3%	43.8%	36.9%	100.0%	1.8%	74.7%	23.5%	100.0%
5/1/2029	31.1%	51.9%	17.0%	100.0%	20.4%	72.6%	7.0%	100.0%
6/1/2029	30.8%	50.3%	18.9%	100.0%	21.3%	46.7%	32.1%	100.0%
7/1/2029	5.8%	70.2%	24.0%	100.0%	13.9%	72.0%	14.1%	100.0%
8/1/2029	18.8%	42.0%	39.1%	100.0%	5.5%	74.0%	20.5%	100.0%
9/1/2029	11.0%	48.4%	40.7%	100.0%	12.2%	81.6%	6.2%	100.0%
10/1/2029	15.0%	49.5%	35.6%	100.0%	28.3%	53.2%	18.4%	100.0%
11/1/2029	10.7%	57.6%	31.7%	100.0%	17.1%	60.5%	22.3%	100.0%
12/1/2029	27.8%	42.1%	30.1%	100.0%	32.5%	54.8%	12.8%	100.0%

(1) Blending weights are calculated using system balancing purchases and sales from GRID run using December 2018 Official Forward Market Price Curve

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

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

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

Table 2
Avoided Costs ($/MWh)
Energy Prices

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak (HLH Market Purchase)												
2019	37.26	33.78	26.57	23.23	20.91	30.95	57.81	70.09	39.17	27.26	26.83	31.16
2020	28.98	28.71	24.99	21.33	21.79	22.86	50.26	54.02	46.02	24.69	24.41	29.32
2021	29.18	27.60	25.10	21.34	22.02	24.49	49.94	54.32	49.63	25.07	24.66	28.01
2022	28.15	32.54	29.43	27.02	26.52	26.29	47.84	53.14	49.13	30.73	31.15	33.82
2023	33.64	35.31	32.69	32.26	28.69	26.74	47.56	52.28	47.21	35.12	36.15	38.08
2024	39.61	39.30	35.23	34.12	32.03	29.33	51.56	59.46	57.71	42.03	37.50	42.49
2025	43.60	44.00	38.69	37.02	33.69	31.62	54.37	63.83	61.94	42.52	40.20	45.52
2026	47.73	47.38	43.10	41.00	35.79	33.71	57.53	66.23	63.17	45.05	43.02	47.77
2027	49.58	49.34	42.51	38.99	35.10	33.91	55.30	64.72	62.58	46.98	41.78	47.34
2028	50.02	49.05	42.39	38.10	35.60	33.31	58.10	65.76	60.09	45.02	42.27	48.87
2029	52.36	51.09	45.45	42.11	38.09	35.38	61.86	74.56	66.93	49.07	46.03	51.63
2030	57.10	56.15	48.94	44.39	42.28	38.43	70.87	80.00	74.48	56.63	50.62	56.73
2031	61.83	61.01	52.56	46.86	44.23	43.12	74.33	82.65	76.45	56.71	52.73	59.34
2032	63.76	62.97	56.30	52.29	46.12	45.11	78.00	85.14	79.34	59.70	56.21	62.55
2033	67.61	66.68	57.85	51.34	49.13	49.69	83.69	89.84	84.24	65.73	59.12	66.03
2034	71.26	70.14	60.98	54.35	52.39	51.64	87.64	93.27	84.72	65.76	62.35	68.97
2035	74.88	73.84	61.34	55.21	48.85	46.79	85.01	99.82	86.92	64.24	59.28	65.00
2036	72.38	70.76	61.25	53.97	50.08	51.08	90.77	99.29	91.98	69.77	61.38	68.79
Off-Peak (LLH Market Purchase)												
2019	33.08	29.81	22.12	17.94	13.69	15.10	27.16	34.42	24.81	22.66	23.45	26.83
2020	26.62	24.97	22.09	14.89	14.42	13.92	24.70	28.78	24.58	21.90	21.50	25.30
2021	25.41	24.80	21.73	18.70	15.67	13.43	29.19	34.16	32.35	24.22	23.81	25.84
2022	26.82	27.31	24.56	22.83	18.78	17.55	30.60	34.90	33.50	27.04	28.07	29.48
2023	30.15	29.96	27.73	27.53	22.92	18.44	29.62	35.01	35.32	29.82	29.15	32.40
2024	33.20	33.26	29.77	28.85	25.85	19.63	32.94	39.71	40.91	34.50	32.19	35.48
2025	36.47	36.91	32.76	30.90	28.10	19.59	35.09	44.48	44.30	35.86	33.49	37.36
2026	40.19	40.34	35.75	34.45	30.26	20.66	38.31	46.99	46.21	37.76	35.02	38.66
2027	42.16	41.53	35.28	31.81	30.03	22.07	37.72	46.57	45.93	39.28	35.13	38.70
2028	42.34	41.66	35.45	31.42	29.69	24.07	38.80	46.81	45.13	38.86	34.98	39.85
2029	43.23	43.75	40.62	36.22	31.09	27.65	43.06	52.68	50.88	39.78	37.39	41.44
2030	46.48	47.62	42.84	38.58	34.61	29.74	48.73	59.02	56.96	45.70	41.81	46.02
2031	50.71	50.83	46.61	40.12	37.31	31.06	52.56	62.56	58.75	46.05	43.17	47.94
2032	51.69	52.65	48.76	45.42	39.61	31.95	56.99	65.22	61.42	49.06	46.07	51.06
2033	54.37	56.08	51.20	46.74	42.92	36.07	65.83	71.90	67.67	54.48	48.82	54.15
2034	56.85	59.24	53.97	48.89	44.67	35.17	69.64	76.29	69.28	53.62	51.14	57.27
2035	59.42	61.88	54.02	51.01	41.77	41.47	69.74	78.64	70.53	52.15	47.49	53.02
2036	56.32	59.31	54.32	47.08	44.23	39.10	72.98	82.79	74.35	56.25	49.39	54.82

Combined

2019	35.46	32.07	24.66	20.96	17.80	24.14	44.63	54.75	33.00	25.29	25.37	29.30
2020	27.97	27.10	23.74	18.56	18.62	19.01	39.27	43.17	36.80	23.49	23.16	27.59
2021	27.56	26.40	23.65	20.20	19.29	19.73	41.02	45.65	42.20	24.71	24.30	27.08
2022	27.57	30.29	27.34	25.22	23.19	22.53	40.43	45.30	42.41	29.14	29.82	31.96
2023	32.14	33.01	30.56	30.23	26.21	23.17	39.84	44.86	42.10	32.84	33.14	35.64
2024	36.86	36.70	32.88	31.86	29.37	25.16	43.55	50.97	50.49	38.79	35.22	39.48
2025	40.54	40.95	36.14	34.39	31.29	26.45	46.08	55.51	54.36	39.65	37.32	42.01
2026	44.49	44.35	39.94	38.18	33.41	28.10	49.27	57.96	55.88	41.92	39.58	43.85
2027	46.39	45.98	39.40	35.90	32.92	28.82	47.74	56.91	55.42	43.67	38.92	43.62
2028	46.72	45.87	39.40	35.23	33.06	29.34	49.80	57.61	53.66	42.37	39.14	44.99
2029	48.43	47.93	43.37	39.58	35.08	32.06	53.78	65.15	60.03	45.08	42.32	47.25
2030	52.54	52.48	46.32	41.89	38.98	34.69	61.35	70.98	66.95	51.93	46.83	52.12
2031	57.05	56.63	50.00	43.96	41.25	37.93	64.97	74.01	68.84	52.13	48.62	54.44
2032	58.57	58.53	53.06	49.33	43.32	39.45	68.96	76.58	71.63	55.13	51.85	57.61
2033	61.92	62.12	54.99	49.36	46.46	43.83	76.01	82.13	77.12	60.89	54.69	60.92
2034	65.06	65.46	57.97	52.00	49.07	44.56	79.90	85.97	78.08	60.54	57.53	63.94
2035	68.23	68.70	58.19	53.40	45.81	44.50	78.44	90.71	79.87	59.04	54.21	59.85
2036	65.47	65.84	58.27	51.01	47.57	45.93	83.12	92.20	84.40	63.96	56.22	62.78
2037	-	-	-	-	-	-	-	-	-	-	-	-

Annual Average

	On-Peak	Off-Peak	Combined
2019	$35.42	$24.26	$30.62
2020	$31.45	$21.97	$27.37
2021	$31.78	$24.11	$28.48
2022	$34.65	$26.79	$31.27
2023	$37.14	$29.00	$33.64
2024	$41.70	$32.19	$37.61
2025	$44.75	$34.61	$40.39
2026	$47.62	$37.05	$43.08
2027	$47.34	$37.19	$42.98
2028	$47.38	$37.42	$43.10
2029	$51.21	$40.65	$46.67
2030	$56.38	$44.84	$51.42
2031	$59.32	$47.31	$54.15
2032	$62.29	$49.99	$57.00
2033	$65.91	$54.19	$60.87
2034	$68.62	$56.34	$63.34
2035	$68.43	$56.76	$63.41
2036	$70.13	$57.58	$64.73

Source Offical Market Price Forecast dated December 2018
Blended Market Prices (Blending weights which are used to calculate blended prices are based
on system balancing purchases and sales from GRID run using December 2018 Official Forward Market Price Curve

Table 3
Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs ($/kW-yr)	Simple Cycle CT Fixed Costs ($/kW-yr)	Capitalized Energy Costs ($/kW-yr)	Capitalized Energy Costs 70.5% CF ($/MWh)
	(a)	(b)	(c)	(d)
			((a) - (b))	(c)/(8.760 x 70.5%)
2030	$200.13	$143.51	$56.62	$9.17
2031	$204.39	$146.58	$57.81	$9.36
2032	$208.67	$149.66	$59.01	$9.56
2033	$213.01	$152.77	$60.24	$9.75
2034	$217.41	$155.92	$61.49	$9.96
2035	$221.88	$159.11	$62.77	$10.16
2036	$226.39	$162.36	$64.03	$10.37
2037	$230.95	$165.64	$65.31	$10.58

Columns

(a) Table 9 Column (f)

(b) Table 9 Column (f)

(c) and (d) Capitalized energy costs are zero since fixed cost of CCCT is lower than the fixed cost of SCCT.

Table 4
Total Standard Avoided Energy Cost

Year	Combined Cycle Gas Price ($/MMBtu)	Combined Cycle Energy Cost ($/MWh)	Capitalized Energy Costs 70.5% CF ($/MWh)	Total Standard Avoided Energy Cost ($/MWh)
	(a)	(b)	(c)	(d)
		(a) x 6.790		(b) + (c)
2030	$5.00	$33.95	$9.17	$43.12
2031	$5.32	$36.12	$9.36	$45.48
2032	$5.64	$38.30	$9.56	$47.85
2033	$5.96	$40.47	$9.75	$50.22
2034	$6.27	$42.57	$9.96	$52.53
2035	$5.94	$40.33	$10.16	$50.50
2036	$5.99	$40.67	$10.37	$51.04
2037	$6.34	$43.05	$10.58	$53.62

Columns
(a) Table 10
(b) 6.790 MWh/MMBtu Heat Rate - Table 9
(c) Table 3 Column (d)

Table 5
Total Standard Avoided Cost

Year	Avoided Firm Capacity Costs	Total Standard Avoided Energy Cost	Total Standard Avoided Costs At Stated Capacity Factor		
			75%	85%	90%
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
			(b)+(a) x1000/(8760 x 0.75)	(b)+(a) x1000/(8760 x 0.85)	(b)+(a) x1000/(8760 x 0.9)
2030	$143.51	$43.12	$64.96	$62.39	$61.32
2031	$146.58	$45.48	$67.79	$65.17	$64.08
2032	$149.66	$47.85	$70.63	$67.95	$66.83
2033	$152.77	$50.22	$73.48	$70.74	$69.60
2034	$155.92	$52.53	$76.26	$73.47	$72.31
2035	$159.11	$50.50	$74.71	$71.86	$70.68
2036	$162.36	$51.04	$75.75	$72.84	$71.63
2037	$165.64	$53.62	$78.84	$75.87	$74.63

Columns

(a) Table 3 Column (a) minus Column (c)

(b) Table 4 Column (d)

Table 6
On- & Off- Peak Energy Prices

Year	Avoided Firm Capacity Costs	Capacity Cost Allocated to On-Peak Hours	Total Standard Avoided Energy Cost	On-Peak 4,909 Hours	Off-Peak 3,851 Hours
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
		(a) *1000 / (100.0% x 8760 x 56%		(b) + (c)	(c)
2030	$143.51	$29.23	$43.12	$72.35	$43.12
2031	$146.58	$29.86	$45.48	$75.34	$45.48
2032	$149.66	$30.48	$47.85	$78.34	$47.85
2033	$152.77	$31.12	$50.22	$81.34	$50.22
2034	$155.92	$31.76	$52.53	$84.29	$52.53
2035	$159.11	$32.41	$50.50	$82.91	$50.50
2036	$162.36	$33.07	$51.04	$84.11	$51.04
2037	$165.64	$33.74	$53.62	$87.36	$53.62

Columns

- (a) Table 3 Column (a) minus Column (c)
- (b) Table 9 100.0% is the on-peak capacity factor of the Proxy CCCT Resource
- (d) 56% is the percent of all hours that are on-peak
- (c) Table 4 Column (d)

Table 3 (Renewable)
Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs	Simple Cycle CT Fixed Costs	Capitalized Energy Costs	Capitalized Energy Costs 70.5% CF
	($/kW-yr)	($/kW-yr)	($/kW-yr)	($/MWh)
	(a)	(b)	(c)	(d)
			((a) - (b))	(c)/(8.760 x 70.5%)
2018	$151.52	$108.67	$42.85	$6.94
2019	$155.00	$111.16	$43.84	$7.10
2020	$159.12	$114.11	$45.01	$7.29
2021	$163.31	$117.10	$46.21	$7.48
2022	$167.42	$120.05	$47.37	$7.67
2023	$171.42	$122.90	$48.52	$7.86
2024	$175.43	$125.77	$49.66	$8.04
2025	$179.49	$128.69	$50.80	$8.23
2026	$183.58	$131.62	$51.96	$8.41
2027	$187.62	$134.52	$53.10	$8.60
2028	$191.68	$137.44	$54.24	$8.78
2029	$195.88	$140.44	$55.44	$8.98
2030	$200.13	$143.51	$56.62	$9.17
2031	$204.39	$146.58	$57.81	$9.36
2032	$208.67	$149.66	$59.01	$9.56
2033	$213.01	$152.77	$60.24	$9.75
2034	$217.41	$155.92	$61.49	$9.96
2035	$221.88	$159.11	$62.77	$10.16
2036	$226.39	$162.36	$64.03	$10.37

Columns
(a) Table 9 Column (f)
(b) Table 9 Column (f)
(c) and (d) Capitalized energy costs are zero since fixed cost of CCCT is lower than the fixed cost of SCCT.

Table 4 (Renewable)
Avoided Capacity Costs

Year	Avoided Firm Capacity Costs
	($/kW-yr)
	(a)
2018	$108.67
2019	$111.16
2020	$114.11
2021	$117.10
2022	$120.05
2023	$122.90
2024	$125.77
2025	$128.69
2026	$131.62
2027	$134.52
2028	$137.44
2029	$140.44
2030	$143.51
2031	$146.58
2032	$149.66
2033	$152.77
2034	$155.92
2035	$159.11
2036	$162.36

Columns
(a) Table 3 (Renewable) Column (a) minus Column (c)

Table 7
Comparison between Proposed and Current Standard Fixed Avoided Costs
$/MWh

Year	Staff Standard Base Load QF	Current Standard Base Load QF	Difference Standard Base Load QF	Staff Standard Wind QF (2)	Current Standard Wind QF (2)	Difference Standard Wind QF (2)	Staff Standard Fixed Solar QF	Current Standard Fixed Solar QF	Difference Standard Fixed Solar QF	Staff Standard Tracking Solar QF	Current Standard Tracking Solar QF	Difference Standard Tracking Solar QF
2019	$30.51	$21.70	$8.82	$30.13	$21.23	$8.91	$33.00	$22.92	$10.08	$32.93	$22.88	$10.05
2020	$27.28	$24.23	$3.05	$26.86	$23.73	$3.13	$29.29	$25.31	$3.98	$29.23	$25.27	$3.96
2021	$28.41	$27.50	$0.91	$27.94	$26.98	$0.96	$29.89	$28.63	$1.26	$29.84	$28.59	$1.25
2022	$31.19	$29.22	$1.98	$30.72	$28.69	$2.03	$32.71	$30.38	$2.32	$32.66	$30.34	$2.32
2023	$33.56	$30.89	$2.68	$33.07	$30.33	$2.74	$35.13	$31.96	$3.17	$35.08	$31.92	$3.16
2024	$37.52	$33.24	$4.28	$37.04	$32.66	$4.38	$39.46	$34.29	$5.16	$39.39	$34.25	$5.14
2025	$40.29	$36.06	$4.23	$39.81	$35.47	$4.35	$42.39	$37.10	$5.28	$42.32	$37.06	$5.26
2026	$42.97	$37.30	$5.68	$42.49	$36.68	$5.81	$45.17	$38.30	$6.87	$45.10	$38.25	$6.84
2027	$42.88	$38.48	$4.40	$42.37	$37.85	$4.52	$44.93	$39.48	$5.45	$44.87	$39.44	$5.43
2028	$43.00	$40.40	$2.61	$42.47	$39.73	$2.73	$44.98	$41.28	$3.70	$44.92	$41.24	$3.67
2029	$46.57	$44.11	$2.46	$46.02	$43.43	$2.59	$48.70	$45.06	$3.64	$48.63	$45.02	$3.61
2030	$59.50	$60.37	($0.87)	$47.43	$48.29	($0.87)	$77.73	$78.51	($0.78)	$79.19	$79.96	($0.78)
2031	$62.22	$60.89	$1.32	$49.88	$48.56	$1.32	$80.84	$79.43	$1.41	$82.32	$80.90	$1.42
2032	$64.94	$63.98	$0.95	$52.34	$51.39	$0.95	$83.94	$82.90	$1.04	$85.46	$84.41	$1.05
2033	$67.66	$66.51	$1.15	$54.80	$53.65	$1.15	$87.06	$85.82	$1.25	$88.61	$87.36	$1.26
2034	$70.33	$66.41	$3.92	$57.20	$53.29	$3.91	$90.13	$86.12	$4.02	$91.71	$87.69	$4.02
2035	$68.66	$67.99	$0.67	$55.26	$54.59	$0.67	$88.87	$88.10	$0.77	$90.48	$89.70	$0.78
2036	$69.57	$68.29	$1.29	$55.90	$54.62	$1.28	$90.19	$88.80	$1.39	$91.84	$90.44	$1.40

15 Year (2019 - 2033) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$40.40	$37.14	$3.26	$37.80	$34.47	$3.33	$45.33	$41.35	$3.99	$45.55	$41.58	$3.97

Notes: (1) Discount Rate - 2017 IRP Discount Rate
(2) Avoided cost prices have been reduced by a wind and solar integration charges for QFs located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .
If the QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charges

15 Year (2020 - 2034) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$42.68	$40.00	$2.68	$39.42	$36.67	$2.74	$48.47	$45.15	$3.32	$48.77	$45.46	$3.31

15 Year (2021 - 2035) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$45.40	$42.84	$2.55	$41.42	$38.80	$2.62	$52.19	$49.04	$3.15	$52.58	$49.44	$3.14

Table 8

Comparison between Proposed and Current Renewable Standard Fixed Avoided Costs

$/MWh

Year	Staff Renewable Standard Base Load QF	Current Renewable Standard Base Load QF	Difference Renewable Standard Base Load QF	Staff Renewable Standard Wind QF (2)	Current Renewable Standard Wind QF (2)	Difference Renewable Standard Wind QF (2)	Staff Renewable Standard Fixed Solar QF	Current Renewable Standard Fixed Solar QF	Difference Renewable Standard Fixed Solar QF	Staff Renewable Standard Tracking Solar QF	Current Renewable Standard Tracking Solar QF	Difference Renewable Standard Tracking Solar QF
2019	$30.51	$21.70	$8.82	$30.13	$21.23	$8.91	$33.00	$22.92	$10.08	$32.93	$22.88	$10.05
2020	$27.28	$24.23	$3.05	$26.86	$23.73	$3.13	$29.29	$25.31	$3.98	$29.23	$25.27	$3.96
2021	$29.05	$40.24	($11.19)	$15.87	$27.11	($11.24)	$39.28	$50.61	($11.33)	$41.57	$52.89	($11.31)
2022	$29.78	$41.26	($11.48)	$16.26	$27.79	($11.53)	$40.08	$51.81	($11.73)	$42.43	$54.14	($11.71)
2023	$30.50	$42.25	($11.75)	$16.65	$28.46	($11.80)	$40.88	$52.95	($12.07)	$43.29	$55.34	($12.05)
2024	$31.21	$43.22	($12.02)	$17.03	$29.09	($12.05)	$41.84	$53.98	($12.14)	$44.31	$56.43	($12.13)
2025	$31.93	$44.24	($12.32)	$17.42	$29.76	($12.34)	$42.77	$55.09	($12.33)	$45.29	$57.61	($12.31)
2026	$32.64	$45.25	($12.60)	$17.81	$30.43	($12.62)	$43.68	$56.28	($12.60)	$46.26	$58.85	($12.59)
2027	$33.38	$46.26	($12.88)	$18.21	$31.11	($12.90)	$44.61	$57.51	($12.90)	$47.25	$60.14	($12.89)
2028	$34.12	$47.28	($13.16)	$18.62	$31.79	($13.18)	$45.57	$58.70	($13.13)	$48.27	$61.39	($13.12)
2029	$34.86	$48.31	($13.46)	$19.01	$32.48	($13.47)	$46.55	$59.88	($13.34)	$49.31	$62.63	($13.33)
2030	$35.62	$49.36	($13.74)	$19.42	$33.17	($13.75)	$47.54	$61.15	($13.61)	$50.36	$63.96	($13.60)
2031	$36.36	$50.41	($14.05)	$19.81	$33.88	($14.07)	$48.50	$62.40	($13.91)	$51.38	$65.27	($13.90)
2032	$37.15	$51.47	($14.32)	$20.24	$34.59	($14.34)	$49.49	$63.68	($14.19)	$52.43	$66.61	($14.18)
2033	$37.92	$52.54	($14.62)	$20.66	$35.30	($14.64)	$50.47	$64.96	($14.48)	$53.48	$67.95	($14.47)
2034	$38.71	$53.63	($14.93)	$21.09	$36.04	($14.95)	$51.51	$66.31	($14.80)	$54.58	$69.36	($14.78)
2035	$39.50	$54.73	($15.24)	$21.52	$36.77	($15.25)	$52.63	$67.62	($14.99)	$55.76	$70.74	($14.98)
2036	$40.30	$55.84	($15.54)	$21.96	$37.51	($15.55)	$53.71	$68.96	($15.24)	$56.91	$72.14	($15.23)

15 Year (2019 - 2033) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$31.99	$40.93	($8.94)	$19.98	$28.92	($8.95)	$41.34	$50.10	($8.76)	$43.41	$52.16	($8.75)

Notes: (1) Discount Rate - 2017 IRP Discount Rate

(2) Avoided cost prices have been reduced by a wind and solar integration charges for QFs located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .

If the QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charges

15 Year (2020 - 2034) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$32.42	$43.54	($11.12)	$18.91	$30.05	($11.14)	$42.66	$53.72	($11.06)	$45.00	$56.05	($11.05)

15 Year (2021 - 2035) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$33.27	$46.10	($12.83)	$18.15	$31.01	($12.86)	$44.52	$57.38	($12.86)	$47.16	$60.00	($12.84)

Table 7
Comparison between Proposed and Current Standard Fixed Avoided Costs
$/MWh

Year	PAC Standard Base Load QF	Staff Standard Base Load QF	Difference Standard Base Load QF	PAC Standard Wind QF (2)	Staff Standard Wind QF (2)	Difference Standard Wind QF (2)	PAC Standard Fixed Solar QF	Staff Standard Fixed Solar QF	Difference Standard Fixed Solar QF	PAC Standard Tracking Solar QF	Staff Standard Tracking Solar QF	Difference Standard Tracking Solar QF
2019	$30.51	$30.51	$0.00	$30.13	$30.13	$0.00	$33.00	$33.00	$0.00	$32.93	$32.93	$0.00
2020	$27.28	$27.28	$0.00	$26.86	$26.86	$0.00	$29.29	$29.29	$0.00	$29.23	$29.23	$0.00
2021	$28.41	$28.41	$0.00	$21.78	$27.94	($6.16)	$27.83	$29.89	($2.06)	$27.76	$29.84	($2.08)
2022	$31.19	$31.19	$0.00	$22.28	$30.72	($8.44)	$28.18	$32.71	($4.53)	$28.12	$32.66	($4.53)
2023	$33.56	$33.56	$0.00	$22.80	$33.07	($10.27)	$28.61	$35.13	($6.52)	$28.56	$35.08	($6.52)
2024	$37.52	$37.52	$0.00	$23.34	$37.04	($13.69)	$29.30	$39.46	($10.16)	$29.24	$39.39	($10.15)
2025	$40.29	$40.29	$0.00	$23.86	$39.81	($15.95)	$29.90	$42.39	($12.48)	$29.85	$42.32	($12.47)
2026	$42.97	$42.97	$0.00	$24.38	$42.49	($18.11)	$30.47	$45.17	($14.70)	$30.42	$45.10	($14.68)
2027	$42.88	$42.88	$0.00	$24.92	$42.37	($17.45)	$31.08	$44.93	($13.86)	$31.02	$44.87	($13.84)
2028	$43.00	$43.00	$0.00	$25.49	$42.47	($16.97)	$31.76	$44.98	($13.22)	$31.71	$44.92	($13.21)
2029	$46.57	$46.57	$0.00	$26.07	$46.02	($19.96)	$32.47	$48.70	($16.23)	$32.41	$48.63	($16.22)
2030	$60.56	$59.50	$1.06	$26.66	$47.43	($20.77)	$33.17	$77.73	($44.56)	$33.11	$79.19	($46.07)
2031	$63.34	$62.22	$1.13	$27.25	$49.88	($22.64)	$33.85	$80.84	($46.99)	$33.79	$82.32	($48.53)
2032	$66.14	$64.94	$1.21	$27.89	$52.34	($24.45)	$34.58	$83.94	($49.37)	$34.52	$85.46	($50.94)
2033	$68.93	$67.66	$1.27	$28.50	$54.80	($26.30)	$35.28	$87.06	($51.79)	$35.22	$88.61	($53.39)
2034	$71.66	$70.33	$1.33	$29.14	$57.20	($28.06)	$36.05	$90.13	($54.08)	$35.99	$91.71	($55.72)
2035	$70.06	$68.66	$1.40	$29.78	$55.26	($25.48)	$36.94	$88.87	($51.93)	$36.88	$90.48	($53.60)
2036	$71.05	$69.57	$1.48	$30.44	$55.90	($25.46)	$37.76	$90.19	($52.43)	$37.70	$91.84	($54.13)

15 Year (2019 - 2033) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$40.61	$40.40	$0.21	$25.30	$37.80	($12.50)	$30.79	$45.33	($14.55)	$30.73	$45.55	($14.82)

Notes: (1) Discount Rate - 2017 IRP Discount Rate
(2) Avoided cost prices have been reduced by a wind and solar integration charges for QFs located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .
If the QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charges

15 Year (2020 - 2034) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$42.95	$42.68	$0.27	$24.93	$39.42	($14.49)	$30.75	$48.47	($17.72)	$30.70	$48.77	($18.08)

15 Year (2021 - 2035) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$45.75	$45.40	$0.35	$24.91	$41.42	($16.51)	$31.16	$52.19	($21.02)	$31.11	$52.58	($21.47)

Table 8

Comparison between Proposed and Current Renewable Standard Fixed Avoided Costs

$/MWh

Year	PAC Renewable Standard Base Load QF	Staff Renewable Standard Base Load QF	Difference Renewable Standard Base Load QF	PAC Renewable Standard Wind QF (2)	Staff Renewable Standard Wind QF (2)	Difference Renewable Standard Wind QF (2)	PAC Renewable Standard Fixed Solar QF	Staff Renewable Standard Fixed Solar QF	Difference Renewable Standard Fixed Solar QF	PAC Renewable Standard Tracking Solar QF	Staff Renewable Standard Tracking Solar QF	Difference Renewable Standard Tracking Solar QF
2019	$30.51	$30.51	$0.00	$30.13	$30.13	$0.00	$33.00	$33.00	$0.00	$32.93	$32.93	$0.00
2020	$27.28	$27.28	$0.00	$26.86	$26.86	$0.00	$29.29	$29.29	$0.00	$29.23	$29.23	$0.00
2021	$30.51	$29.05	$1.46	$23.88	$15.87	$8.00	$29.93	$39.28	($9.36)	$29.86	$41.57	($11.71)
2022	$33.34	$29.78	$3.57	$24.43	$16.26	$8.16	$30.33	$40.08	($9.74)	$30.27	$42.43	($12.15)
2023	$35.76	$30.50	$5.26	$25.00	$16.65	$8.35	$30.81	$40.88	($10.07)	$30.76	$43.29	($12.53)
2024	$39.77	$31.21	$8.56	$25.59	$17.03	$8.56	$31.55	$41.84	($10.29)	$31.49	$44.31	($12.81)
2025	$42.59	$31.93	$10.67	$26.16	$17.42	$8.74	$32.20	$42.77	($10.57)	$32.15	$45.29	($13.15)
2026	$45.32	$32.64	$12.68	$26.73	$17.81	$8.91	$32.82	$43.68	($10.86)	$32.77	$46.26	($13.50)
2027	$45.28	$33.38	$11.90	$27.32	$18.21	$9.11	$33.48	$44.61	($11.13)	$33.42	$47.25	($13.83)
2028	$45.46	$34.12	$11.34	$27.95	$18.62	$9.34	$34.22	$45.57	($11.35)	$34.17	$48.27	($14.10)
2029	$49.09	$34.86	$14.23	$28.59	$19.01	$9.58	$34.99	$46.55	($11.56)	$34.93	$49.31	($14.38)
2030	$63.14	$35.62	$27.52	$29.24	$19.42	$9.82	$35.75	$47.54	($11.79)	$35.69	$50.36	($14.66)
2031	$65.98	$36.36	$29.62	$29.89	$19.81	$10.07	$36.49	$48.50	($12.01)	$36.43	$51.38	($14.94)
2032	$68.84	$37.15	$31.70	$30.59	$20.24	$10.35	$37.28	$49.49	($12.21)	$37.22	$52.43	($15.21)
2033	$71.69	$37.92	$33.77	$31.26	$20.66	$10.61	$38.04	$50.47	($12.43)	$37.98	$53.48	($15.50)
2034	$74.48	$38.71	$35.77	$31.96	$21.09	$10.87	$38.87	$51.51	($12.64)	$38.81	$54.58	($15.77)
2035	$72.94	$39.50	$33.44	$32.66	$21.52	$11.14	$39.82	$52.63	($12.81)	$39.76	$55.76	($16.00)
2036	$73.99	$40.30	$33.69	$33.38	$21.96	$11.42	$40.70	$53.71	($13.01)	$40.64	$56.91	($16.26)

15 Year (2019 - 2033) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$42.50	$31.99	$10.51	$27.20	$19.98	$7.22	$32.68	$41.34	($8.66)	$32.63	$43.41	($10.78)

Notes: (1) Discount Rate - 2017 IRP Discount Rate

(2) Avoided cost prices have been reduced by a wind and solar integration charges for QFs located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .

If the QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charges

15 Year (2020 - 2034) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$45.09	$32.42	$12.67	$27.07	$18.91	$8.16	$32.90	$42.66	($9.77)	$32.84	$45.00	($12.16)

15 Year (2021 - 2035) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$48.15	$33.27	$14.89	$27.32	$18.15	$9.17	$33.57	$44.52	($10.95)	$33.51	$47.16	($13.64)

Table 9
Total Cost of Displaceable Resources

Year	Estimated Capital Cost $/kW (a)	Capital Cost at Real Levelized Rate $/kW-yr (b)	Fixed O&M $/kW-yr (c)	Variable O&M $/MWh (d)	Total O&M at Expected CF $/kW-yr (e)	Total Resource Fixed Costs $/kW-yr (f)
194 MW - SCCT Frame "F" x1 - East Side Resource (5,050')						
2018	$843	$58.66	$30.90	$6.61	$50.01	$108.67
2019		$60.01	$31.61	$6.76	$51.15	$111.16
2020		$61.60	$32.45	$6.94	$52.51	$114.11
2021		$63.22	$33.30	$7.12	$53.88	$117.10
2022		$64.81	$34.14	$7.30	$55.24	$120.05
2023		$66.36	$34.95	$7.47	$56.54	$122.90
2024		$67.91	$35.77	$7.64	$57.86	$125.77
2025		$69.48	$36.60	$7.82	$59.21	$128.69
2026		$71.06	$37.43	$8.00	$60.56	$131.62
2027		$72.62	$38.25	$8.18	$61.90	$134.52
2028		$74.19	$39.08	$8.36	$63.25	$137.44
2029		$75.81	$39.94	$8.54	$64.63	$140.44
2030		$77.46	$40.81	$8.73	$66.05	$143.51
2031		$79.11	$41.68	$8.92	$67.47	$146.58
2032		$80.77	$42.55	$9.11	$68.89	$149.66
2033		$82.45	$43.44	$9.30	$70.32	$152.77
2034		$84.15	$44.34	$9.49	$71.77	$155.92
2035		$85.88	$45.25	$9.68	$73.23	$159.11
2036		$87.63	$46.17	$9.88	$74.73	$162.36
2037		$89.40	$47.10	$10.08	$76.24	$165.64

Source: (a)(c)(d) Plant Costs - 2019 IRP - Table 6.1 & 6.2
(b) = (a) x Payment Factor
(e) = (d) x (8.76 x 33%) + (c)
(f) = (b) + (e)

		194 MW - SCCT Frame "F" x1 - East Side Resource (5,050')	
	194	MW Plant capacity	MW
2018 $	$843	Plant capacity cost	$/kW
2018 $	$15.97	Fixed O&M & Capitalized O&M	$/kW-yr
2018 $	$14.93	Fixed Pipeline	$/kW-yr
2018 $	$30.90	Fixed O&M Including Fixed Pipeline & Capitalized (	$/kW-yr
2018 $	$6.61	Variable O&M and Other Costs	$/MWH
	6.959%	Payment Factor	
	33%	Capacity Factor	

Table 9
Total Cost of Displaceable Resources

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Variable O&M $/MWh	Total O&M at Expected CF $/kW-yr	Total Resource Fixed Costs $/kW-yr	Fuel Cost $/MMBtu	IRP Resource Energy Cost $/MWh	Total Avoided Costs $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
447 MW - CCCT Dry "G/H", 1x1 - West Side Resource (1,500')									
2018	$1,429	$97.03	$43.19	$1.83	$54.49	$151.52			
2019		$99.26	$44.18	$1.87	$55.74	$155.00			
2020		$101.90	$45.35	$1.92	$57.22	$159.12			
2021		$104.58	$46.54	$1.97	$58.73	$163.31			
2022		$107.21	$47.71	$2.02	$60.21	$167.42			
2023		$109.77	$48.85	$2.07	$61.65	$171.42			
2024		$112.34	$49.99	$2.12	$63.09	$175.43			
2025		$114.94	$51.15	$2.17	$64.55	$179.49			
2026		$117.56	$52.31	$2.22	$66.02	$183.58			
2027		$120.15	$53.46	$2.27	$67.47	$187.62			
2028		$122.75	$54.62	$2.32	$68.93	$191.68			
2029		$125.44	$55.82	$2.37	$70.44	$195.88			
2030		$128.16	$57.03	$2.42	$71.97	$200.13	$5.00	$33.95	$66.36
2031		$130.89	$58.24	$2.47	$73.50	$204.39	$5.32	$36.12	$69.22
2032		$133.63	$59.46	$2.52	$75.04	$208.67	$5.64	$38.30	$72.09
2033		$136.41	$60.70	$2.57	$76.60	$213.01	$5.96	$40.47	$74.96
2034		$139.23	$61.95	$2.62	$78.18	$217.41	$6.27	$42.57	$77.77
2035		$142.09	$63.22	$2.67	$79.79	$221.88	$5.94	$40.33	$76.26
2036		$144.98	$64.51	$2.72	$81.41	$226.39	$5.99	$40.67	$77.33
2037		$147.90	$65.81	$2.77	$83.05	$230.95	$6.34	$43.05	$80.45

Table 9
Total Cost of Displaceable Resources

Sources, Inputs and Assumptions

Source: (a)(c)(d) Plant Costs - 2019 IRP - Table 6.1 & 6.2
(b) = (a) x 0.0679
(e) = (d) x (8.76 x 70.5%) + (c)
(f) = (b) + (e)
(g) Gas Price Forecast
(h) = 6790 x (g) / 1000
(i) = (f) / (8.76 x 'Capacity Factor') + (h)

447 MW - CCCT Dry "G/H", 1x1 - West Side Resource (1,500')

CCCT Statistics	MW	Percent	Cap Cost	Fixed
CCCT (Dry "G/H" 1x1)	396	88.6%	$1,552	$45.05
CCCT Duct Firing (Dry "G/H" 1x1)	51	11.4%	$478	$28.76
Capacity Weighted	447	100.0%	$1,429	$43.19

CCCT Statistics	MW	CF	aMW	Percent	Variable	Heat Rate
CCCT (Dry "G/H" 1x1)	396	78.0%	309	98.1%	$1.86	6,788
CCCT Duct Firing (Dry "G/H" 1x1)	51	12.0%	6	1.9%	0.15	6,788
Energy Weighted	447	70.5%	315	100.0%	$1.83	6,790
						Rounded

	CCCT	Duct Firing	Plant Costs - 2019 IRP - Table 6.1 & 6.2
	396	51	MW Plant capacity
2018 $	$1,552	$478	Plant capacity cost
2018 $	$21.68	$5.39	Fixed O&M & Capitalized O&M
2018 $	$23.37	$23.37	Fixed Pipeline
	$45.05	$28.76	Fixed O&M Including Fixed Pipeline & Capitalized O&M ($/kW-Yr)
	$1.86	$0.15	Variable O&M and Other Costs
	6,788	6,788	Heat Rate in btu/kWh
	6.790%	6.790%	Payment Factor
	78.0%	12.0%	Capacity Factor
		70.5%	Energy Weighted Capacity Factor
		100.0%	Capacity Factor - On-peak 70.5% / 56.0% (percent of hours on-peak)

Company Official Inflation Forecast - Dated March 2018

2017	1.8%	2023	2.4%	2029	2.2%	2035	2.1%
2018	2.0%	2024	2.3%	2030	2.2%	2036	2.0%
2019	2.3%	2025	2.3%	2031	2.1%	2037	2.0%
2020	2.7%	2026	2.3%	2032	2.1%	2038	2.0%
2021	2.6%	2027	2.2%	2033	2.1%	2039	0.0%
2022	2.5%	2028	2.2%	2034	2.1%	2040	0.0%

Table 10
Gas Price Forecast
$/MMBtu

Year	Burner tip West Side Gas Fuel Cost
2030	$5.00
2031	$5.32
2032	$5.64
2033	$5.96
2034	$6.27
2035	$5.94
2036	$5.99

Source
Offical Market Price Forecast dated December 2018

Table 11
Integration Cost

Year	Wind Integration Cost $/MWh	Solar Integration Cost $/MWh
2016	$0.57	$0.60
2017	$0.58	$0.62
2018	$0.59	$0.63
2019	$0.60	$0.64
2020	$0.61	$0.65
2021	$0.62	$0.67
2022	$0.63	$0.69
2023	$0.65	$0.71
2024	$0.67	$0.73
2025	$0.68	$0.75
2026	$0.69	$0.77
2027	$0.71	$0.79
2028	$0.73	$0.81
2029	$0.75	$0.83
2030	$0.77	$0.85
2031	$0.79	$0.87
2032	$0.81	$0.89
2033	$0.83	$0.91
2034	$0.85	$0.93
2035	$0.87	$0.95
2036	$0.89	$0.97
2037	$0.91	$0.99

Note: 2017 IRP Volume II-Appendix F

Company Official Inflation Forecast Dated December 31, 2018

2017	2.0%	2023	2.4%	2029	2.3%	2035	2.2%
2018	2.3%	2024	2.4%	2030	2.3%	2036	2.2%
2019	2.2%	2025	2.2%	2031	2.3%	2037	2.2%
2020	2.3%	2026	2.2%	2032	2.3%	2038	2.2%
2021	2.4%	2027	2.2%	2033	2.2%	2039	2.2%
2022	2.4%	2028	2.3%	2034	2.2%	2040	2.2%

Table 12
2019 IRP Wyoming Wind Resource
44% Capacity Factor

Year	Estimated Capital Cost $/kW	Fixed Capital Cost at Real Levelized $/kW-yr	Fixed O&M $/kW-yr	Fixed Costs $/MWh	Variable O&M $/MWh	Tax Credit $/MWh	Avoided Cost $/MWh	Wind Integration Cost $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2019 IRP Wyoming Wind Resource - 44% Capacity Factor								
2016								
2017								
2018	$1,301	$89.76	$27.99	$30.83	$0.65	($15.55)	$15.93	$0.59
2019		$91.82	$28.63	$31.54	$0.66	($15.91)	$16.29	$0.60
2020		$94.26	$29.39	$32.37	$0.68	($16.33)	$16.72	$0.61
2021		$96.74	$30.16	$33.23	$0.70	($16.76)	$17.17	$0.62
2022		$99.18	$30.92	$34.06	$0.72	($17.18)	$17.60	$0.63
2023		$101.55	$31.66	$34.88	$0.74	($17.59)	$18.03	$0.65
2024		$103.92	$32.40	$35.69	$0.76	($18.00)	$18.45	$0.67
2025		$106.32	$33.15	$36.52	$0.78	($18.42)	$18.88	$0.68
2026		$108.74	$33.90	$37.35	$0.80	($18.84)	$19.31	$0.69
2027		$111.13	$34.65	$38.17	$0.82	($19.25)	$19.74	$0.71
2028		$113.54	$35.40	$39.00	$0.84	($19.67)	$20.17	$0.73
2029		$116.02	$36.17	$39.85	$0.86	($20.10)	$20.61	$0.75
2030		$118.54	$36.96	$40.71	$0.88	($20.54)	$21.05	$0.77
2031		$121.06	$37.75	$41.58	$0.90	($20.98)	$21.50	$0.79
2032		$123.59	$38.54	$42.45	$0.92	($21.42)	$21.95	$0.81
2033		$126.16	$39.34	$43.33	$0.94	($21.87)	$22.40	$0.83
2034		$128.77	$40.15	$44.23	$0.96	($22.32)	$22.87	$0.85
2035		$131.42	$40.97	$45.14	$0.98	($22.78)	$23.34	$0.87
2036		$134.09	$41.80	$46.05	$1.00	($23.24)	$23.81	$0.89
2037		$136.79	$42.64	$46.98	$1.02	($23.71)	$24.29	$0.91

Sources, Inputs and Assumptions

Source:	(c)(f)	Plant Costs 2017 IRP (Table 6.2) in $2016
	(a)	Plant capacity cost
	(b)	= (a) x 0.06899
	(d)	= ((b) + (c)) / (8.76 x 43.6%)
	(g)	= (d) + (f)
	(h)	2017 IRP Volume II-Appendix F

2019 IRP Wyoming Wind Resource - 44% Capacity Factor

	Wind	Cost and Input Assumptions	
2018 $	$1,301	Plant capacity cost	$/kW-yr
2018 $	$27.99	Fixed O&M, plus on-going capital cost	$/kW-yr
2018 $	0.57	Integration Cost	
2018 $	$0.65	Variable O&M	$/MWH
2018 $	($15.55)	Tax Credit $/MWh	$/MWH
	15.8%	East Wind Capacity Contribution	
	6.899%	Payment Factor	
	43.6%	Capacity Factor	

Company Official Inflation Forecast - Dated March 2018

2017	1.8%	2023	2.4%	2029	2.2%	2035	2.1%	
2018	2.0%	2024	2.3%	2030	2.2%	2036	2.0%	
2019	2.3%	2025	2.3%	2031	2.1%	2037	2.0%	
2020	2.7%	2026	2.3%	2032	2.1%	2038	2.0%	
2021	2.6%	2027	2.2%	2033	2.1%	2039	2.0%	Company Official Inflatio
2022	2.5%	2028	2.2%	2034	2.1%	2040	2.0%	

Table 13
2019 IRP Wind Resource Costs
Adjusted to On-Peak / Off-Peak Prices

	Renewable Avoided Resource Cost	On-Peak / Off-Peak Factors		On-Peak Renewable Avoided Resource Cost	Off-Peak Renewable Avoided Resource Cost
Year	$/MWH	On-Peak	Off-Peak	On-Peak	Off-Peak
	(a)	(b)	(c)	(d)	(e)
				(a) x (b)	(a) x (c)
2019	$16.29	1.1681	0.7840	$19.02	$12.77
2020	$16.72	1.1721	0.7810	$19.60	$13.06
2021	$17.17	1.1571	0.8004	$19.86	$13.74
2022	$17.60	1.1396	0.8223	$20.06	$14.48
2023	$18.03	1.1254	0.8414	$20.29	$15.17
2024	$18.45	1.1260	0.8392	$20.78	$15.48
2025	$18.88	1.1239	0.8421	$21.21	$15.90
2026	$19.31	1.1192	0.8474	$21.61	$16.36
2027	$19.74	1.1161	0.8518	$22.03	$16.81
2028	$20.17	1.1145	0.8547	$22.48	$17.24
2029	$20.61	1.1139	0.8550	$22.95	$17.62
2030	$21.05	1.1117	0.8575	$23.41	$18.05
2031	$21.50	1.1085	0.8600	$23.83	$18.49
2032	$21.95	1.1060	0.8647	$24.28	$18.98
2033	$22.40	1.1031	0.8686	$24.71	$19.46
2034	$22.87	1.1027	0.8700	$25.21	$19.89
2035	$23.34	1.1069	0.8637	$25.83	$20.15
2036	$23.81	1.1076	0.8626	$26.37	$20.54

Columns

(a) Table 12 Column (g)

(b) Ratio blended market On-Peak to annual prices

(c) Ratio blended market Off-Peak to annual prices

Appendix 1

PACIFIC POWER
AVOIDED COST CALCULATION-PACIFICORP PROPOSAL

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – MARCH 2019

15 Year (2019 - 2033) Nominal levelized Price at 6.920% Discount Rate

Non-renewable	PacifiCorp	Current	Difference
Baseload	$40.61	$37.14	$3.46
Wind	$25.30	$34.47	($9.17)
Fixed Solar	$30.79	$41.35	($10.56)
Tracking Solar	$30.73	$41.58	($10.85)

Renewable	PacifiCorp	Current	Difference
Baseload	$42.50	$40.93	$1.57
Wind	$27.20	$28.92	($1.72)
Fixed Solar	$32.68	$50.10	($17.42)
Tracking Solar	$32.63	$52.16	($19.54)

PacifiCorp Illustrative Updates

1 Renewable rate less non-renewable rate equals RPS Compliance Cost (July 12, 2018 value of $1.92/MV

2 Wind and solar costs and characteristics from 2019 IRP - applied to wind and solar only

3 Changes to payment factors, discount rates, resource-specific cost de-escalation for renewable resources

Note: unlike Staff's proposal, each of the prior Schedule 37 updates have included inflation forecasts co

Vh (2017$)) during renewable sufficiency period starting 2021.

s, and inflation.
nsistent with the forward market prices in the filing.

Exhibit 1
Standard Avoided Cost Prices for Base Load QF (1)
$/MWH

	Standard Avoided Resource		Base Load QF Resource				
Year	Avoided Firm Capacity Costs	Energy Only Price	Capacity Contribution	QF Capacity Adder	Capacity Adder Allocated to On-Peak Hours	On-Peak	Off-Peak
	$/kW-yr	$/MWh		($/kW-yr)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				= (a) * (c)	(d) *1000 / (100.0% x 8760 x 56%)	(e) + (b)	= (b)
2019	Market Based Prices 2019 through 2029					$35.42	$24.26
2020						$31.45	$21.97
2021						$31.78	$24.11
2022						$34.65	$26.79
2023						$37.14	$29.00
2024						$41.70	$32.19
2025						$44.75	$34.61
2026						$47.62	$37.05
2027						$47.34	$37.19
2028						$47.38	$37.42
2029						$51.21	$40.65
2030	$117.65	$47.13	100.0%	117.65	$23.96	$71.09	$47.13
2031	$120.35	$49.61	100.0%	120.35	$24.51	$74.12	$49.61
2032	$123.11	$52.09	100.0%	123.11	$25.08	$77.17	$52.09
2033	$125.81	$54.57	100.0%	125.81	$25.63	$80.19	$54.57
2034	$128.57	$56.98	100.0%	128.57	$26.19	$83.17	$56.98
2035	$131.40	$55.06	100.0%	131.40	$26.77	$81.82	$55.06
2036	$134.29	$55.72	100.0%	134.29	$27.35	$83.08	$55.72

(1) Capacity Contribution of the Avoided Proxy and Base Load QF resources are assumed to be 100%.

Columns

- (a) Full fixed cost of a proxy CCCT less capitalized energy
- (b) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (e) 100.0% is the on-peak capacity factor of the Base Load QF resource
  56% is the percent of all hours that are on-peak
- (f) 2019-2029 On-Peak Blended Market Prices for QF resource
- (g) 2019-2029 Off-Peak Blended Market Prices for QF resource

Exhibit 2
Standard Avoided Cost Prices for Wind QF (1,2)
$/MWH

Year	Standard Avoided Resource: Avoided Firm On-Peak ($/MWh)	Standard Avoided Resource: Off-Peak ($/MWh)	RPS Cost Adjustment ($/MWh)	Wind QF Resource: On-Peak $/MWh	Wind QF Resource: Off-Peak $/MWh
	(a)	(b)	(c)	(d) = (a)- (c)	(e) = (b)- (c)
2019	Market Based Prices			$34.82	$23.66
2020	2019 through 2020 less Wind Integration (2)			$30.84	$21.36
2021	$27.43	$18.97	$2.10	$25.33	$16.87
2022	$27.66	$19.96	$2.15	$25.51	$17.81
2023	$27.97	$20.91	$2.20	$25.77	$18.71
2024	$28.66	$21.36	$2.25	$26.41	$19.11
2025	$29.24	$21.91	$2.30	$26.94	$19.61
2026	$29.76	$22.54	$2.35	$27.41	$20.19
2027	$30.34	$23.15	$2.40	$27.94	$20.75
2028	$30.99	$23.76	$2.46	$28.53	$21.30
2029	$31.68	$24.32	$2.52	$29.16	$21.80
2030	$32.35	$24.95	$2.58	$29.77	$22.37
2031	$32.99	$25.60	$2.64	$30.35	$22.96
2032	$33.68	$26.33	$2.70	$30.98	$23.63
2033	$34.33	$27.03	$2.76	$31.57	$24.27
2034	$35.07	$27.67	$2.82	$32.25	$24.85
2035	$35.98	$28.07	$2.88	$33.10	$25.19
2036	$36.79	$28.66	$2.94	$33.85	$25.72

(1) The avoided cost price is reduced by a wind integration charge of $0.57/MWh ($2016) for wind QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If QF wind resource is not in PacifiCorp's BAA, prices will be increased by the $0.57/MWh ($2016) integration charges.

(2) Wind Integration Cost is $0.57

Columns
- (a) Table 13a Column (d) - OnPeak Renewable Avoided resource cost of 2019 IRP Wind Resource
- (b) Table 13a Column (e) - OffPeak Renewable Avoided resource cost of 2019 IRP Wind Resource
- (c) Unit REC Cost ($/MWH) from "Table 15 RPS"

Exhibit 3
Standard Avoided Cost Prices for Fixed Solar QF
$/MWH

	Standard Avoided Resource			Fixed Solar QF	
Year	On-Peak	Off-Peak	RPS Cost Adjustment	On-Peak	Off-Peak
	($/MWh)	($/MWh)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)
				= (a)- (c)	= (b)- (c)
2019	Market Based Prices			$34.78	$23.62
2020	2019 through 2020 less Solar Integration (2)			$30.80	$21.32
2021	$31.47	$21.77	$2.10	$29.37	$19.67
2022	$31.74	$22.90	$2.15	$29.59	$20.75
2023	$32.10	$24.00	$2.20	$29.90	$21.80
2024	$32.88	$24.51	$2.25	$30.63	$22.26
2025	$33.54	$25.13	$2.30	$31.24	$22.83
2026	$34.14	$25.85	$2.35	$31.79	$23.50
2027	$34.79	$26.55	$2.40	$32.39	$24.15
2028	$35.54	$27.25	$2.46	$33.08	$24.79
2029	$36.33	$27.89	$2.52	$33.81	$25.37
2030	$37.10	$28.62	$2.58	$34.52	$26.04
2031	$37.84	$29.36	$2.64	$35.20	$26.72
2032	$38.62	$30.20	$2.70	$35.92	$27.50
2033	$39.37	$31.00	$2.76	$36.61	$28.24
2034	$40.22	$31.73	$2.82	$37.40	$28.91
2035	$41.26	$32.19	$2.88	$38.38	$29.31
2036	$42.19	$32.86	$2.94	$39.25	$29.92

(1) The avoided cost price is reduced by a solar integration charge of $0.60/MWh ($2016) for solar QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If QF solar resource is not in PacifiCorp's BAA, prices will be increased by the $0.60/MWh ($2016) integration charges.

(2) Solar Integration Cost $0.60

Columns
- (a) Table 13b Column (d) - OnPeak Renewable Avoided resource cost of 2019 IRP Solar Resource
- (b) Table 13b Column (e) - OffPeak Renewable Avoided resource cost of 2019 IRP Solar Resource
- (c) RPS unit Cost ($/MWH) from "Table 15 RPS"

Exhibit 4
Standard Avoided Cost Prices for Tracking Solar QF
$/MWH

Year	Standard Avoided Resource On-Peak	Standard Avoided Resource Off-Peak	RPS Cost Adjustment	Tracking Solar QF On-Peak	Tracking Solar QF Off-Peak
	($/MWh)	($/MWh)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(f)	(g)
				= (a)	= (b)
2019	Market Based Prices			$34.78	$23.62
2020	2019 through 2020 less Solar Integration (2)			$30.80	$21.32
2021	$31.47	$21.77	$2.10	$29.37	$19.67
2022	$31.74	$22.90	$2.15	$29.59	$20.75
2023	$32.10	$24.00	$2.20	$29.90	$21.80
2024	$32.88	$24.51	$2.25	$30.63	$22.26
2025	$33.54	$25.13	$2.30	$31.24	$22.83
2026	$34.14	$25.85	$2.35	$31.79	$23.50
2027	$34.79	$26.55	$2.40	$32.39	$24.15
2028	$35.54	$27.25	$2.46	$33.08	$24.79
2029	$36.33	$27.89	$2.52	$33.81	$25.37
2030	$37.10	$28.62	$2.58	$34.52	$26.04
2031	$37.84	$29.36	$2.64	$35.20	$26.72
2032	$38.62	$30.20	$2.70	$35.92	$27.50
2033	$39.37	$31.00	$2.76	$36.61	$28.24
2034	$40.22	$31.73	$2.82	$37.40	$28.91
2035	$41.26	$32.19	$2.88	$38.38	$29.31
2036	$42.19	$32.86	$2.94	$39.25	$29.92

(1) The avoided cost price is reduced by a solar integration charge of $0.60/MWh ($2016) for solar QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system).
If QF solar resource is not in PacifiCorp's BAA, prices will be increased by the $0.60/MWh ($2016) integration charges.

(2) Solar Integration ($0.60

Columns
- (a) Table 13b Column (d) - OnPeak Renewable Avoided resource cost of 2019 IRP Solar Resource
- (b) Table 13b Column (e) - OffPeak Renewable Avoided resource cost of 2019 IRP Solar Resource
- (f) RPS unit Cost ($/MWH) from "Table 15 RPS"

Exhibit 5

Renewable Standard Avoided Cost Prices for Base Load QF
$/MWH

	Standard Avoided Resource		Renewable Base Load QF Resource					
Year	Avoided Firm Capacity Costs	Energy Only Price	Capacity Contribution	QF Capacity Adder	Capacity Adder Allocated to On-Peak Hours	RPS Cost Adjustment	On-Peak	Off-Peak
	$/kW-yr	$/MWh		($/kW-yr)	($/MWh)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
				= (a) * (c)	(d) *1000 / (100.0%x 8760 x 56%)		(e) + (b) + (f)	= (b) + (f)
2019	Market Based Prices						$35.42	$24.26
2020	2019 through 2020						$31.45	$21.97
2021	Market Based Prices plus RPS Cost					$2.10	$33.88	$26.21
2022	2021 through 2029					$2.15	$36.80	$28.94
2023						$2.20	$39.34	$31.20
2024						$2.25	$43.95	$34.44
2025						$2.30	$47.05	$36.91
2026						$2.35	$49.97	$39.40
2027						$2.40	$49.74	$39.59
2028						$2.46	$49.84	$39.88
2029						$2.52	$53.73	$43.17
2030	$117.65	$47.13	100.0%	117.65	$23.96	$2.58	$73.67	$49.71
2031	$120.35	$49.61	100.0%	120.35	$24.51	$2.64	$76.76	$52.25
2032	$123.11	$52.09	100.0%	123.11	$25.08	$2.70	$79.87	$54.79
2033	$125.81	$54.57	100.0%	125.81	$25.63	$2.76	$82.95	$57.33
2034	$128.57	$56.98	100.0%	128.57	$26.19	$2.82	$85.99	$59.80
2035	$131.40	$55.06	100.0%	131.40	$26.77	$2.88	$84.70	$57.94
2036	$134.29	$55.72	100.0%	134.29	$27.35	$2.94	$86.02	$58.66

Columns

(a) Full fixed cost of a proxy CCCT less capitalized energy
(b) Fuel and Capitalized Energy Cost of the Proxy CCCT
ak Hours 100.0% is the on-peak capacity factor of the Proxy CCCT Resource
56% is the percent of all hours that are on-peak
(e) 100.0% is the on-peak capacity factor of the Proxy CCCT Resource
56% is the percent of all hours that are on-peak

(1) Capacity Contribution of the Avoided Proxy
and Base Load QF resources are assumed to be 100%.

Exhibit 6
Renewable Standard Avoided Cost Prices for Wind QF (1) (2)
$/MWH

Year	Renewable Wind Avoided Resource On-Peak ($/MWh) (a)	Renewable Wind Avoided Resource Off-Peak ($/MWh) (b)	Wind QF Resource On-Peak $/MWh (c) = (a)	Wind QF Resource Off-Peak $/MWh (d) = (b)
2019	Market Based Prices		$34.82	$23.66
2020	2019 through 2020 less Wind Integration (2)		$30.84	$21.36
2021	$27.43	$18.97	$27.43	$18.97
2022	$27.66	$19.96	$27.66	$19.96
2023	$27.97	$20.91	$27.97	$20.91
2024	$28.66	$21.36	$28.66	$21.36
2025	$29.24	$21.91	$29.24	$21.91
2026	$29.76	$22.54	$29.76	$22.54
2027	$30.34	$23.15	$30.34	$23.15
2028	$30.99	$23.76	$30.99	$23.76
2029	$31.68	$24.32	$31.68	$24.32
2030	$32.35	$24.95	$32.35	$24.95
2031	$32.99	$25.60	$32.99	$25.60
2032	$33.68	$26.33	$33.68	$26.33
2033	$34.33	$27.03	$34.33	$27.03
2034	$35.07	$27.67	$35.07	$27.67
2035	$35.98	$28.07	$35.98	$28.07
2036	$36.79	$28.66	$36.79	$28.66

(1) During the sufficiency period, avoided cost prices are reduced by an integration charge of $0.57/MWh ($2016) for wind QF resources located in PacifiCorp's BAA (in-system).
If QF wind resource is not in PacifiCorp's BAA, prices will be increased by the $0.57/MWh ($2016) integration charges.

(2) Wind Integration Charge is $0.57

Columns
(a) Table 13a Column (d) - OnPeak Renewable Avoided resource cost of 2019 IRP Wind Resource
(b) Table 13a Column (e) - OffPeak Renewable Avoided resource cost of 2019 IRP Wind Resource

Exhibit 7

Renewable Standard Avoided Cost Prices for Fixed Solar QF (1)
$/MWH

	Renewable Wind Avoided Resource		Fixed Solar QF	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak
	($/MWh)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)
			= (a) +	= (b)
2019	Market Based Prices		$34.78	$23.62
2020	2019 through 2020		$30.80	$21.32
2021	$31.47	$21.77	$31.47	$21.77
2022	$31.74	$22.90	$31.74	$22.90
2023	$32.10	$24.00	$32.10	$24.00
2024	$32.88	$24.51	$32.88	$24.51
2025	$33.54	$25.13	$33.54	$25.13
2026	$34.14	$25.85	$34.14	$25.85
2027	$34.79	$26.55	$34.79	$26.55
2028	$35.54	$27.25	$35.54	$27.25
2029	$36.33	$27.89	$36.33	$27.89
2030	$37.10	$28.62	$37.10	$28.62
2031	$37.84	$29.36	$37.84	$29.36
2032	$38.62	$30.20	$38.62	$30.20
2033	$39.37	$31.00	$39.37	$31.00
2034	$40.22	$31.73	$40.22	$31.73
2035	$41.26	$32.19	$41.26	$32.19
2036	$42.19	$32.86	$42.19	$32.86

Columns
- (a) Table 13b Column (d) - OnPeak Renewable Avoided resource cost of 2019 IRP Solar Resource
- (b) Table 13b Column (e) - OffPeak Renewable Avoided resource cost of 2019 IRP Solar Resource

(1) Adjustment for integration costs:
During Renewable Sufficiency period, the prices are decreased by Solar integration charges

Exhibit 8

Renewable Standard Avoided Cost Prices for Tracking Solar QF (1)
$/MWH

Year	Renewable Solar Avoided Resource		Tracking Solar QF	
	On-Peak	Off-Peak	On-Peak	Off-Peak
	($/MWh)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)
			= (a)	= (b)
2019	Market Based Prices		$34.78	$23.62
2020	2019 through 2020		$30.80	$21.32
2021	$31.47	$21.77	$31.47	$21.77
2022	$31.74	$22.90	$31.74	$22.90
2023	$32.10	$24.00	$32.10	$24.00
2024	$32.88	$24.51	$32.88	$24.51
2025	$33.54	$25.13	$33.54	$25.13
2026	$34.14	$25.85	$34.14	$25.85
2027	$34.79	$26.55	$34.79	$26.55
2028	$35.54	$27.25	$35.54	$27.25
2029	$36.33	$27.89	$36.33	$27.89
2030	$37.10	$28.62	$37.10	$28.62
2031	$37.84	$29.36	$37.84	$29.36
2032	$38.62	$30.20	$38.62	$30.20
2033	$39.37	$31.00	$39.37	$31.00
2034	$40.22	$31.73	$40.22	$31.73
2035	$41.26	$32.19	$41.26	$32.19
2036	$42.19	$32.86	$42.19	$32.86

Columns

(a) Table 13b Column (d) - OnPeak Renewable Avoided resource cost of 2019 IRP Solar Resource

(b) Table 13b Column (e) - OffPeak Renewable Avoided resource cost of 2019 IRP Solar Resource

(1) Adjustment for integration costs:
During Renewable Sufficiency period, the prices are decreased by Solar integration charges

Exhibit 9
Market Price - Blending Matrix (1)

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2019	1.5%	36.7%	61.8%	100.0%	2.2%	20.5%	77.4%	100.0%
2/1/2019	1.8%	27.7%	70.4%	100.0%	2.6%	38.2%	59.2%	100.0%
3/1/2019	0.0%	52.3%	47.7%	100.0%	3.0%	70.6%	26.4%	100.0%
4/1/2019	0.6%	47.7%	51.7%	100.0%	0.5%	42.8%	56.7%	100.0%
5/1/2019	5.0%	65.8%	29.3%	100.0%	10.0%	63.1%	26.9%	100.0%
6/1/2019	2.9%	88.2%	8.9%	100.0%	4.6%	90.4%	5.1%	100.0%
7/1/2019	17.1%	74.0%	9.0%	100.0%	11.3%	88.7%	0.0%	100.0%
8/1/2019	14.1%	71.1%	14.8%	100.0%	6.5%	93.5%	0.0%	100.0%
9/1/2019	5.0%	92.4%	2.6%	100.0%	2.8%	97.2%	0.0%	100.0%
10/1/2019	0.0%	36.7%	63.3%	100.0%	0.0%	17.8%	82.2%	100.0%
11/1/2019	0.0%	14.6%	85.4%	100.0%	0.0%	16.9%	83.1%	100.0%
12/1/2019	0.0%	27.2%	72.8%	100.0%	0.0%	2.3%	97.7%	100.0%
1/1/2020	0.0%	6.8%	93.2%	100.0%	0.0%	30.0%	70.0%	100.0%
2/1/2020	4.5%	34.1%	61.4%	100.0%	13.9%	6.2%	79.9%	100.0%
3/1/2020	0.0%	50.5%	49.5%	100.0%	1.7%	43.4%	54.8%	100.0%
4/1/2020	2.9%	28.3%	68.8%	100.0%	8.4%	66.0%	25.6%	100.0%
5/1/2020	0.8%	34.4%	64.8%	100.0%	16.9%	50.0%	33.1%	100.0%
6/1/2020	3.1%	88.1%	8.8%	100.0%	23.8%	54.2%	22.0%	100.0%
7/1/2020	19.7%	70.9%	9.3%	100.0%	8.6%	91.4%	0.0%	100.0%
8/1/2020	20.1%	74.0%	5.9%	100.0%	6.0%	73.6%	20.4%	100.0%
9/1/2020	9.0%	86.2%	4.8%	100.0%	0.0%	98.6%	1.4%	100.0%
10/1/2020	0.0%	33.4%	66.6%	100.0%	0.0%	15.9%	84.1%	100.0%
11/1/2020	0.0%	6.4%	93.6%	100.0%	0.0%	3.9%	96.1%	100.0%
12/1/2020	2.6%	25.3%	72.0%	100.0%	0.0%	41.4%	58.6%	100.0%
1/1/2021	0.0%	19.5%	80.5%	100.0%	0.0%	0.0%	100.0%	100.0%
2/1/2021	0.9%	12.9%	86.3%	100.0%	15.5%	23.3%	61.2%	100.0%
3/1/2021	0.0%	30.5%	69.5%	100.0%	2.3%	50.5%	47.2%	100.0%
4/1/2021	0.0%	20.3%	79.7%	100.0%	5.5%	44.1%	50.4%	100.0%
5/1/2021	0.5%	29.6%	69.9%	100.0%	3.7%	73.2%	23.1%	100.0%
6/1/2021	8.5%	87.0%	4.6%	100.0%	4.6%	90.0%	5.4%	100.0%
7/1/2021	11.3%	82.6%	6.2%	100.0%	4.3%	93.6%	2.1%	100.0%
8/1/2021	4.2%	93.3%	2.4%	100.0%	4.1%	92.2%	3.7%	100.0%
9/1/2021	3.9%	90.5%	5.6%	100.0%	0.0%	100.0%	0.0%	100.0%
10/1/2021	0.0%	4.3%	95.7%	100.0%	0.0%	15.2%	84.8%	100.0%
11/1/2021	0.0%	0.0%	100.0%	100.0%	0.0%	0.0%	100.0%	100.0%
12/1/2021	0.0%	10.7%	89.3%	100.0%	0.0%	0.0%	100.0%	100.0%

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2022	0.0%	4.8%	95.2%	100.0%	0.0%	0.0%	100.0%	100.0%
2/1/2022	1.6%	39.6%	58.8%	100.0%	4.1%	25.1%	70.8%	100.0%
3/1/2022	9.2%	37.8%	53.0%	100.0%	7.0%	65.5%	27.5%	100.0%
4/1/2022	0.0%	29.3%	70.7%	100.0%	6.5%	71.7%	21.8%	100.0%
5/1/2022	1.5%	34.8%	63.7%	100.0%	17.8%	79.7%	2.4%	100.0%
6/1/2022	14.3%	75.6%	10.2%	100.0%	58.1%	31.6%	10.3%	100.0%
7/1/2022	10.6%	84.9%	4.5%	100.0%	6.5%	76.9%	16.6%	100.0%
8/1/2022	3.7%	93.8%	2.5%	100.0%	2.3%	80.0%	17.7%	100.0%
9/1/2022	2.0%	81.6%	16.4%	100.0%	0.0%	87.5%	12.5%	100.0%
10/1/2022	0.0%	31.5%	68.5%	100.0%	0.0%	26.6%	73.4%	100.0%
11/1/2022	1.0%	20.3%	78.7%	100.0%	0.0%	4.3%	95.7%	100.0%
12/1/2022	0.8%	20.7%	78.5%	100.0%	0.0%	6.5%	93.5%	100.0%
1/1/2023	0.0%	3.2%	96.8%	100.0%	0.0%	0.0%	100.0%	100.0%
2/1/2023	8.9%	14.8%	76.3%	100.0%	12.6%	39.1%	48.3%	100.0%
3/1/2023	22.0%	36.8%	41.2%	100.0%	8.6%	58.5%	32.9%	100.0%
4/1/2023	10.8%	19.9%	69.3%	100.0%	23.8%	51.7%	24.5%	100.0%
5/1/2023	33.2%	51.4%	15.4%	100.0%	28.0%	65.0%	7.0%	100.0%
6/1/2023	26.1%	67.1%	6.7%	100.0%	42.8%	47.0%	10.2%	100.0%
7/1/2023	35.5%	40.7%	23.8%	100.0%	36.1%	63.1%	0.8%	100.0%
8/1/2023	35.2%	51.8%	13.0%	100.0%	19.3%	66.8%	13.8%	100.0%
9/1/2023	1.8%	49.8%	48.4%	100.0%	0.0%	0.0%	100.0%	100.0%
10/1/2023	6.2%	43.8%	50.0%	100.0%	1.6%	24.5%	73.9%	100.0%
11/1/2023	8.9%	0.0%	91.1%	100.0%	25.2%	39.6%	35.2%	100.0%
12/1/2023	23.3%	36.6%	40.1%	100.0%	0.8%	21.6%	77.6%	100.0%
1/1/2024	0.0%	12.6%	87.4%	100.0%	12.3%	2.1%	85.6%	100.0%
2/1/2024	8.9%	9.4%	81.6%	100.0%	10.6%	27.4%	62.0%	100.0%
3/1/2024	14.1%	39.3%	46.6%	100.0%	14.9%	60.7%	24.4%	100.0%
4/1/2024	13.8%	27.8%	58.4%	100.0%	10.6%	64.5%	24.9%	100.0%
5/1/2024	33.6%	46.1%	20.4%	100.0%	14.0%	81.0%	5.0%	100.0%
6/1/2024	25.0%	63.3%	11.7%	100.0%	32.1%	61.6%	6.3%	100.0%
7/1/2024	29.2%	58.0%	12.9%	100.0%	38.6%	56.9%	4.5%	100.0%
8/1/2024	26.4%	55.4%	18.2%	100.0%	56.8%	41.7%	1.4%	100.0%
9/1/2024	9.1%	66.3%	24.6%	100.0%	36.0%	47.4%	16.6%	100.0%
10/1/2024	5.8%	58.2%	36.0%	100.0%	6.2%	26.8%	66.9%	100.0%
11/1/2024	12.3%	42.9%	44.8%	100.0%	0.6%	17.0%	82.4%	100.0%
12/1/2024	29.2%	52.3%	18.6%	100.0%	1.8%	5.9%	92.3%	100.0%
1/1/2025	0.4%	13.5%	86.1%	100.0%	5.7%	3.0%	91.3%	100.0%
2/1/2025	21.7%	17.2%	61.1%	100.0%	7.4%	25.9%	66.7%	100.0%
3/1/2025	30.7%	31.8%	37.5%	100.0%	8.8%	51.4%	39.8%	100.0%
4/1/2025	14.6%	29.6%	55.8%	100.0%	17.4%	63.7%	18.9%	100.0%
5/1/2025	42.1%	50.5%	7.4%	100.0%	12.0%	80.2%	7.9%	100.0%
6/1/2025	28.0%	61.3%	10.6%	100.0%	43.6%	53.7%	2.7%	100.0%
7/1/2025	31.2%	55.4%	13.4%	100.0%	40.1%	55.7%	4.2%	100.0%
8/1/2025	26.7%	73.3%	0.0%	100.0%	39.0%	49.9%	11.1%	100.0%
9/1/2025	24.9%	51.9%	23.2%	100.0%	31.6%	27.8%	40.6%	100.0%
10/1/2025	9.0%	47.8%	43.2%	100.0%	5.3%	22.1%	72.6%	100.0%
11/1/2025	10.6%	54.6%	34.8%	100.0%	14.1%	51.4%	34.5%	100.0%
12/1/2025	23.9%	38.4%	37.7%	100.0%	18.2%	23.4%	58.4%	100.0%
1/1/2026	0.0%	14.8%	85.2%	100.0%	3.1%	1.7%	95.3%	100.0%
2/1/2026	15.1%	10.4%	74.5%	100.0%	12.0%	23.4%	64.6%	100.0%
3/1/2026	21.6%	38.3%	40.0%	100.0%	14.2%	63.8%	22.0%	100.0%
4/1/2026	10.5%	22.1%	67.4%	100.0%	16.2%	67.9%	15.9%	100.0%
5/1/2026	25.9%	62.0%	12.2%	100.0%	32.8%	55.0%	12.2%	100.0%
6/1/2026	19.1%	71.1%	9.8%	100.0%	22.4%	75.0%	2.6%	100.0%
7/1/2026	35.1%	57.6%	7.4%	100.0%	49.4%	48.8%	1.8%	100.0%
8/1/2026	29.7%	55.9%	14.3%	100.0%	41.3%	53.6%	5.1%	100.0%
9/1/2026	4.9%	70.6%	24.5%	100.0%	32.4%	46.9%	20.7%	100.0%
10/1/2026	10.8%	57.7%	31.5%	100.0%	3.6%	23.9%	72.5%	100.0%
11/1/2026	11.3%	73.2%	15.5%	100.0%	28.7%	62.4%	8.9%	100.0%
12/1/2026	26.6%	33.8%	39.6%	100.0%	33.8%	23.8%	42.5%	100.0%

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2027	1.3%	19.5%	79.2%	100.0%	8.3%	0.0%	91.7%	100.0%
2/1/2027	16.7%	21.7%	61.7%	100.0%	22.3%	21.2%	56.6%	100.0%
3/1/2027	7.0%	47.0%	46.0%	100.0%	0.1%	73.1%	26.8%	100.0%
4/1/2027	22.3%	25.0%	52.7%	100.0%	13.4%	73.0%	13.6%	100.0%
5/1/2027	29.5%	62.7%	7.7%	100.0%	16.6%	67.5%	15.9%	100.0%
6/1/2027	22.3%	62.4%	15.3%	100.0%	30.7%	59.8%	9.5%	100.0%
7/1/2027	28.2%	64.4%	7.4%	100.0%	43.8%	54.5%	1.7%	100.0%
8/1/2027	6.2%	79.6%	14.2%	100.0%	38.3%	50.4%	11.2%	100.0%
9/1/2027	5.2%	79.5%	15.3%	100.0%	40.5%	58.4%	1.1%	100.0%
10/1/2027	9.7%	73.4%	16.8%	100.0%	9.9%	24.5%	65.6%	100.0%
11/1/2027	8.5%	75.4%	16.2%	100.0%	17.3%	48.9%	33.8%	100.0%
12/1/2027	28.5%	33.7%	37.8%	100.0%	36.7%	21.8%	41.6%	100.0%
1/1/2028	2.6%	26.7%	70.6%	100.0%	7.6%	1.7%	90.7%	100.0%
2/1/2028	17.7%	4.7%	77.6%	100.0%	29.0%	11.3%	59.7%	100.0%
3/1/2028	15.4%	31.7%	52.8%	100.0%	10.6%	57.7%	31.7%	100.0%
4/1/2028	23.8%	43.2%	33.0%	100.0%	15.5%	70.9%	13.5%	100.0%
5/1/2028	36.2%	56.9%	6.9%	100.0%	25.7%	65.3%	8.9%	100.0%
6/1/2028	25.4%	63.4%	11.1%	100.0%	34.4%	48.0%	17.6%	100.0%
7/1/2028	16.7%	62.9%	20.5%	100.0%	27.8%	67.6%	4.6%	100.0%
8/1/2028	20.1%	48.9%	31.0%	100.0%	13.9%	72.1%	14.0%	100.0%
9/1/2028	9.5%	51.2%	39.3%	100.0%	36.1%	59.3%	4.5%	100.0%
10/1/2028	7.1%	67.8%	25.2%	100.0%	0.0%	15.1%	84.9%	100.0%
11/1/2028	13.2%	60.0%	26.7%	100.0%	21.6%	52.1%	26.3%	100.0%
12/1/2028	20.7%	34.9%	44.5%	100.0%	28.3%	43.7%	28.0%	100.0%
1/1/2029	2.9%	32.2%	64.9%	100.0%	12.0%	16.0%	72.0%	100.0%
2/1/2029	4.4%	16.7%	78.9%	100.0%	20.6%	14.1%	65.2%	100.0%
3/1/2029	7.6%	40.4%	51.9%	100.0%	8.7%	27.5%	63.8%	100.0%
4/1/2029	19.3%	43.8%	36.9%	100.0%	1.8%	74.7%	23.5%	100.0%
5/1/2029	31.1%	51.9%	17.0%	100.0%	20.4%	72.6%	7.0%	100.0%
6/1/2029	30.8%	50.3%	18.9%	100.0%	21.3%	46.7%	32.1%	100.0%
7/1/2029	5.8%	70.2%	24.0%	100.0%	13.9%	72.0%	14.1%	100.0%
8/1/2029	18.8%	42.0%	39.1%	100.0%	5.5%	74.0%	20.5%	100.0%
9/1/2029	11.0%	48.4%	40.7%	100.0%	12.2%	81.6%	6.2%	100.0%
10/1/2029	15.0%	49.5%	35.6%	100.0%	28.3%	53.2%	18.4%	100.0%
11/1/2029	10.7%	57.6%	31.7%	100.0%	17.1%	60.5%	22.3%	100.0%
12/1/2029	27.8%	42.1%	30.1%	100.0%	32.5%	54.8%	12.8%	100.0%

(1) Blending weights are calculated using system balancing purchases and sales from GRID run using December 2018 Official Forward Market Price Curve

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

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

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

Table 2
Avoided Costs ($/MWh)
Energy Prices

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak (HLH Market Purchase)												
2019	37.26	33.78	26.57	23.23	20.91	30.95	57.81	70.09	39.17	27.26	26.83	31.16
2020	28.98	28.71	24.99	21.33	21.79	22.86	50.26	54.02	46.02	24.69	24.41	29.32
2021	29.18	27.60	25.10	21.34	22.02	24.49	49.94	54.32	49.63	25.07	24.66	28.01
2022	28.15	32.54	29.43	27.02	26.52	26.29	47.84	53.14	49.13	30.73	31.15	33.82
2023	33.64	35.31	32.69	32.26	28.69	26.74	47.56	52.28	47.21	35.12	36.15	38.08
2024	39.61	39.30	35.23	34.12	32.03	29.33	51.56	59.46	57.71	42.03	37.50	42.49
2025	43.60	44.00	38.69	37.02	33.69	31.62	54.37	63.83	61.94	42.52	40.20	45.52
2026	47.73	47.38	43.10	41.00	35.79	33.71	57.53	66.23	63.17	45.05	43.02	47.77
2027	49.58	49.34	42.51	38.99	35.10	33.91	55.30	64.72	62.58	46.98	41.78	47.34
2028	50.02	49.05	42.39	38.10	35.60	33.31	58.10	65.76	60.09	45.02	42.27	48.87
2029	52.36	51.09	45.45	42.11	38.09	35.38	61.86	74.56	66.93	49.07	46.03	51.63
2030	57.10	56.15	48.94	44.39	42.28	38.43	70.87	80.00	74.48	56.63	50.62	56.73
2031	61.83	61.01	52.56	46.86	44.23	43.12	74.33	82.65	76.45	56.71	52.73	59.34
2032	63.76	62.97	56.30	52.29	46.12	45.11	78.00	85.14	79.34	59.70	56.21	62.55
2033	67.61	66.68	57.85	51.34	49.13	49.69	83.69	89.84	84.24	65.73	59.12	66.03
2034	71.26	70.14	60.98	54.35	52.39	51.64	87.64	93.27	84.72	65.76	62.35	68.97
2035	74.88	73.84	61.34	55.21	48.85	46.79	85.01	99.82	86.92	64.24	59.28	65.00
2036	72.38	70.76	61.25	53.97	50.08	51.08	90.77	99.29	91.98	69.77	61.38	68.79
Off-Peak (LLH Market Purchase)												
2019	33.08	29.81	22.12	17.94	13.69	15.10	27.16	34.42	24.81	22.66	23.45	26.83
2020	26.62	24.97	22.09	14.89	14.42	13.92	24.70	28.78	24.58	21.90	21.50	25.30
2021	25.41	24.80	21.73	18.70	15.67	13.43	29.19	34.16	32.35	24.22	23.81	25.84
2022	26.82	27.31	24.56	22.83	18.78	17.55	30.60	34.90	33.50	27.04	28.07	29.48
2023	30.15	29.96	27.73	27.53	22.92	18.44	29.62	35.01	35.32	29.82	29.15	32.40
2024	33.20	33.26	29.77	28.85	25.85	19.63	32.94	39.71	40.91	34.50	32.19	35.48
2025	36.47	36.91	32.76	30.90	28.10	19.59	35.09	44.48	44.30	35.86	33.49	37.36
2026	40.19	40.34	35.75	34.45	30.26	20.66	38.31	46.99	46.21	37.76	35.02	38.66
2027	42.16	41.53	35.28	31.81	30.03	22.07	37.72	46.57	45.93	39.28	35.13	38.70
2028	42.34	41.66	35.45	31.42	29.69	24.07	38.80	46.81	45.13	38.86	34.98	39.85
2029	43.23	43.75	40.62	36.22	31.09	27.65	43.06	52.68	50.88	39.78	37.39	41.44
2030	46.48	47.62	42.84	38.58	34.61	29.74	48.73	59.02	56.96	45.70	41.81	46.02
2031	50.71	50.83	46.61	40.12	37.31	31.06	52.56	62.56	58.75	46.05	43.17	47.94
2032	51.69	52.65	48.76	45.42	39.61	31.95	56.99	65.22	61.42	49.06	46.07	51.06
2033	54.37	56.08	51.20	46.74	42.92	36.07	65.83	71.90	67.67	54.48	48.82	54.15
2034	56.85	59.24	53.97	48.89	44.67	35.17	69.64	76.29	69.28	53.62	51.14	57.27
2035	59.42	61.88	54.02	51.01	41.77	41.47	69.74	78.64	70.53	52.15	47.49	53.02
2036	56.32	59.31	54.32	47.08	44.23	39.10	72.98	82.79	74.35	56.25	49.39	54.82
Combined												
2019	35.46	32.07	24.66	20.96	17.80	24.14	44.63	54.75	33.00	25.29	25.37	29.30
2020	27.97	27.10	23.74	18.56	18.62	19.01	39.27	43.17	36.80	23.49	23.16	27.59
2021	27.56	26.40	23.65	20.20	19.29	19.73	41.02	45.65	42.20	24.71	24.30	27.08
2022	27.57	30.29	27.34	25.22	23.19	22.53	40.43	45.30	42.41	29.14	29.82	31.96
2023	32.14	33.01	30.56	30.23	26.21	23.17	39.84	44.86	42.10	32.84	33.14	35.64
2024	36.86	36.70	32.88	31.86	29.37	25.16	43.55	50.97	50.49	38.79	35.22	39.48
2025	40.54	40.95	36.14	34.39	31.29	26.45	46.08	55.51	54.36	39.65	37.32	42.01
2026	44.49	44.35	39.94	38.18	33.41	28.10	49.27	57.96	55.88	41.92	39.58	43.85
2027	46.39	45.98	39.40	35.90	32.92	28.82	47.74	56.91	55.42	43.67	38.92	43.62
2028	46.72	45.87	39.40	35.23	33.06	29.34	49.80	57.61	53.66	42.37	39.14	44.99
2029	48.43	47.93	43.37	39.58	35.08	32.06	53.78	65.15	60.03	45.08	42.32	47.25
2030	52.54	52.48	46.32	41.89	38.98	34.69	61.35	70.98	66.95	51.93	46.83	52.12
2031	57.05	56.63	50.00	43.96	41.25	37.93	64.97	74.01	68.84	52.13	48.62	54.44
2032	58.57	58.53	53.06	49.33	43.32	39.45	68.96	76.58	71.63	55.13	51.85	57.61
2033	61.92	62.12	54.99	49.36	46.46	43.83	76.01	82.13	77.12	60.89	54.69	60.92
2034	65.06	65.46	57.97	52.00	49.07	44.56	79.90	85.97	78.08	60.54	57.53	63.94
2035	68.23	68.70	58.19	53.40	45.81	44.50	78.44	90.71	79.87	59.04	54.21	59.85
2036	65.47	65.84	58.27	51.01	47.57	45.93	83.12	92.20	84.40	63.96	56.22	62.78
2037	-	-	-	-	-	-	-	-	-	-	-	-

Annual Average

	On-Peak	Off-Peak	Combined
2019	$35.42	$24.26	$30.62
2020	$31.45	$21.97	$27.37
2021	$31.78	$24.11	$28.48
2022	$34.65	$26.79	$31.27
2023	$37.14	$29.00	$33.64
2024	$41.70	$32.19	$37.61
2025	$44.75	$34.61	$40.39
2026	$47.62	$37.05	$43.08
2027	$47.34	$37.19	$42.98
2028	$47.38	$37.42	$43.10
2029	$51.21	$40.65	$46.67
2030	$56.38	$44.84	$51.42
2031	$59.32	$47.31	$54.15
2032	$62.29	$49.99	$57.00
2033	$65.91	$54.19	$60.87
2034	$68.62	$56.34	$63.34
2035	$68.43	$56.76	$63.41
2036	$70.13	$57.58	$64.73

Source Offical Market Price Forecast dated December 2018
Blended Market Prices (Blending weights which are used to calculate blended prices are based on system balancing purchases and sales from GRID run using December 2018 Official Forward Market Price Curve

Table 3
Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs ($/kW-yr)	Simple Cycle CT Fixed Costs ($/kW-yr)	Capitalized Energy Costs ($/kW-yr)	Capitalized Energy Costs 70.5% CF ($/MWh)
	(a)	(b)	(c)	(d)
			((a) - (b))	(c)/(8.760 x 70.5%)
2030	$199.04	$117.65	$81.39	$13.18
2031	$203.62	$120.35	$83.27	$13.48
2032	$208.30	$123.11	$85.19	$13.79
2033	$212.88	$125.81	$87.07	$14.10
2034	$217.56	$128.57	$88.99	$14.41
2035	$222.34	$131.40	$90.94	$14.73
2036	$227.23	$134.29	$92.94	$15.05

Columns
- (a) Table 9 Column (f)
- (b) Table 9 Column (f)
- (c) and (d) Capitalized energy costs are zero since fixed cost of CCCT is lower than the fixed cost of SCCT.

Table 4
Total Standard Avoided Energy Cost

Year	Combined Cycle Gas Price ($/MMBtu)	Combined Cycle Energy Cost ($/MWh)	Capitalized Energy Costs 70.5% CF ($/MWh)	Total Standard Avoided Energy Cost ($/MWh)
	(a)	(b)	(c)	(d)
		(a) x 6.790		(b) + (c)
2030	$5.00	$33.95	$13.18	$47.13
2031	$5.32	$36.12	$13.48	$49.61
2032	$5.64	$38.30	$13.79	$52.09
2033	$5.96	$40.47	$14.10	$54.57
2034	$6.27	$42.57	$14.41	$56.98
2035	$5.94	$40.33	$14.73	$55.06
2036	$5.99	$40.67	$15.05	$55.72

Columns
- (a) Table 10
- (b) 6.790 MWh/MMBtu Heat Rate - Table 9
- (c) Table 3 Column (d)

Table 5
Total Standard Avoided Cost

Year	Avoided Firm Capacity Costs	Total Standard Avoided Energy Cost	Total Standard Avoided Costs At Stated Capacity Factor		
			75%	85%	90%
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
			(b)+(a) x1000/(8760 x 0.75)	(b)+(a) x1000/(8760 x 0.85)	(b)+(a) x1000/(8760 x 0.9)
2030	$117.65	$47.13	$65.04	$62.93	$62.05
2031	$120.35	$49.61	$67.92	$65.77	$64.87
2032	$123.11	$52.09	$70.83	$68.62	$67.70
2033	$125.81	$54.57	$73.72	$71.46	$70.52
2034	$128.57	$56.98	$76.55	$74.25	$73.29
2035	$131.40	$55.06	$75.06	$72.70	$71.72
2036	$134.29	$55.72	$76.16	$73.76	$72.75

Columns
- (a) Table 3 Column (a) minus Column (c)
- (b) Table 4 Column (d)

Table 6
On- & Off- Peak Energy Prices

Year	Avoided Firm Capacity Costs	Capacity Cost Allocated to On-Peak Hours	Total Standard Avoided Energy Cost	On-Peak 4,909 Hours	Off-Peak 3,851 Hours
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
		(a) *1000 / (100.0% x 8760 x 56%		(b) + (c)	(c)
2030	$117.65	$23.96	$47.13	$71.09	$47.13
2031	$120.35	$24.51	$49.61	$74.12	$49.61
2032	$123.11	$25.08	$52.09	$77.17	$52.09
2033	$125.81	$25.63	$54.57	$80.19	$54.57
2034	$128.57	$26.19	$56.98	$83.17	$56.98
2035	$131.40	$26.77	$55.06	$81.82	$55.06
2036	$134.29	$27.35	$55.72	$83.08	$55.72

Columns

(a) Table 3 Column (a) minus Column (c)
(b) Table 9 100.0% is the on-peak capacity factor of the Proxy CCCT Resource
(d) 56% is the percent of all hours that are on-peak
(c) Table 4 Column (d)

Table 3 (Renewable)
Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs ($/kW-yr)	Simple Cycle CT Fixed Costs ($/kW-yr)	Capitalized Energy Costs ($/kW-yr)	Capitalized Energy Costs 70.5% CF ($/MWh)
	(a)	(b)	(c) ((a) - (b))	(d) (c)/(8.760 x 70.5%)
2018	$151.52	$89.56	$61.96	$10.03
2019	$154.85	$91.53	$63.32	$10.25
2020	$158.41	$93.64	$64.77	$10.49
2021	$162.21	$95.89	$66.32	$10.74
2022	$166.10	$98.19	$67.91	$11.00
2023	$170.08	$100.54	$69.54	$11.26
2024	$174.16	$102.95	$71.21	$11.53
2025	$177.99	$105.21	$72.78	$11.78
2026	$181.91	$107.53	$74.38	$12.04
2027	$185.91	$109.90	$76.01	$12.31
2028	$190.19	$112.43	$77.76	$12.59
2029	$194.56	$115.01	$79.55	$12.88
2030	$199.04	$117.65	$81.39	$13.18
2031	$203.62	$120.35	$83.27	$13.48
2032	$208.30	$123.11	$85.19	$13.79
2033	$212.88	$125.81	$87.07	$14.10
2034	$217.56	$128.57	$88.99	$14.41
2035	$222.34	$131.40	$90.94	$14.73
2036	$227.23	$134.29	$92.94	$15.05

Columns
- (a) Table 9 Column (f)
- (b) Table 9 Column (f)
- (c) and (d) Capitalized energy costs are zero since fixed cost of CCCT is lower than the fixed cost of SCCT.

Table 4 (Renewable)
Avoided Capacity Costs

Year	Avoided Firm Capacity Costs ($/kW-yr)
	(a)
2018	$89.56
2019	$91.53
2020	$93.64
2021	$95.89
2022	$98.19
2023	$100.54
2024	$102.95
2025	$105.21
2026	$107.53
2027	$109.90
2028	$112.43
2029	$115.01
2030	$117.65
2031	$120.35
2032	$123.11
2033	$125.81
2034	$128.57
2035	$131.40
2036	$134.29

Columns
- (a) Table 3 (Renewable) Column (a) minus Column (c)

Table 7
Proposed and Current Standard Fixed Avoided Costs
$/MWh

Year	PacifiCorp Standard Base Load QF	Current Standard Base Load QF	Difference Standard Base Load QF	PacifiCorp Standard Wind QF (2)	Current Standard Wind QF (2)	Difference Standard Wind QF (2)	PacifiCorp Standard Fixed Solar QF (2)	Current Standard Fixed Solar QF (2)	Difference Standard Fixed Solar QF (2)	PacifiCorp Standard Tracking Solar QF (2)	Current Standard Tracking Solar QF (2)	Difference Standard Tracking Solar QF
2019	$30.51	$21.70	$8.82	$30.13	$21.23	$8.91	$33.00	$22.92	$10.08	$32.93	$22.88	$10.05
2020	$27.28	$24.23	$3.05	$26.86	$23.73	$3.13	$29.29	$25.31	$3.98	$29.23	$25.27	$3.96
2021	$28.41	$27.50	$0.91	$21.78	$26.98	($5.21)	$27.83	$28.63	($0.80)	$27.76	$28.59	($0.82)
2022	$31.19	$29.22	$1.98	$22.28	$28.69	($6.41)	$28.18	$30.38	($2.20)	$28.12	$30.34	($2.22)
2023	$33.56	$30.89	$2.68	$22.80	$30.33	($7.53)	$28.61	$31.96	($3.35)	$28.56	$31.92	($3.37)
2024	$37.52	$33.24	$4.28	$23.34	$32.66	($9.32)	$29.30	$34.29	($5.00)	$29.24	$34.25	($5.01)
2025	$40.29	$36.06	$4.23	$23.86	$35.47	($11.60)	$29.90	$37.10	($7.20)	$29.85	$37.06	($7.22)
2026	$42.97	$37.30	$5.68	$24.38	$36.68	($12.30)	$30.47	$38.30	($7.83)	$30.42	$38.25	($7.84)
2027	$42.88	$38.48	$4.40	$24.92	$37.85	($12.93)	$31.08	$39.48	($8.40)	$31.02	$39.44	($8.42)
2028	$43.00	$40.40	$2.61	$25.49	$39.73	($14.24)	$31.76	$41.28	($9.53)	$31.71	$41.24	($9.54)
2029	$46.57	$44.11	$2.46	$26.07	$43.43	($17.36)	$32.47	$45.06	($12.59)	$32.41	$45.02	($12.61)
2030	$60.56	$60.37	$0.19	$26.66	$48.29	($21.63)	$33.17	$78.51	($45.35)	$33.11	$79.96	($46.85)
2031	$63.34	$60.89	$2.45	$27.25	$48.56	($21.32)	$33.85	$79.43	($45.58)	$33.79	$80.90	($47.11)
2032	$66.14	$63.98	$2.16	$27.89	$51.39	($23.50)	$34.58	$82.90	($48.32)	$34.52	$84.41	($49.89)
2033	$68.93	$66.51	$2.42	$28.50	$53.65	($25.15)	$35.28	$85.82	($50.54)	$35.22	$87.36	($52.13)
2034	$71.66	$66.41	$5.25	$29.14	$53.29	($24.14)	$36.05	$86.12	($50.07)	$35.99	$87.69	($51.70)
2035	$70.06	$67.99	$2.07	$29.78	$54.59	($24.82)	$36.94	$88.10	($51.16)	$36.88	$89.70	($52.83)
2036	$71.05	$68.29	$2.76	$30.44	$54.62	($24.19)	$37.76	$88.80	($51.04)	$37.70	$90.44	($52.74)

15 Year (2019 - 2033) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$40.61	$37.14	$3.46	$25.30	$34.47	($9.17)	$30.79	$41.35	($10.56)	$30.73	$41.58	($10.85)

Notes: (1) Discount Rate - 2019 IRP Discount Rate
(2) Avoided cost prices reflect wind and solar integration charges for QFs located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .
If the QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charges

15 Year (2020 - 2034) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$42.95	$40.00	$2.95	$24.93	$36.67	($11.74)	$30.75	$45.15	($14.40)	$30.70	$45.46	($14.77)

15 Year (2021 - 2035) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$45.75	$42.84	$2.90	$24.91	$38.80	($13.89)	$31.16	$49.04	($17.87)	$31.11	$49.44	($18.34)

Table 8
Proposed and Current Renewable Standard Fixed Avoided Costs
$/MWh

Year	PacifiCorp Renewable Standard Base Load QF	Current Renewable Standard Base Load QF	Difference Renewable Standard Base Load QF	PacifiCorp Renewable Standard Wind QF (2)	Current Renewable Standard Wind QF (2)	Difference Renewable Standard Wind QF (2)	PacifiCorp Renewable Standard Fixed Solar QF (2)	Current Renewable Standard Fixed Solar QF (2)	Difference Renewable Standard Fixed Solar QF (2)	PacifiCorp Renewable Standard Tracking Solar QF (2)	Current Renewable Standard Tracking Solar QF (2)	Difference Renewable Standard Tracking Solar QF
2019	$30.51	$21.70	$8.82	$30.13	$21.23	$8.91	$33.00	$22.92	$10.08	$32.93	$22.88	$10.05
2020	$27.28	$24.23	$3.05	$26.86	$23.73	$3.13	$29.29	$25.31	$3.98	$29.23	$25.27	$3.96
2021	$30.51	$40.24	($9.73)	$23.88	$27.11	($3.24)	$29.93	$50.61	($20.69)	$29.86	$52.89	($23.03)
2022	$33.34	$41.26	($7.91)	$24.43	$27.79	($3.37)	$30.33	$51.81	($21.47)	$30.27	$54.14	($23.87)
2023	$35.76	$42.25	($6.49)	$25.00	$28.46	($3.45)	$30.81	$52.95	($22.14)	$30.76	$55.34	($24.58)
2024	$39.77	$43.22	($3.45)	$25.59	$29.09	($3.49)	$31.55	$53.98	($22.43)	$31.49	$56.43	($24.94)
2025	$42.59	$44.24	($1.65)	$26.16	$29.76	($3.60)	$32.20	$55.09	($22.89)	$32.15	$57.61	($25.46)
2026	$45.32	$45.25	$0.08	$26.73	$30.43	($3.70)	$32.82	$56.28	($23.46)	$32.77	$58.85	($26.08)
2027	$45.28	$46.26	($0.98)	$27.32	$31.11	($3.79)	$33.48	$57.51	($24.03)	$33.42	$60.14	($26.72)
2028	$45.46	$47.28	($1.82)	$27.95	$31.79	($3.84)	$34.22	$58.70	($24.48)	$34.17	$61.39	($27.22)
2029	$49.09	$48.31	$0.78	$28.59	$32.48	($3.89)	$34.99	$59.88	($24.90)	$34.93	$62.63	($27.70)
2030	$63.14	$49.36	$13.78	$29.24	$33.17	($3.93)	$35.75	$61.15	($25.40)	$35.69	$63.96	($28.27)
2031	$65.98	$50.41	$15.57	$29.89	$33.88	($3.99)	$36.49	$62.40	($25.91)	$36.43	$65.27	($28.84)
2032	$68.84	$51.47	$17.38	$30.59	$34.59	($3.99)	$37.28	$63.68	($26.40)	$37.22	$66.61	($29.39)
2033	$71.69	$52.54	$19.15	$31.26	$35.30	($4.04)	$38.04	$64.96	($26.92)	$37.98	$67.95	($29.97)
2034	$74.48	$53.63	$20.85	$31.96	$36.04	($4.08)	$38.87	$66.31	($27.44)	$38.81	$69.36	($30.55)
2035	$72.94	$54.73	$18.21	$32.66	$36.77	($4.11)	$39.82	$67.62	($27.81)	$39.76	$70.74	($30.98)
2036	$73.99	$55.84	$18.15	$33.38	$37.51	($4.13)	$40.70	$68.96	($28.25)	$40.64	$72.14	($31.50)

15 Year (2019 - 2033) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$42.50	$40.93	$1.57	$27.20	$28.92	($1.72)	$32.68	$50.10	($17.42)	$32.63	$52.16	($19.54)

Notes: (1) Discount Rate - 2019 IRP Discount Rate
(2) Avoided cost prices reflect wind and solar integration charges for QFs located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .
If the QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charges

15 Year (2020 - 2034) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$45.09	$43.54	$1.55	$27.07	$30.05	($2.98)	$32.90	$53.72	($20.82)	$32.84	$56.05	($23.21)

15 Year (2021 - 2035) Nominal levelized Price at 6.920% Discount Rate (1)

$/MWh	$48.15	$46.10	$2.05	$27.32	$31.01	($3.69)	$33.57	$57.38	($23.81)	$33.51	$60.00	($26.49)

Table 9
Total Cost of Displaceable Resources

Year	Estimated Capital Cost	Capital Cost at Real Levelized Rate	Fixed O&M	Variable O&M	Total O&M at Expected CF	Total Resource Fixed Costs
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/kW-yr	$/kW-yr
	(a)	(b)	(c)	(d)	(e)	(f)

194 MW - SCCT Frame "F" x1 - East Side Resource (5,050')

2018	$843	$58.66	$30.90	$6.61	$30.90	$89.56
2019		$59.95	$31.58	$6.76	$31.58	$91.53
2020		$61.33	$32.31	$6.92	$32.31	$93.64
2021		$62.80	$33.09	$7.09	$33.09	$95.89
2022		$64.31	$33.88	$7.26	$33.88	$98.19
2023		$65.85	$34.69	$7.43	$34.69	$100.54
2024		$67.43	$35.52	$7.61	$35.52	$102.95
2025		$68.91	$36.30	$7.78	$36.30	$105.21
2026		$70.43	$37.10	$7.95	$37.10	$107.53
2027		$71.98	$37.92	$8.12	$37.92	$109.90
2028		$73.64	$38.79	$8.31	$38.79	$112.43
2029		$75.33	$39.68	$8.50	$39.68	$115.01
2030		$77.06	$40.59	$8.70	$40.59	$117.65
2031		$78.83	$41.52	$8.90	$41.52	$120.35
2032		$80.64	$42.47	$9.10	$42.47	$123.11
2033		$82.41	$43.40	$9.30	$43.40	$125.81
2034		$84.22	$44.35	$9.50	$44.35	$128.57
2035		$86.07	$45.33	$9.71	$45.33	$131.40
2036		$87.96	$46.33	$9.92	$46.33	$134.29
2037		$89.90	$47.35	$10.14	$47.35	$137.25

Source: (a)(c)(d) Plant Costs - 2019 IRP - Table 6.1 & 6.2
(b) = (a) x Payment Factor
(e) = (d) x (8.76 x %) + (c)
(f) = (b) + (e)

	194 MW - SCCT Frame "F" x1 - East Side Resource (5,050')		
	194	MW Plant capacity	MW
2018 $	$843	Plant capacity cost	$/kW
2018 $	$15.97	Fixed O&M & Capitalized O&M	$/kW-yr
2018 $	$14.93	Fixed Pipeline	$/kW-yr
2018 $	$30.90	Fixed O&M Including Fixed Pipeline & Capitalized	$/kW-yr
2018 $	$6.61	Variable O&M and Other Costs	$/MWH
	6.959%	Payment Factor	
	0%	Capacity Factor	

Table 9
Total Cost of Displaceable Resources

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Variable O&M $/MWh	Total O&M at Expected CF $/kW-yr	Total Resource Fixed Costs $/kW-yr	Fuel Cost $/MMBtu	IRP Resource Energy Cost $/MWh	Total Avoided Costs $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)

447 MW - CCCT Dry "G/H", 1x1 - West Side Resource (1,500')

Year	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
2018	$1,429	$97.03	$43.19	$1.83	$54.49	$151.52			
2019		$99.16	$44.14	$1.87	$55.69	$154.85			
2020		$101.44	$45.16	$1.91	$56.97	$158.41			
2021		$103.87	$46.24	$1.96	$58.34	$162.21			
2022		$106.36	$47.35	$2.01	$59.74	$166.10			
2023		$108.91	$48.49	$2.06	$61.17	$170.08			
2024		$111.52	$49.65	$2.11	$62.64	$174.16			
2025		$113.97	$50.74	$2.16	$64.02	$177.99			
2026		$116.48	$51.86	$2.21	$65.43	$181.91			
2027		$119.04	$53.00	$2.26	$66.87	$185.91			
2028		$121.78	$54.22	$2.31	$68.41	$190.19			
2029		$124.58	$55.47	$2.36	$69.98	$194.56			
2030		$127.45	$56.75	$2.41	$71.59	$199.04	$5.00	$33.95	$66.18
2031		$130.38	$58.06	$2.47	$73.24	$203.62	$5.32	$36.12	$69.09
2032		$133.38	$59.40	$2.53	$74.92	$208.30	$5.64	$38.30	$72.03
2033		$136.31	$60.71	$2.59	$76.57	$212.88	$5.96	$40.47	$74.94
2034		$139.31	$62.05	$2.65	$78.25	$217.56	$6.27	$42.57	$77.80
2035		$142.37	$63.42	$2.71	$79.97	$222.34	$5.94	$40.33	$76.33
2036		$145.50	$64.82	$2.77	$81.73	$227.23	$5.99	$40.67	$77.46
2037		$148.70	$66.25	$2.83	$83.53	$232.23	$6.34	$43.05	$80.65

Table 9
Total Cost of Displaceable Resources

Sources, Inputs and Assumptions

Source: (a)(c)(d) Plant Costs - 2019 IRP - Table 6.1 & 6.2
(b) = (a) x 0.0679
(e) = (d) x (8.76 x 70.5%) + (c)
(f) = (b) + (e)
(g) Gas Price Forecast
(h) = 6790 x (g) / 1000
(i) = (f) / (8.76 x 'Capacity Factor') + (h)

447 MW - CCCT Dry "G/H", 1x1 - West Side Resource (1,500')

CCCT Statistics	MW	Percent	Cap Cost	Fixed
CCCT (Dry "G/H" 1x1)	396	88.6%	$1,552	$45.05
CCCT Duct Firing (Dry "G/H" 1x1)	51	11.4%	$478	$28.76
Capacity Weighted	447	100.0%	$1,429	$43.19

CCCT Statistics	MW	CF	aMW	Percent	Variable	Heat Rate
CCCT (Dry "G/H" 1x1)	396	78.0%	309	98.1%	$1.86	6,788
CCCT Duct Firing (Dry "G/H" 1x1)	51	12.0%	6	1.9%	0.15	6,788
Energy Weighted	447	70.5%	315	100.0%	$1.83	6,790
						Rounded

	CCCT	Duct Firing	Plant Costs - 2019 IRP - Table 6.1 & 6.2
	396	51	MW Plant capacity
2018 $	$1,552	$478	Plant capacity cost
2018 $	$21.68	$5.39	Fixed O&M & Capitalized O&M
2018 $	$23.37	$23.37	Fixed Pipeline
	$45.05	$28.76	Fixed O&M Including Fixed Pipeline & Capitalized O&M ($/kW-Yr)
	$1.86	$0.15	Variable O&M and Other Costs
	6,788	6,788	Heat Rate in btu/kWh
	6.790%	6.790%	Payment Factor
	78.0%	12.0%	Capacity Factor
		70.5%	Energy Weighted Capacity Factor
		100.0%	Capacity Factor - On-peak 70.5% / 56.0% (percent of hours on-peak)

Company Official Inflation Forecast Dated December 31, 2018

2017	2.0%	2023	2.4%	2029	2.3%	2035	2.2%
2018	2.3%	2024	2.4%	2030	2.3%	2036	2.2%
2019	2.2%	2025	2.2%	2031	2.3%	2037	2.2%
2020	2.3%	2026	2.2%	2032	2.3%	2038	2.2%
2021	2.4%	2027	2.2%	2033	2.2%	2039	2.2%
2022	2.4%	2028	2.3%	2034	2.2%	2040	2.2%

Table 10
Gas Price Forecast
$/MMBtu

Year	Burner tip West Side Gas Fuel Cost
2030	$5.00
2031	$5.32
2032	$5.64
2033	$5.96
2034	$6.27
2035	$5.94
2036	$5.99

Source
Offical Market Price Forecast dated December 2018

Table 11
Integration Cost

Year	Wind Integration Cost $/MWh	Solar Integration Cost $/MWh
2016	$0.57	$0.60
2017	$0.58	$0.62
2018	$0.59	$0.63
2019	$0.60	$0.64
2020	$0.61	$0.65
2021	$0.62	$0.67
2022	$0.63	$0.69
2023	$0.65	$0.71
2024	$0.67	$0.73
2025	$0.68	$0.75
2026	$0.69	$0.77
2027	$0.71	$0.79
2028	$0.73	$0.81
2029	$0.75	$0.83
2030	$0.77	$0.85
2031	$0.79	$0.87
2032	$0.81	$0.89
2033	$0.83	$0.91
2034	$0.85	$0.93
2035	$0.87	$0.95
2036	$0.89	$0.97
2037	$0.91	$0.99

Note: 2017 IRP Volume II-Appendix F

Company Official Inflation Forecast Dated December 31, 2018

2017	2.0%	2023	2.4%	2029	2.3%	2035	2.2%
2018	2.3%	2024	2.4%	2030	2.3%	2036	2.2%
2019	2.2%	2025	2.2%	2031	2.3%	2037	2.2%
2020	2.3%	2026	2.2%	2032	2.3%	2038	2.2%
2021	2.4%	2027	2.2%	2033	2.2%	2039	2.2%
2022	2.4%	2028	2.3%	2034	2.2%	2040	2.2%

Table 12a
2019 IRP OR Wind Resource-2021
37% Capacity Factor

Year	Estimated Capital Cost	Capital Cost at Real Levelized Rate	Fixed O&M	Fixed Costs	Variable O&M	Tax Credit	Avoided Cost (excluding Integration Cost)	Total Resource Costs	Integration Cost	Capital Cost by Year
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/MWh	$/MWh	$/MWh	$/kW-yr	$/MWh	$/kW
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)	(i)
2019 IRP OR Wind Resource-2021 - 37% Capacity Factor										
2017										
2018	$1,334	$92.03	$28.80	$37.18	$10.00	($15.55)	$31.63	$102.80	$0.93	$1,334
2019			$29.43		$10.22	($15.89)			$0.95	$1,333
2020			$30.11		$10.46	($16.26)			$0.97	$1,333
2021	$1,332	$91.89	$30.83	$37.76	$10.71	($16.65)	$31.82	$103.41	$0.99	$1,332
2022		$94.09	$31.57	$38.67	$10.97	($17.05)	$32.59	$105.90	$1.01	$1,331
2023		$96.35	$32.33	$39.59	$11.23	($17.46)	$33.36	$108.43	$1.03	$1,331
2024		$98.66	$33.11	$40.55	$11.50	($17.88)	$34.17	$111.04	$1.05	$1,330
2025		$100.83	$33.84	$41.44	$11.75	($18.27)	$34.92	$113.48	$1.07	$1,330
2026		$103.05	$34.58	$42.35	$12.01	($18.67)	$35.69	$115.99	$1.09	$1,329
2027		$105.32	$35.34	$43.28	$12.27	($19.08)	$36.47	$118.53	$1.11	$1,329
2028		$107.74	$36.15	$44.27	$12.55	($19.52)	$37.30	$121.24	$1.14	$1,329
2029		$110.22	$36.98	$45.29	$12.84	($19.97)	$38.16	$124.03	$1.17	$1,328
2030		$112.76	$37.83	$46.34	$13.14	($20.43)	$39.05	$126.90	$1.20	$1,328
2031		$115.35	$38.70	$47.40	$13.44	($20.90)	$39.94	$129.81	$1.23	$1,332
2032		$118.00	$39.59	$48.49	$13.75	($21.38)	$40.86	$132.79	$1.26	$1,337
2033		$120.60	$40.46	$49.56	$14.05	($21.85)	$41.76	$135.71	$1.29	$1,342
2034		$123.25	$41.35	$50.65	$14.36	($22.33)	$42.68	$138.70	$1.32	$1,346
2035		$125.96	$42.26	$51.76	$14.68	($22.82)	$43.62	$141.77	$1.35	$1,351
2036		$128.73	$43.19	$52.90	$15.00	($23.32)	$44.58	$144.88	$1.38	$1,355
2037		$131.56	$44.14	$54.06	$15.33	($23.83)	$45.56	$148.08	$1.41	$1,360
2038		$134.45	$45.11	$55.25	$15.67	($24.35)	$46.57	$151.35	$1.44	$1,365
2039		$137.41	$46.10	$56.47	$16.01	($24.89)	$47.59	$154.65	$1.47	$1,395
2040		$140.43	$47.11	$57.71	$16.36	($25.44)	$48.63	$158.03	$1.50	$1,425
2041		$143.52	$48.15	$58.98	$16.72	($26.00)	$49.70	$161.51	$1.53	$1,457
2042		$146.82	$49.26	$60.33	$17.10	($26.60)	$50.83	$165.21	$1.57	$1,490
2043		$150.20	$50.39	$61.72	$17.49	($27.21)	$52.00	$169.00	$1.61	$1,524

Sources, Inputs and Assumptions

Source:	(c)(f)	Supply-side Resource Table
	(a)	Plant capacity cost, with escalation
	(b)	= (a) x 0.06899
	(d)	= ((b) + (c)) / (8.76 x 37.1%)
	(g)	= (d) + (f)
	(h)	Supply-side Resource Table

2019 IRP OR Wind Resource-2021 - 37% Capacity Factor

	Wind	Cost and Input Assumptions		
2018 $	$1,334	Plant capacity cost	$/kW-yr	
2018 $	$28.80	Fixed O&M, plus on-going capital cost	$/kW-yr	
2018 $	$0.93	Integration Cost	$/MWH	
2018 $	$10.00	Variable O&M	$/MWH	
2018 $	($15.55)	Tax Credit $/MWh	$/MWH	(100% PTC)
	6.899%	Payment Factor		
	37.1%	Capacity Factor		

http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Table_6.1-6.3-TRC_for_Supply-Side_Resource_Options_19_IRP_for_PDF.pdf

2019 IRP Wind Capital Cost Escalation

2017		2026	0.0%	2035	0.3%	
2018		2027	0.0%	2036	0.3%	
2019	-0.1%	2028	0.0%	2037	0.3%	
2020	-0.1%	2029	0.0%	2038	0.3%	
2021	0.0%	2030	0.0%	2039	2.2%	Company Official Inflation Forecast Dated December 31, 2018
2022	0.0%	2031	0.3%	2040	2.2%	
2023	0.0%	2032	0.3%	2041	2.2%	
2024	0.0%	2033	0.3%	2042	2.3%	
2025	0.0%	2034	0.3%	2043	2.3%	

Capital Cost Escalation (see slide 7):
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_October_9_2018_Public_Input_Meeting.pdf

Company Official Inflation Forecast Dated December 31, 2018

2017	2.0%	2026	2.2%	2035	2.2%
2018	2.3%	2027	2.2%	2036	2.2%
2019	2.2%	2028	2.3%	2037	2.2%
2020	2.3%	2029	2.3%	2038	2.2%
2021	2.4%	2030	2.3%	2039	2.2%
2022	2.4%	2031	2.3%	2040	2.2%
2023	2.4%	2032	2.3%	2041	2.2%
2024	2.4%	2033	2.2%	2042	2.3%
2025	2.2%	2034	2.2%	2043	2.3%

Table 12b
2019 IRP WY Wind Resource-2021
44% Capacity Factor

Year	Estimated Capital Cost	Capital Cost at Real Levelized Rate	Fixed O&M	Fixed Costs	Variable O&M	Tax Credit	Avoided Cost (excluding Integration Cost)	Total Resource Costs	Integration Cost	Capital Cost by Year
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/MWh	$/MWh	$/MWh	$/kW-yr	$/MWh	$/kW
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)	(i)
2019 IRP WY Wind Resource-2021 - 44% Capacity Factor										
2017										
2018	$1,301	$89.76	$28.80	$31.04	$0.65	($15.55)	$16.14	$61.65	$0.93	$1,301
2019			$29.43		$0.66	($15.89)			$0.95	$1,300
2020			$30.11		$0.68	($16.26)			$0.97	$1,300
2021	$1,299	$89.62	$30.83	$31.54	$0.70	($16.65)	$15.59	$59.53	$0.99	$1,299
2022		$91.77	$31.57	$32.29	$0.72	($17.05)	$15.96	$60.97	$1.01	$1,298
2023		$93.97	$32.33	$33.07	$0.74	($17.46)	$16.35	$62.44	$1.03	$1,298
2024		$96.23	$33.11	$33.86	$0.76	($17.88)	$16.74	$63.95	$1.05	$1,297
2025		$98.35	$33.84	$34.61	$0.78	($18.27)	$17.12	$65.39	$1.07	$1,297
2026		$100.51	$34.58	$35.37	$0.80	($18.67)	$17.50	$66.84	$1.09	$1,296
2027		$102.72	$35.34	$36.15	$0.82	($19.08)	$17.89	$68.32	$1.11	$1,296
2028		$105.08	$36.15	$36.98	$0.84	($19.52)	$18.30	$69.88	$1.14	$1,296
2029		$107.50	$36.98	$37.83	$0.86	($19.97)	$18.72	$71.49	$1.17	$1,295
2030		$109.97	$37.83	$38.70	$0.88	($20.43)	$19.15	$73.13	$1.20	$1,295
2031		$112.50	$38.70	$39.59	$0.90	($20.90)	$19.59	$74.81	$1.23	$1,299
2032		$115.09	$39.59	$40.50	$0.92	($21.38)	$20.04	$76.54	$1.26	$1,304
2033		$117.62	$40.46	$41.39	$0.94	($21.85)	$20.48	$78.22	$1.29	$1,308
2034		$120.21	$41.35	$42.30	$0.96	($22.33)	$20.93	$79.94	$1.32	$1,313
2035		$122.85	$42.26	$43.23	$0.98	($22.82)	$21.39	$81.70	$1.35	$1,317
2036		$125.55	$43.19	$44.18	$1.00	($23.32)	$21.86	$83.49	$1.38	$1,322
2037		$128.31	$44.14	$45.15	$1.02	($23.83)	$22.34	$85.33	$1.41	$1,326
2038		$131.13	$45.11	$46.14	$1.04	($24.35)	$22.83	$87.21	$1.44	$1,331
2039		$134.01	$46.10	$47.16	$1.06	($24.89)	$23.33	$89.09	$1.47	$1,360
2040		$136.96	$47.11	$48.19	$1.08	($25.44)	$23.83	$91.03	$1.50	$1,390
2041		$139.97	$48.15	$49.25	$1.10	($26.00)	$24.35	$93.02	$1.53	$1,421
2042		$143.19	$49.26	$50.39	$1.13	($26.60)	$24.92	$95.17	$1.57	$1,453
2043		$146.48	$50.39	$51.55	$1.16	($27.21)	$25.50	$97.38	$1.61	$1,487

Sources, Inputs and Assumptions

Source:	(c)(f)	Supply-side Resource Table
	(a)	Plant capacity cost, with escalation
	(b)	= (a) x 0.06899
	(d)	= ((b) + (c)) / (8.76 x 43.6%)
	(g)	= (d) + (f)
	(h)	Supply-side Resource Table

2019 IRP WY Wind Resource-2021 - 44% Capacity Factor

	Wind	Cost and Input Assumptions		
2018 $	$1,301	Plant capacity cost	$/kW-yr	
2018 $	$28.80	Fixed O&M, plus on-going capital cost	$/kW-yr	
2018 $	$0.93	Integration Cost	$/MWH	
2018 $	$0.65	Variable O&M	$/MWH	
2018 $	($15.55)	Tax Credit $/MWh	$/MWH	(100% PTC)

6.899%	Payment Factor
43.6%	Capacity Factor

http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Table_6.1-6.3-TRC_for_Supply-Side_Resource_Options_19_IRP_for_PDF.pdf

2019 IRP Wind Capital Cost Escalation

2017		2026	0.0%	2035	0.3%	
2018		2027	0.0%	2036	0.3%	
2019	-0.1%	2028	0.0%	2037	0.3%	
2020	-0.1%	2029	0.0%	2038	0.3%	
2021	0.0%	2030	0.0%	2039	2.2%	Company Official Inflation Forecast Dated December 31, 2018
2022	0.0%	2031	0.3%	2040	2.2%	
2023	0.0%	2032	0.3%	2041	2.2%	
2024	0.0%	2033	0.3%	2042	2.3%	
2025	0.0%	2034	0.3%	2043	2.3%	

Capital Cost Escalation (see slide 7):
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_October_9_2018_Public_Input_Meeting.pdf

Company Official Inflation Forecast Dated December 31, 2018

2017	2.0%	2026	2.2%	2035	2.2%
2018	2.3%	2027	2.2%	2036	2.2%
2019	2.2%	2028	2.3%	2037	2.2%
2020	2.3%	2029	2.3%	2038	2.2%
2021	2.4%	2030	2.3%	2039	2.2%
2022	2.4%	2031	2.3%	2040	2.2%
2023	2.4%	2032	2.3%	2041	2.2%
2024	2.4%	2033	2.2%	2042	2.3%
2025	2.2%	2034	2.2%	2043	2.3%

Table 12c
2019 IRP UT Solar Resource-2021
33% Capacity Factor

Year	Estimated Capital Cost	Capital Cost at Real Levelized Rate	Fixed O&M	Fixed Costs	Variable O&M	Tax Credit	Avoided Cost (excluding Integration Cost)	Total Resource Costs	Integration Cost	Capital Cost by Year
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/MWh	$/MWh	$/MWh	$/kW-yr	$/MWh	$/kW
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)	(i)
2019 IRP UT Solar Resource-2021 - 33% Capacity Factor										
2017										
2018	$1,268	$64.48	$22.32	$30.49	$0.00	$0.00	$30.49	$86.80	$0.70	$1,268
2019			$22.81		$0.00	$0.00			$0.72	$1,131
2020			$23.33		$0.00	$0.00			$0.74	$971
2021	$957	$48.65	$23.89	$25.48	$0.00	$0.00	$25.48	$72.54	$0.76	$957
2022		$49.81	$24.46	$26.09	$0.00	$0.00	$26.09	$74.27	$0.78	$954
2023		$51.01	$25.05	$26.72	$0.00	$0.00	$26.72	$76.06	$0.80	$952
2024		$52.23	$25.65	$27.36	$0.00	$0.00	$27.36	$77.88	$0.82	$949
2025		$53.38	$26.21	$27.96	$0.00	$0.00	$27.96	$79.59	$0.84	$947
2026		$54.55	$26.79	$28.57	$0.00	$0.00	$28.57	$81.34	$0.86	$944
2027		$55.75	$27.38	$29.20	$0.00	$0.00	$29.20	$83.13	$0.88	$941
2028		$57.03	$28.01	$29.87	$0.00	$0.00	$29.87	$85.04	$0.90	$939
2029		$58.34	$28.65	$30.55	$0.00	$0.00	$30.55	$86.99	$0.92	$936
2030		$59.68	$29.31	$31.26	$0.00	$0.00	$31.26	$88.99	$0.94	$934
2031		$61.05	$29.98	$31.97	$0.00	$0.00	$31.97	$91.03	$0.96	$929
2032		$62.45	$30.67	$32.71	$0.00	$0.00	$32.71	$93.12	$0.98	$924
2033		$63.82	$31.34	$33.42	$0.00	$0.00	$33.42	$95.16	$1.00	$918
2034		$65.22	$32.03	$34.16	$0.00	$0.00	$34.16	$97.25	$1.02	$913
2035		$66.65	$32.73	$34.91	$0.00	$0.00	$34.91	$99.38	$1.04	$908
2036		$68.12	$33.45	$35.68	$0.00	$0.00	$35.68	$101.57	$1.06	$903
2037		$69.62	$34.19	$36.46	$0.00	$0.00	$36.46	$103.81	$1.08	$898
2038		$71.15	$34.94	$37.26	$0.00	$0.00	$37.26	$106.09	$1.10	$893
2039		$72.72	$35.71	$38.09	$0.00	$0.00	$38.09	$108.43	$1.12	$913
2040		$74.32	$36.50	$38.93	$0.00	$0.00	$38.93	$110.82	$1.14	$933
2041		$75.96	$37.30	$39.78	$0.00	$0.00	$39.78	$113.26	$1.17	$953
2042		$77.71	$38.16	$40.70	$0.00	$0.00	$40.70	$115.87	$1.20	$975
2043		$79.50	$39.04	$41.64	$0.00	$0.00	$41.64	$118.54	$1.23	$998

Sources, Inputs and Assumptions

Source:	(c)(f)	Supply-side Resource Table
	(a)	Plant capacity cost, with escalation
	(b)	= (a) x 0.05085
	(d)	= ((b) + (c)) / (8.76 x 32.5%)
	(g)	= (d) + (f)
	(h)	Supply-side Resource Table

2019 IRP UT Solar Resource-2021 - 33% Capacity Factor

	Solar	Cost and Input Assumptions	
2018 $	$1,268	Plant capacity cost	$/kW-yr
2018 $	$22.32	Fixed O&M, plus on-going capital cost	$/kW-yr
2018 $	$0.70	Integration Cost	$/MWH
2018 $	$0.00	Variable O&M	$/MWH
2018 $		Tax Credit $/MWh	$/MWH

5.085%	Payment Factor (including 30% ITC and Bonus Depreciation)
32.5%	Capacity Factor

http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Table_6.1-6.3-TRC_for_Supply-Side_Resource_Options_19_IRP_for_PDF.pdf

2019 IRP Solar Capital Cost Escalation

2017		2026	-0.3%	2035	-0.6%	
2018		2027	-0.3%	2036	-0.6%	
2019	-10.8%	2028	-0.3%	2037	-0.6%	
2020	-14.1%	2029	-0.3%	2038	-0.6%	
2021	-1.5%	2030	-0.3%	2039	2.2%	Company Official Inflation Forecast Dated December 31, 2018
2022	-0.3%	2031	-0.6%	2040	2.2%	
2023	-0.3%	2032	-0.6%	2041	2.2%	
2024	-0.3%	2033	-0.6%	2042	2.3%	
2025	-0.3%	2034	-0.6%	2043	2.3%	

Solar Capital Cost Escalation (see slide 7):
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_October_9_2018_Public_Input_Meeting.pdf

Company Official Inflation Forecast Dated December 31, 2018

2017	2.0%	2026	2.2%	2035	2.2%
2018	2.3%	2027	2.2%	2036	2.2%
2019	2.2%	2028	2.3%	2037	2.2%
2020	2.3%	2029	2.3%	2038	2.2%
2021	2.4%	2030	2.3%	2039	2.2%
2022	2.4%	2031	2.3%	2040	2.2%
2023	2.4%	2032	2.3%	2041	2.2%
2024	2.4%	2033	2.2%	2042	2.3%
2025	2.2%	2034	2.2%	2043	2.3%

Table 12d
2019 IRP Lakeview OR Solar Resource-2021
30% Capacity Factor

Year	Estimated Capital Cost	Capital Cost at Real Levelized Rate	Fixed O&M	Fixed Costs	Variable O&M	Tax Credit	Avoided Cost (excluding Integration Cost)	Total Resource Costs	Integration Cost	Capital Cost by Year
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/MWh	$/MWh	$/MWh	$/kW-yr	$/MWh	$/kW
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)	(i)
2019 IRP Lakeview OR Solar Resource-2021 - 30% Capacity Factor										
2017										
2018	$1,329	$67.58	$22.66	$34.68	$0.00	$0.00	$34.68	$90.24	$0.70	$1,329
2019			$23.16		$0.00	$0.00			$0.72	$1,185
2020			$23.69		$0.00	$0.00			$0.74	$1,018
2021	$1,003	$50.99	$24.26	$28.92	$0.00	$0.00	$28.92	$75.25	$0.76	$1,003
2022		$52.21	$24.84	$29.62	$0.00	$0.00	$29.62	$77.05	$0.78	$1,000
2023		$53.46	$25.44	$30.33	$0.00	$0.00	$30.33	$78.90	$0.80	$997
2024		$54.74	$26.05	$31.05	$0.00	$0.00	$31.05	$80.79	$0.82	$995
2025		$55.94	$26.62	$31.73	$0.00	$0.00	$31.73	$82.56	$0.84	$992
2026		$57.17	$27.21	$32.43	$0.00	$0.00	$32.43	$84.38	$0.86	$989
2027		$58.43	$27.81	$33.15	$0.00	$0.00	$33.15	$86.24	$0.88	$987
2028		$59.77	$28.45	$33.91	$0.00	$0.00	$33.91	$88.22	$0.90	$984
2029		$61.14	$29.10	$34.68	$0.00	$0.00	$34.68	$90.24	$0.92	$981
2030		$62.55	$29.77	$35.48	$0.00	$0.00	$35.48	$92.32	$0.94	$979
2031		$63.99	$30.45	$36.30	$0.00	$0.00	$36.30	$94.44	$0.96	$973
2032		$65.46	$31.15	$37.13	$0.00	$0.00	$37.13	$96.61	$0.98	$968
2033		$66.90	$31.84	$37.95	$0.00	$0.00	$37.95	$98.74	$1.00	$963
2034		$68.37	$32.54	$38.79	$0.00	$0.00	$38.79	$100.91	$1.02	$957
2035		$69.87	$33.26	$39.64	$0.00	$0.00	$39.64	$103.13	$1.04	$952
2036		$71.41	$33.99	$40.51	$0.00	$0.00	$40.51	$105.40	$1.06	$947
2037		$72.98	$34.74	$41.40	$0.00	$0.00	$41.40	$107.72	$1.08	$941
2038		$74.59	$35.50	$42.31	$0.00	$0.00	$42.31	$110.09	$1.10	$936
2039		$76.23	$36.28	$43.24	$0.00	$0.00	$43.24	$112.51	$1.12	$957
2040		$77.91	$37.08	$44.20	$0.00	$0.00	$44.20	$114.99	$1.14	$978
2041		$79.62	$37.90	$45.17	$0.00	$0.00	$45.17	$117.52	$1.17	$999
2042		$81.45	$38.77	$46.21	$0.00	$0.00	$46.21	$120.22	$1.20	$1,022
2043		$83.32	$39.66	$47.27	$0.00	$0.00	$47.27	$122.98	$1.23	$1,046

Sources, Inputs and Assumptions

Source:	(c)(f)	Supply-side Resource Table
	(a)	Plant capacity cost, with escalation
	(b)	= (a) x 0.05085
	(d)	= ((b) + (c)) / (8.76 x 29.7%)
	(g)	= (d) + (f)
	(h)	Supply-side Resource Table

	2019 IRP Lakeview OR Solar Resource-2021 - 30% Capacity Factor		
	Solar	**Cost and Input Assumptions**	
2018 $	$1,329	Plant capacity cost	$/kW-yr
2018 $	$22.66	Fixed O&M, plus on-going capital cost	$/kW-yr
2018 $	$0.70	Integration Cost	$/MWH
2018 $	$0.00	Variable O&M	$/MWH
2018 $		Tax Credit $/MWh	$/MWH

5.085%	Payment Factor (including 30% ITC and Bonus Depreciation)
29.7%	Capacity Factor

http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Table_6.1-6.3-TRC_for_Supply-Side_Resource_Options_19_IRP_for_PDF.pdf

2019 IRP Solar Capital Cost Escalation						
2017		2026	-0.3%	2035	-0.6%	
2018		2027	-0.3%	2036	-0.6%	
2019	-10.8%	2028	-0.3%	2037	-0.6%	
2020	-14.1%	2029	-0.3%	2038	-0.6%	
2021	-1.5%	2030	-0.3%	2039	2.2%	Company Official Inflation Forecast Dated December 31, 2018
2022	-0.3%	2031	-0.6%	2040	2.2%	
2023	-0.3%	2032	-0.6%	2041	2.2%	
2024	-0.3%	2033	-0.6%	2042	2.3%	
2025	-0.3%	2034	-0.6%	2043	2.3%	

Solar Capital Cost Escalation (see slide 7):
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_October_9_2018_Public_Input_Meeting.pdf

Company Official Inflation Forecast Dated December 31, 2018					
2017	2.0%	2026	2.2%	2035	2.2%
2018	2.3%	2027	2.2%	2036	2.2%
2019	2.2%	2028	2.3%	2037	2.2%
2020	2.3%	2029	2.3%	2038	2.2%
2021	2.4%	2030	2.3%	2039	2.2%
2022	2.4%	2031	2.3%	2040	2.2%
2023	2.4%	2032	2.3%	2041	2.2%
2024	2.4%	2033	2.2%	2042	2.3%
2025	2.2%	2034	2.2%	2043	2.3%

Table 13a
2019 IRP Wind Resource
Adjusted to On-Peak / Off-Peak Prices

Year	Renewable Avoided Resource Cost $/MWH	On-Peak / Off-Peak Factors On-Peak	Off-Peak	On-Peak Renewable Avoided Resource Cost On-Peak	Off-Peak Renewable Avoided Resource Cost Off-Peak
	(a)	(b)	(c)	(d)	(e)
				(a) x (b)	(a) x (c)
2021	$23.70	1.1571	0.8004	$27.43	$18.97
2022	$24.27	1.1396	0.8223	$27.66	$19.96
2023	$24.86	1.1254	0.8414	$27.97	$20.91
2024	$25.45	1.1260	0.8392	$28.66	$21.36
2025	$26.02	1.1239	0.8421	$29.24	$21.91
2026	$26.59	1.1192	0.8474	$29.76	$22.54
2027	$27.18	1.1161	0.8518	$30.34	$23.15
2028	$27.80	1.1145	0.8547	$30.99	$23.76
2029	$28.44	1.1139	0.8550	$31.68	$24.32
2030	$29.10	1.1117	0.8575	$32.35	$24.95
2031	$29.76	1.1085	0.8600	$32.99	$25.60
2032	$30.45	1.1060	0.8647	$33.68	$26.33
2033	$31.12	1.1031	0.8686	$34.33	$27.03
2034	$31.80	1.1027	0.8700	$35.07	$27.67
2035	$32.51	1.1069	0.8637	$35.98	$28.07
2036	$33.22	1.1076	0.8626	$36.79	$28.66

Columns

(a) Average of Renewable Avoided costs of Oregon and Wyoming Wind Resources from 2019 IRP multiplied by HLH/LLH Spread

(b) Ratio blended market On-Peak to annual prices

(c) Ratio blended market Off-Peak to annual prices

Table 13b
2019 IRP Solar Resource
Adjusted to On-Peak / Off-Peak Prices

	Renewable Avoided Resource Cost	On-Peak / Off-Peak Factors		On-Peak Renewable Avoided Resource Cost	Off-Peak Renewable Avoided Resource Cost
Year	$/MWH	On-Peak	Off-Peak	On-Peak	Off-Peak
	(a)	(b)	(c)	(d)	(e)
				(a) x (b)	(a) x (c)
2021	$27.20	1.1571	0.8004	$31.47	$21.77
2022	$27.85	1.1396	0.8223	$31.74	$22.90
2023	$28.52	1.1254	0.8414	$32.10	$24.00
2024	$29.20	1.1260	0.8392	$32.88	$24.51
2025	$29.84	1.1239	0.8421	$33.54	$25.13
2026	$30.50	1.1192	0.8474	$34.14	$25.85
2027	$31.17	1.1161	0.8518	$34.79	$26.55
2028	$31.89	1.1145	0.8547	$35.54	$27.25
2029	$32.62	1.1139	0.8550	$36.33	$27.89
2030	$33.37	1.1117	0.8575	$37.10	$28.62
2031	$34.14	1.1085	0.8600	$37.84	$29.36
2032	$34.92	1.1060	0.8647	$38.62	$30.20
2033	$35.69	1.1031	0.8686	$39.37	$31.00
2034	$36.47	1.1027	0.8700	$40.22	$31.73
2035	$37.27	1.1069	0.8637	$41.26	$32.19
2036	$38.09	1.1076	0.8626	$42.19	$32.86

Columns

(a) Average of Renewable Avoided costs of OR and Wyoming Solar Resources from 2019 IRP multiplied by HLH/LLH Spread

(b) Ratio blended market On-Peak to annual prices

(c) Ratio blended market Off-Peak to annual prices

Table 14 - PAC RPS Compliance Report

7/12/2018 Corrected

https://edocs.puc.state.or.us/efdocs/HAQ/um1959haq124535.pdf

	13,200,282	Sold to OR Retail customers (OAR 860-083-0350(2)(a), p. 2)
MWH	1,980,042	Used for Compliance (OAR 860-083-0350(2)(m), pg. 11)
	$3,796,066	Cost (OAR 860-083-0350(2)(n), pg. 11)
(2017$)	$1.92	RPS Compliance Value from RVOS Order 19-021
2018	$1.96	
2019	$2.00	
2020	$2.05	
2021	$2.10	
2022	$2.15	
2023	$2.20	
2024	$2.25	
2025	$2.30	
2026	$2.35	
2027	$2.40	
2028	$2.46	
2029	$2.52	
2030	$2.58	
2031	$2.64	
2032	$2.70	
2033	$2.76	
2034	$2.82	
2035	$2.88	
2036	$2.94	
2037	$3.00	
2038	$3.07	
2039	$3.14	
2040	$3.21	
2041	$3.28	
2042	$3.36	
2043	$3.44	

	Company Official Inflation Forecast Dated December 31, 2018				
2017	2.0%	2026	2.2%	2035	2.2%
2018	2.3%	2027	2.2%	2036	2.2%
2019	2.2%	2028	2.3%	2037	2.2%
2020	2.3%	2029	2.3%	2038	2.2%
2021	2.4%	2030	2.3%	2039	2.2%
2022	2.4%	2031	2.3%	2040	2.2%
2023	2.4%	2032	2.3%	2041	2.2%
2024	2.4%	2033	2.2%	2042	2.3%
2025	2.2%	2034	2.2%	2043	2.3%

PACIFIC POWER
AVOIDED COST CALCULATION-STAFF PROPOSAL

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – MARCH 2019

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – MARCH 2019

Standard avoided cost rates are paid to eligible small qualifying facilities (QFs). Oregon avoided cost filing requirements as listed in OAR 860-029-0040 and 860-029-0080 require the Company to file updated avoided costs at least every two years. The Commission Order No. 14-058, requires the Oregon investor owned utilities to update avoided cost prices annually on May 1 of each year and within 30-days of Integrated Resource Plan (IRP) acknowledgment. Annual updates, filed on May 1 of each year, are required to update the following data inputs: (1) natural gas prices; (2) on-peak and off-peak forward looking electricity market prices; (3) production tax credit status; and (4) any other action or change in an acknowledged IRP relevant to the calculation of avoided costs.

The last Oregon avoided costs were approved on July 24, 2018.

Sufficiency and Deficiency Periods

In Docket UM-1396 Order 10-488, the Commission directed that the start date of the first "major resource acquisition" in the action plan of the IRP determines the resource "sufficiency" and "deficiency" periods to be used in calculations of standard avoided cost prices. The sufficiency and deficiency periods used in this filing are based on the 2017 IRP which was acknowledged by the Commission on March 27, 2018.

Table 1 presents 2017 IRP Preferred Portfolio and shows that the earliest acquisition of a Combine Cycle Combustion Turbine (CCCT) is planned to be in 2030. Therefore, the resource sufficiency period for the standard avoided cost rates is from 2018-2029 and the non-renewable resource deficiency period starts in 2030. Table 1 also shows that earliest acquisition of the utility scale renewable resource is in 2021, and therefore the start of the renewable resource deficiency period is 2021.

Avoided Cost Calculation

Based on the 2017 IRP preferred portfolio shown in **Table 1**, the standard avoided cost calculation is separated into two distinct periods: (1) Standard non-renewable resource sufficiency (2019 through 2029) period; and (2) Standard non-renewable resource deficiency (2030 and beyond) period. During the non-renewable resource sufficiency period (2019 through 2029), standard avoided energy costs are based on blended market prices. Market prices from the Company's Official Forward Price Curve are weighted by market transactions required to support the addition of an assumed 50 MW Oregon

Qualified Facility. To calculate the weighting, two production cost studies are prepared. The only difference between the two studies is an assumed 50 aMW, zero running cost resource. System balancing sales and purchase volumes are extracted from both studies and the change between the two studies is calculated for each market hub. This volume impact is used to weight the Company's Official Market Price Forecast on-peak and off-peak market prices for COB, Mid-Columbia, and Palo Verde for each month. **Table 2** shows the result of this calculation.

The sufficiency period for standard renewable rates is 2019 through 2020 and the standard renewable resource deficiency period starts in 2021. During the renewable resource sufficiency period (2019 through 2020), the renewable avoided energy costs are based on blended market prices.

During the non-renewable resource deficiency period, the avoided costs are based on the fixed and variable costs of a CCCT proxy resource that could be avoided or deferred. The capacity and fixed costs of CCCT proxy resource used to set standard avoided cost rates beginning in 2030 is a west side CCCT from the 2019 IRP Supply Side Table.[1]

Since CCCTs are built as base load units that provide both capacity and energy, it is appropriate to split the fixed costs of this unit into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT), which is usually acquired as a capacity resource, defines the portion of the fixed cost of the CCCT that is assigned to capacity.[2] Fixed costs associated with the construction of a CCCT which are in excess of SCCT costs are assigned to energy and are added to the variable production (fuel) cost of the CCCT to determine the total avoided energy costs. **Table 3** shows the capitalized energy costs, which are calculated based on the difference between fixed costs of CCCT and SCCT. The fuel cost of the CCCT defines the avoided variable energy costs. The gas price forecast used as the basis for the CCCT fuel cost is discussed later in this document.

During standard renewable resource deficiency period, the standard renewable avoided cost prices are based on resource costs of renewable proxy wind resource from the 2019 IRP Supply Side Table. The standard renewable on-peak price also includes a capacity adder calculated based on the fixed costs of the SCCT adjusted by the incremental capacity contribution of the QF resource relative to the avoided renewable proxy resource. The capacity adder is allocated to on peak hours by using the on peak capacity factor of the QF resource.

Table 4 shows the CCCT fuel cost, the addition of capitalized energy costs at an assumed 72.1% capacity factor, and the total avoided energy costs.

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[1] 396 MW CCCT (Dry "G/H" 1x1) - West Side Resource (1500') –as listed in Tables 6.1 and 6.2 of the 2019 IRP. Fuel costs are from the Company's December 2018 Official Forward Price Curve (1812 OFPC).
[2] SCCT Frame ("F"x1) – East Side Resource (5,050'), as listed in Tables 6.1 and 6.2 of the 2019 IRP.

Because energy generated by a QF may vary, total standard avoided costs are calculated at 75%, 85% and 90% capacity factor to illustrate the impact of differing generation levels. This calculation is shown in **Table 5**.

Standard avoided costs are differentiated between on-peak and off-peak periods, with capacity costs allocated to on-peak periods. On an annual basis, approximately 56% of all hours are on-peak and 44% are off-peak. **Table 6** shows the calculation of on-peak and off-peak avoided energy prices.

For informational purposes, **Tables 7 and 8** show a comparison between current avoided costs currently in effect in Oregon and the avoided costs proposed by Staff in this filing. An alternate version of Tables 7 and 8 compares Staff's proposal to the Company's proposed avoided costs.

Table 9 shows the calculation of the total fixed costs and fuel costs of the CCCT and SCCT that are used in **Table 3** and **Table 4**. In this filing, the Company's thermal proxy resource is a CCCT located on the west side of the Company's system. Current Commission approved standard non-renewable avoided costs are also based upon a CCCT located on the west side of the Company's system. The costs of SCCT and CCCT resources are updated based on 2019 Supply Side Table. Inflation forecast is not updated and still based on values from March 2018 Official Forward Price Curve.

Gas Price Forecast

Gas prices used in this filing utilize the Company's December 2018 Official Forward Price Curve (1812 OFPC). **Table 10** shows the natural gas price used in this avoided cost calculation.

Table 11 shows wind and solar integration costs used in 2017 IRP.

Table 12 shows the calculation of total resource cost of the renewable proxy wind plant in Wyoming. The capacity costs, fixed O&M plus on-going capital costs, variable O&M, PTC tax credit and capacity factor values of the Wyoming Wind resource are updated based on 2019 IRP Supply Side Table. The total cost of the proxy wind resource is used in the calculation of standard renewable avoided cost rates as shown in "**Exhibits 5 through 8**".

Table 13 shows the calculation of on-peak and off-peak standard renewable avoided cost prices by applying on-peak and off-peak factors. On-peak and off-peak factors are calculated as a ratio of the average annual on-peak Mid-C market price to the flat Mid-C market price.

Exhibit 1- Std Base Load QF tab shows the calculation of proposed standard avoided cost rates for a base load QF. On and off-peak avoided cost rates are based on blended

market rates for 2019-2029. For 2030 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the CCCT proxy. The on-peak price also includes a capacity adder based on the fixed costs of the SCCT proxy (in $/kW-yr). The adjusted capacity adder in $/kW-yr is allocated to on peak hours by using the on peak capacity factor of the base load QF resource, which is assumed to be equal to on peak capacity factor of CCCT proxy resource.

Exhibit 2- Std Wind QF tab shows the calculation of proposed standard avoided cost rates for a wind QF. On and off-peak avoided cost rates are based on blended market rates for 2019-2029. For 2030 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the CCCT proxy. The on-peak price also includes a capacity adder calculated based on fixed costs of SCCT (in $/kW-yr) adjusted by the expected capacity contribution of a wind QF as identified in the 2017 IRP (West side Wind: 11.8%). The fixed costs of SCCT was updated based on 2019 Supply Side Table. The adjusted capacity adder (in $/kW-yr) is allocated to on peak hours by using the on peak capacity factor of a west side wind QF resource. Standard avoided cost rates for a wind QF are reduced by a wind integration charge of $0.57/MWh ($2016).

Exhibits 3 & 4- Std Solar QF tab shows the calculation of proposed standard avoided cost rates for a solar QF. On and off-peak avoided cost rates are based on blended market rates for 2019-2029. For 2030 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the CCCT proxy. The on-peak price also includes a capacity adder calculated based on the fixed costs of SCCT (in $/kW-yr) adjusted by expected capacity contribution of a solar QF as identified in the 2017 IRP (West side fixed solar: 53.9%, tracking solar: 64.8%). The fixed costs of SCCT was updated based on 2019 Supply Side Table. The adjusted capacity adder (in $/kW-yr) is allocated to on peak hours by using the on peak capacity factor of a solar QF resource. Standard avoided cost rates for a solar QF are reduced by a solar integration charge of $0.60/MWh ($2016).

Exhibit 5- Renewable Base Load tab shows the calculation of proposed standard renewable avoided cost rates for renewable base load QF. For 2019-2020, on- and off-peak renewable avoided cost rates are based on blended market rates. For 2021 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the renewable wind proxy resource as calculated in Table 12 and Table 13 with resource costs updated based on 2019 IRP Supply Side Table. Starting in 2021, the standard renewable on-peak price also includes a capacity adder calculated based on the fixed costs of the SCCT (in $/kW-yr), adjusted by the incremental capacity contribution of a renewable Base Load QF relative to the avoided renewable east side wind proxy resource. The fixed costs of SCCT was updated based on 2019 Supply Side Table. The adjusted capacity adder in $/kW-yr is allocated to on peak hours by using the on peak capacity factor of a base load QF resource, which is assumed to be equal to on peak capacity factor of CCCT proxy resource. During resource deficiency period rates are increased by avoided wind integration charge.

Exhibit 6- Renewable Wind tab shows the calculation of proposed standard renewable avoided cost rates for a wind QF. On- and off-peak renewable avoided cost rates are based on blended market rates for 2019-2020. For 2021 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the renewable wind proxy resource as calculated in Table 13 reflecting resource costs from 2019 IRP Supply Side Table. Starting in 2021, the standard renewable on-peak price also includes a capacity adder calculated based on the fixed costs of the SCCT (in $/kW-yr), adjusted by the incremental capacity contribution of a renewable west side Wind QF relative to the capacity contribution of the avoided east side renewable proxy wind resource. The fixed costs of SCCT was updated based on 2019 Supply Side Table. The adjusted capacity adder in $/kW-yr is allocated to on peak hours by using the on peak capacity factor of a west side wind QF resource. During renewable resource sufficiency period of 2018-2020, the standard renewable avoided cost rates for a wind QF are reduced by wind integration charge.

Exhibits 7 & 8- Renewable Solar tab shows the calculation of proposed standard renewable avoided cost rates for a Renewable Solar QF. On- and off-peak renewable avoided cost rates are based on blended market rates for 2019-2020. For 2021 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the renewable wind proxy resource as calculated in Table 12 and Table 13 with resource costs updated based on 2019 IRP Supply Side Table.. Starting in 2021, the standard renewable on-peak price also includes a capacity adder calculated based on the fixed costs of SCCT (in $/kW-yr), adjusted by the incremental capacity contribution of a renewable Fixed and Tracking Solar QF relative to the avoided renewable east side wind proxy resource. The fixed costs of SCCT was updated based on 2019 Supply Side Table. The adjusted capacity adder in $/kW-yr is allocated to on peak hours by using the on peak capacity factors of a solar QF resource. During renewable resource sufficiency period, the standard renewable avoided costs rates for fixed and tracking solar QF resources are reduced by solar integration charge. During renewable resource deficiency period, the rates are adjusted by the difference in avoided wind and solar integration charges.

Exhibit 9– Blending tab shows the market blending used to weight the Company's Official Forward Price Curve on-peak and off-peak market prices at COB, Palo Verde and Mid-Columbia by month, which are used in the calculation of rates shown in **Table 2.**

PACIFIC POWER
AVOIDED COST CALCULATION-<u>PACIFICORP PROPOSAL</u>

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – MARCH 2019

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – MARCH 2019

Standard avoided cost rates are paid to eligible small qualifying facilities (QFs). Oregon avoided cost filing requirements as listed in OAR 860-029-0040 and 860-029-0080 require the Company to file updated avoided costs at least every two years. The Commission Order No. 14-058, requires the Oregon investor owned utilities to update avoided cost prices annually on May 1 of each year and within 30-days of Integrated Resource Plan (IRP) acknowledgment. Annual updates, filed on May 1 of each year, are required to update the following data inputs: (1) natural gas prices; (2) on-peak and off-peak forward looking electricity market prices; (3) production tax credit status; and (4) any other action or change in an acknowledged IRP relevant to the calculation of avoided costs.

The last Oregon avoided costs were approved on July 24, 2018.

Sufficiency and Deficiency Periods

In Docket UM-1396 Order 10-488, the Commission directed that the start date of the first “major resource acquisition” in the action plan of the IRP determines the resource “sufficiency” and “deficiency” periods to be used in calculations of standard avoided cost prices. The sufficiency and deficiency periods used in this filing are based on the 2017 IRP which was acknowledged by the Commission on March 27, 2018.

Table 1 presents 2017 IRP Preferred Portfolio and shows that the earliest acquisition of a Combine Cycle Combustion Turbine (CCCT) is planned to be in 2030. Therefore, the resource sufficiency period for the standard avoided cost rates is from 2018-2029 and the non-renewable resource deficiency period starts in 2030. Table 1 also shows that earliest acquisition ofa utility scale renewable resource is in 2021, and therefore the start of the renewable resource deficiency period is 2021.

Avoided Cost Calculation

Based on the 2017 IRP preferred portfolio shown in **Table 1**, the standard avoided cost calculation is separated into two distinct periods: (1) Standard non-renewable resource sufficiency (2019 through 2029) period; and (2) Standard non-renewable resource deficiency (2030 and beyond) period. During the non-renewable resource sufficiency period (2019 through 2029), standard avoided energy costs are based on blended market prices. Market prices from the Company’s Official Forward Price Curve are weighted by market transactions required to support the addition of an assumed 50 MW Oregon

Qualified Facility. To calculate the weighting, two production cost studies are prepared. The only difference between the two studies is an assumed 50 aMW, zero running cost resource. System balancing sales and purchase volumes are extracted from both studies and the change between the two studies is calculated for each market hub. This volume impact is used to weight the Company's Official Market Price Forecast on-peak and off-peak market prices for COB, Mid-Columbia, and Palo Verde for each month. **Table 2** shows the result of this calculation.

The sufficiency period for standard renewable rates is 2019 through 2020 and the standard renewable resource deficiency period starts in 2021. During the renewable resource sufficiency period (2019 through 2020), the renewable avoided energy costs are based on blended market prices.

During the non-renewable resource deficiency period, the avoided costs are based on the fixed and variable costs of a CCCT proxy resource that could be avoided or deferred. The capacity and fixed costs of CCCT proxy resource used to set standard avoided cost rates beginning in 2030 is a west side CCCT from the 2019 IRP Supply Side Table.[1]

Since CCCTs are built as base load units that provide both capacity and energy, it is appropriate to split the fixed costs of this unit into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT), which is usually acquired as a capacity resource, defines the portion of the fixed cost of the CCCT that is assigned to capacity.[2] Fixed costs associated with the construction of a CCCT which are in excess of SCCT costs are assigned to energy and are added to the variable production (fuel) cost of the CCCT to determine the total avoided energy costs. **Table 3** shows the capitalized energy costs, which are calculated based on the difference between fixed costs of CCCT and SCCT. The fuel cost of the CCCT defines the avoided variable energy costs. The gas price forecast used as the basis for the CCCT fuel cost is discussed later in this document. Under the Company's proposal, the aforementioned non-renewable resource methodology is only applicable to baseload QFs.

During the standard renewable resource deficiency period, the standard renewable avoided cost prices for wind and solar resources QFs are based on resource costs of renewable proxy resources of the same type as the QF from the 2019 IRP Supply Side Table.
Table 4 shows the CCCT fuel cost, the addition of capitalized energy costs at an assumed 72.1% capacity factor, and the total avoided energy costs.

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[1] 396 MW CCCT (Dry "G/H" 1x1) - West Side Resource (1500') –as listed in Tables 6.1 and 6.2 of the 2019 IRP. Fuel costs are from the Company's December 2018 Official Forward Price Curve (1812 OFPC).
[2] SCCT Frame ("F"x1) – East Side Resource (5,050'), as listed in Tables 6.1 and 6.2 of the 2019 IRP.

Because energy generated by a QF may vary, total standard avoided costs are calculated at 75%, 85% and 90% capacity factor to illustrate the impact of differing generation levels. This calculation is shown in **Table 5**.

Standard avoided costs are differentiated between on-peak and off-peak periods, with capacity costs allocated to on-peak periods. On an annual basis, approximately 56% of all hours are on-peak and 44% are off-peak. **Table 6** shows the calculation of on-peak and off-peak avoided energy prices.

For informational purposes, **Tables 7 and 8** show a comparison of the avoided costs currently in effect in Oregon and PacifiCorp's proposed avoided costs in this filing.

Table 9 shows the calculation of the total fixed costs and fuel costs of the CCCT and SCCT that are used in **Table 3** and **Table 4**. In this filing, the Company's thermal proxy resource is a CCCT located on the west side of the Company's system. Current Commission approved standard non-renewable avoided costs are also based upon a CCCT located on the west side of the Company's system. The costs of SCCT and CCCT resources are updated based on 2019 Supply Side Table. Inflation forecast is updated and based on values from December2018 Official Forward Price Curve.

Gas Price Forecast

Gas prices used in this filing utilize the Company's December 2018 Official Forward Price Curve (1812 OFPC). **Table 10** shows the natural gas price used in this avoided cost calculation.

Table 11 shows wind and solar integration costs used in 2017 IRP.

Table 12a, Table 12b, Table 12c and Table 12d show the calculation of total resource cost of the renewable solar and wind proxy plants from 2019 IRP Supply Side Table. The costsand capacity factor values of IRP wind resources in Oregon and Wyoming, and IRP solar resources in Oregon and Utah .

The total cost of the proxy wind resources is used in the calculation of standard wind avoided cost rates as shown in "**Exhibit 6"**. The total cost of the proxy solar resources is used in the calculation of standard solar avoided cost rates as shown in "**Exhibits 7 and 8".**

Table 13a and Table 13b show the calculation of on-peak and off-peak standard avoided cost prices for the wind and solar proxy resources by applying on-peak and off-peak factors. On-peak and off-peak factors are calculated as a ratio of the average annual on-peak Mid-C market price to the flat Mid-C market price.

Table 14 shows REC prices (in $/MWh) based on the RPS Compliance filing value, as specified in Order 19-021 in the Company's resource value of solar proceeding (UM-1910).

Exhibit 1- Std Base Load QF tab shows the calculation of proposed standard avoided cost rates for a base load QF. On and off-peak avoided cost rates are based on blended market rates for 2019-2029. For 2030 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the CCCT proxy. The on-peak price also includes a capacity adder based on the fixed costs of the SCCT (in $/kW-yr). The fixed costs of SCCT was updated based on 2019 Supply Side Table. The adjusted capacity adder in $/kW-yr is allocated to on peak hours by using the on peak capacity factor of the base load QF resource, which is assumed to be equal to on peak capacity factor of CCCT proxy resource.

Exhibit 2- Std Wind QF tab shows the calculation of proposed standard avoided cost rates for a wind QF. The calculation of prices for non-renewable wind QF is the same as the calculation of prices for non-renewable in Exhibit 6 except in starting in 2021, the standard non-renewable prices for wind QF are reduced by the REC price.

On- and off-peak renewable avoided cost rates are based on blended market rates for 2019-2020. For 2021 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the wind proxy resource as calculated in Table 13a, reflecting resource costs from 2019 IRP Supply Side Table. During renewable resource sufficiency period of 2019-2020, the standard renewable avoided cost rates for a wind QF are reduced by wind integration charge.

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Exhibits 3 & 4- Std Solar QF tab shows the calculation of proposed standard avoided cost rates for a solar QF. The calculation of prices for non-renewable solar QF is the same as the calculation of prices for non-renewable in Exhibit 7&8 except in starting in 2021, the standard non-renewable prices for solar QF are reduced by the REC price.

On- and off-peak renewable avoided cost rates are based on blended market rates for 2019-2020. For 2021 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the solar proxy resource as calculated in Table 13b, reflecting resource costs from 2019 IRP Supply Side Table. During renewable resource sufficiency period, the standard renewable avoided costs rates for fixed and tracking solar QF resources are reduced by solar integration charge.

Exhibit 5- Renewable Base Load tab shows the calculation of proposed standard renewable avoided cost rates for renewable base load QF. The calculation of prices for renewable base load QF is the same as the calculation of prices for non-renewable in Exhibit 1 except in starting in 2021, the standard renewable prices for baseload QF are increased by the REC price.

Exhibit 6- Renewable Wind tab shows the calculation of proposed standard renewable avoided cost rates for a wind QF. On- and off-peak renewable avoided cost rates are based on blended market rates for 2019-2020. For 2021 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the renewable wind proxy resource as calculated in Table 13a, reflecting resource costs from 2019 IRP Supply Side Table. During renewable resource sufficiency period of 2019-2020, the standard renewable avoided cost rates for a wind QF are reduced by wind integration charge.

Exhibits 7 & 8- Renewable Solar tab shows the calculation of proposed standard renewable avoided cost rates for a Renewable Solar QF. On- and off-peak renewable avoided cost rates are based on blended market rates for 2019-2020. For 2021 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the renewable solar proxy resource as calculated in Table 13b, reflecting resource costs from 2019 IRP Supply Side Table. During renewable resource sufficiency period, the standard renewable avoided costs rates for fixed and tracking solar QF resources are reduced by solar integration charge.

Exhibit 9– Blending tab shows the market blending used to weight the Company's Official Forward Price Curve on-peak and off-peak market prices at COB, Palo Verde and Mid-Columbia by month, which are used in the calculation of rates shown in **Table 2.**

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

I. Resource Sufficiency / Deficiency Demarcation

		Explanation	IRP Reference
1.	Non-renewable: Identify the demarcation year for the end of sufficiency period / start of deficiency period.	Deficiency starting in 2030.	Table 8.17 – 2017 IRP Preferred Portfolio, page 244
2.	Non-renewable: Identify the major resource to be acquired (>100 megawatts (MW) and longer than five years) at end of sufficiency period.	West Side Combined-Cycle Combustion Turbine (CCCT) (Dry "G/H" 1x1) with Duct Firing - West Side Resource (1500').	2019 IRP Supply Side Table 6.1 and 6.2 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Table_6.1-6.3-TRC_for_Supply-Side_Resource_Options_19_IRP_for_PDF.pdf
3.	Renewable: Identify the demarcation year for the end of sufficiency period / start of deficiency period.	Deficiency starting in 2021	Table 8.17 – 2017 IRP Preferred Portfolio, page 244
4.	Renewable: Identify the major resource to be acquired (>100 MW and longer than five years) at end of sufficiency period.	Wyoming wind resource starting in 2021	2019 IRP Supply Side Table 6.1 and 6.2

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

II. Gas Price Forecast

		Explanation	IRP Reference
1.	Identify the source of the gas price forecast.	Official forward price curve (OFPC) December 2018	-
2.	If the forecast source differs from that used in the most recent approved avoided cost filing / explain the reason(s) for the change.	The Company updates its OFPC every quarter. The December 2018 OFPC was the most recent curve available at the time of this filing. Currently effective rates were based on the March 2018 OFPC.	-
3.	Provide the yearly forecast price by year / and identify any rounding that has been applied.	Refer to the tabs entitled "Table 10" and "OFPC Source" of the "7_OR Sch 37 AC Study (Staff)_2019 03 05.xlsx"	-
4.	Quantify and describe the extent to which the gas price forecast differs from the most recent approved avoided cost filing, include a description of carbon cost / tax assumption(s).	The Company updates its OFPC every quarter. The December 2018 OFPC was the most recent curve available that would have been used in the Company's March 2019 update. Currently approved rates were based on March 2018 OFPC. Refer to the spreadsheet entitled "16_MFR - II.Gas Price Forecast_20190307" for the comparison of the gas price forecast. Refer to the files entitled "201803 OFPC - Environmental" and "201812 OFPC - Environmental" for the March 2018 OFPC and December 2018 OFPC carbon tax assumptions.	-

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

III. Sufficiency Period Prices

		Explanation	IRP Reference
1.	List the market hub(s) used for market price projections, the source for the forward price curves, and any adjustments or blending used in deriving the sufficiency period prices.	Market prices for California-Oregon Border (COB), Mid-Columbia (Mid-C) and Palo Verde (PV) from the March 2016 OFPC are blended based on change in system balancing purchases and sales using two the Generation and Regulation Initiative Decision Tool (GRID) runs - with and without a 50 MW qualifying facility (QF) resource.	-
2.	Provide the transmission costs assumed used in sufficiency period prices.	No transmission costs are incorporated in standard sufficiency period avoided cost pricing.	-
3.	Provide all other component(s) used to calculate sufficiency period prices.	Prices for wind resources are adjusted to account for wind and solar integration costs. Wind integration cost: \$0.57/MWh (2016\$), Solar integration cost:\$0.60/MWh (2016\$) For the complete calculation of sufficiency period prices, refer to “7_OR Sch 37 AC Study (Staff)_2019 03 05.xlsx”.	Flexible Reserve Study from 2017 IRP, 2017 IRP Volume II-Appendix F, Table F.2 on Page 75

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

IV. Standard Rates Deficiency Period Resource

		Explanation	IRP Reference
1.	Provide the resource type, geographic location, nameplate capacity, and annual capacity factor.	CCCT (Dry "G/H" 1X1) West Side Resource (1,500') with Duct Firing available in 2030, Annual Energy weighted CF is 70.5 percent. Refer to Table 9 of "7_OR Sch 37 AC Study (Staff)_2019 03 05.xlsx"	2019 IRP Supply Side Table 6.1 and 6.2
2.	Provide the source of natural gas supply / and the costs assumed for interconnection / infrastructure upgrades, transmission, storage, and any other costs necessary to deliver gas.	Burner Tip West Side Gas, refer to Table 10 of "7_OR Sch 37 AC Study (Staff)_2019 03 05.xlsx"	-
3.	Provide the assumed heat rate. Include assumptions to account for elevation / temperature, and cooling method.	Refer to Table 9 of "7_OR Sch 37 AC Study (Staff)_2019 03 05.xlsx"	2019 IRP Supply Side Table 6.1 and 6.2
4.	List the costs assumed for interconnection facilities.	-	2019 IRP Supply Side Table 6.1 and 6.2
5.	List the components of transmission costs used and their respective values.	-	2019 IRP Supply Side Table 6.1 and 6.2
6.	List the tax assumptions used.	-	2019 IRP Supply Side Table 6.1 and 6.2

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

V. Renewable Rates Deficiency Period Resource

		Explanation	IRP Reference
1.	Provide the resource type, geographic location / nameplate capacity, and annual capacity factor.	Wyoming wind resource with 43.6% CF from the 2019 IRP Supply Side Table. Refer to Table 12 of "7_OR Sch 37 AC Study (Staff)_2019 03 05.xlsx"	2019 IRP Supply Side Table 6.1 and 6.2
2.	Provide assumptions used for mechanical availability, annual hours of curtailment / and annual megawatt-hours (MWh) of energy curtailed.	None.	
3.	List the costs assumed for interconnection facilities.	-	2019 IRP Supply Side Table 6.1 and 6.2
4.	List the components of transmission costs used and their respective values.	-	2019 IRP Supply Side Table 6.1 and 6.2
5.	List the tax assumptions used. This includes assumed taxes paid (federal, state / local), and assumed tax benefits (e.g. PTC / investment tax credits (ITC) / grants in lieu of credits).	PTC (First Year levelized value of $15.55/MWh (in 2018$) escalated by inflation rate from Marrh 2018 OFPC). Refer to Table 12 of "7_OR Sch 37 AC Study (Staff)_2019 03 05.xlsx"	2019 IRP Supply Side Table 6.1 and 6.2
6.	Provide the capacity contribution value, and the method used to derive the capacity contribution value / for solar and wind resource types.	Capacity Contribution values - Wind: 11.8 percent, Fixed Solar: 53.9 percent, and Tracking Solar: 64.8 percent.	2017 IRP Wind and Solar Capacity Contribution Study, 2017 IRP Volume II-Appendix N, Table N.1, page 316.
7.	Provide the wind integration cost used / and the method used to derive the wind integration cost.	Wind integration cost: $0.57/MWh (2016$), Solar integration cost:$0.60/MWh (2016$)	Flexible Reserve Study from 2017 IRP, 2017 IRP Volume II-Appendix F, Table F.2 on Page 75

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

I. Resource Sufficiency / Deficiency Demarcation

		Explanation	IRP Reference
1.	Non-renewable: Identify the demarcation year for the end of sufficiency period / start of deficiency period.	Deficiency starting in 2030.	Table 8.17 – 2017 IRP Preferred Portfolio, page 244
2.	Non-renewable: Identify the major resource to be acquired (>100 megawatts (MW) and longer than five years) at end of sufficiency period.	West Side Combined-Cycle Combustion Turbine (CCCT) (Dry "G/H" 1x1) with Duct Firing - West Side Resource (1500').	2019 IRP Supply Side Table 6.1 and 6.2 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Table_6.1-6.3-TRC_for_Supply-Side_Resource_Options_19_IRP_for_PDF.pdf
3.	Renewable: Identify the demarcation year for the end of sufficiency period / start of deficiency period.	Deficiency starting in 2021	Table 8.17 – 2017 IRP Preferred Portfolio, page 244
4.	Renewable: Identify the major resource to be acquired (>100 MW and longer than five years) at end of sufficiency period.	Proxy wind resource costs are Average cost of Oregon and Wyoming wind resources starting in 2021 Proxy solar resource costs are Average cost of Utah and Oregon solar resources starting in 2021	2019 IRP Supply Side Table 6.1 and 6.2

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

II. Gas Price Forecast

		Explanation	IRP Reference
1.	Identify the source of the gas price forecast.	Official forward price curve (OFPC) December 2018	-
2.	If the forecast source differs from that used in the most recent approved avoided cost filing / explain the reason(s) for the change.	The Company updates its OFPC every quarter. The December 2018 OFPC was the most recent curve available at the time of this filing. Currently effective rates were based on the March 2018 OFPC.	-
3.	Provide the yearly forecast price by year / and identify any rounding that has been applied.	Refer to the tabs entitled "Table 10" and "OFPC Source" of the 9_OR Sch 37 AC Study (PacifiCorp)_2019 03 05	-
4.	Quantify and describe the extent to which the gas price forecast differs from the most recent approved avoided cost filing, include a description of carbon cost / tax assumption(s).	The Company updates its OFPC every quarter. The December 2018 OFPC was the most recent curve available that would have been used in the Company's March 2019 update. Currently approved rates were based on March 2018 OFPC. Refer to the spreadsheet entitled "16_MFR - II.Gas Price Forecast_20190307" for the comparison of the gas price forecast. Refer to the files entitled "201803 OFPC - Environmental" and "201812 OFPC - Environmental" for the March 2018 OFPC and December 2018 OFPC carbon tax assumptions.	-

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

III. Sufficiency Period Prices

		Explanation	IRP Reference
1.	List the market hub(s) used for market price projections, the source for the forward price curves, and any adjustments or blending used in deriving the sufficiency period prices.	Market prices for California-Oregon Border (COB), Mid-Columbia (Mid-C) and Palo Verde (PV) from the March 2016 OFPC are blended based on change in system balancing purchases and sales using two the Generation and Regulation Initiative Decision Tool (GRID) runs - with and without a 50 MW qualifying facility (QF) resource.	-
2.	Provide the transmission costs assumed used in sufficiency period prices.	No transmission costs are incorporated in standard sufficiency period avoided cost pricing.	-
3.	Provide all other component(s) used to calculate sufficiency period prices.	Prices for wind resources are adjusted to account for wind and solar integration costs. Wind integration cost: $0.57/MWh (2016$), Solar integration cost:$0.60/MWh (2016$) For the complete calculation of sufficiency period prices, refer to “9_OR Sch 37 AC Study (PacifiCorp)_2019 03 05.xlsx” 5.	Flexible Reserve Study from 2017 IRP, 2017 IRP Volume II-Appendix F, Table F.2 on Page 75

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

IV. Standard Rates Deficiency Period Resource

		Explanation	IRP Reference
1.	Provide the resource type, geographic location, nameplate capacity, and annual capacity factor.	CCCT (Dry "G/H" 1X1) West Side Resource (1,500') with Duct Firing available in 2030, Annual Energy weighted CF is 70.5 percent. Refer to Table 9 "9_OR Sch 37 AC Study (PacifiCorp)_2019 03 05.xlsx"	2019 IRP Supply Side Table 6.1 and 6.2
2.	Provide the source of natural gas supply / and the costs assumed for interconnection / infrastructure upgrades, transmission, storage, and any other costs necessary to deliver gas.	Burner Tip West Side Gas, refer to Table 10 of "9_OR Sch 37 AC Study (PacifiCorp)_2019 03 05.xlsx "	-
3.	Provide the assumed heat rate. Include assumptions to account for elevation / temperature, and cooling method.	Refer to Table 9 of "9_OR Sch 37 AC Study (PacifiCorp)_2019 03 05.xlsx	2019 IRP Supply Side Table 6.1 and 6.2
4.	List the costs assumed for interconnection facilities.	-	2019 IRP Supply Side Table 6.1 and 6.2
5.	List the components of transmission costs used and their respective values.	-	2019 IRP Supply Side Table 6.1 and 6.2
6.	List the tax assumptions used.	-	2019 IRP Supply Side Table 6.1 and 6.2

Docket UM 2001 / Compliance Filing
Minimum Filing Requirements
Public Utility Commission of Oregon (OPUC) Order No. 16-174 dated May 13, 2016

V. Renewable Rates Deficiency Period Resource

		Explanation	IRP Reference
1.	Provide the resource type, geographic location / nameplate capacity, and annual capacity factor.	Oregon (37.1 CF) and Wyoming (43.6%) wind resources from the 2019 IRP Supply Side Table. Refer to Table 12a and Table 12b of "9_OR Sch 37 AC Study (PacifiCorp)_2019 03 05.xlsx" ,	2019 IRP Supply Side Table 6.1 and 6.2
2.	Provide assumptions used for mechanical availability, annual hours of curtailment / and annual megawatt-hours (MWh) of energy curtailed.	None.	
3.	List the costs assumed for interconnection facilities.	-	2019 IRP Supply Side Table 6.1 and 6.2
4.	List the components of transmission costs used and their respective values.	-	2019 IRP Supply Side Table 6.1 and 6.2
5.	List the tax assumptions used. This includes assumed taxes paid (federal, state / local), and assumed tax benefits (e.g. PTC / investment tax credits (ITC) / grants in lieu of credits).	PTC (First Year levelized value of $15.55/MWh (in 2018$) escalated by inflation rate from December 2018 OFPC). Refer to Table 12a and Table 12b of "9_OR Sch 37 AC Study (PacifiCorp)_2019 03 05.xlsx"	2019 IRP Supply Side Table 6.1 and 6.2
6.	Provide the capacity contribution value, and the method used to derive the capacity contribution value / for solar and wind resource types.	Capacity Contribution values - Wind: 11.8 percent, Fixed Solar: 53.9 percent, and Tracking Solar: 64.8 percent.	2017 IRP Wind and Solar Capacity Contribution Study, 2017 IRP Volume II-Appendix N, Table N.1, page 316.
7.	Provide the wind integration cost used / and the method used to derive the wind integration cost.	Wind integration cost: $0.57/MWh (2016$), Solar integration cost:$0.60/MWh (2016$)	Flexible Reserve Study from 2017 IRP, 2017 IRP Volume II-Appendix F, Table F.2 on Page 75

State & Federal CO_2: No Update

California cap-and-trade policy assumptions in Aurora

- In the absence of a Federal CO_2 tax, California CO_2 is assumed to continue post 2030. July 25, 2017 Governor Jerry Brown signed into law the extension of California's existing cap-and-trade program to 2030, per Assembly Bill 398.
- Aurora's cap-and-trade prices come from an third-party expert's forecast of California Carbon Allowance (CCA) prices.
- All fossil-fired generating units operating within California generate emissions consistent with the CO_2 content of the fuel and the unit's heat rate
- For instance, a combined cycle plant with a 7,500 Btu/kWh heat rate burning natural gas, with a CO_2 content of 118 lb/MMBtu, would produce 0.44 tons of CO_2 emissions for each MWh generated
- The assumed California CO_2 allowance price is modeled as a dispatch cost adder and applied to plant CO_2 emissions.

October 10, 2017 EPA Chief Scott Pruitt signed a proposal for EPA to withdraw its Clean Power Plan, without an immediate replacement.

- The CPP is no longer assumed and no Federal CO2 program is currently modeled in Aurora.

Official Market Price Projection
Final Documentation

Dec 31, 2018

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Introduction

– The Dec 31, 2018 official forward price curve (OFPC) reflects assumption updates in the following areas:
  - New entrants (retirements) were modeled reflecting resources currently under construction (with verified retirement dates).
  - Renewable forecast was updated to reflect the increased requirement in California to 60% of retail sales by 2030 under SB 100.
  - Natural gas price forecasts were updated through 2040
  - Aurora model output was calibrated using calibration factors from the September 2018 OFPC. The September OFPC was calibrated to 36 months (Sept 2019 – Sept 2022) of forwards, per Sep 5, 2018 as determined by Risk. The decision to not update calibration using fourth quarter forwards stems from inordinately high 2019-2020 forwards brought about by force majeure events affecting natural gas deliverability to the Northwest and Southern California. As such, the Company thought it more prudent to use calibration factors previously developed in September, thereby giving market forwards time to mean-revert.

Official Forward Price Curve (OFPC) Components

- The OFPC is comprised of three components:
  - The first 37 months (inclusive of the "BOM" balance of month) reflect electricity & natural gas forwards, that were "locked down" on Dec 31, 2018.
  - Months 38 through 49 are an average of the preceding year's month-on-month forward prices with the following year's month-on-month fundamentals price (described in the bullet below)
  - From month 50 through the year 2040, a fundamentals - based natural gas price forecast is used to generate a fundamentals - based electricity price forecast, via Aurora.
  - This presentation summarizes the fully blended OFPC dated Dec 31, 2018 and documents the assumptions used in Aurora.

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Aurora Simulation Details

- Aurora version 13.1.1001 was used for the study in conjunction with database: US_Canada_DB_2017_v2.
- The first 37 months of the Aurora electricity price forecast was then supplanted by market forwards, effective Dec 31, 2018 while months 38 – 49 were replaced by blended prices
- All back-up documentation is stored on the Aurora server and in work papers maintained by the market assessment group

Aurora Simulation Details

– Key assumptions, updated by PacifiCorp, as used to produce the Dec 31, 2018, OFPC were:
  - New entrants (retirements)
  - California RPS requirement
  - Natural gas price forecasts

Forward Price Curve Results

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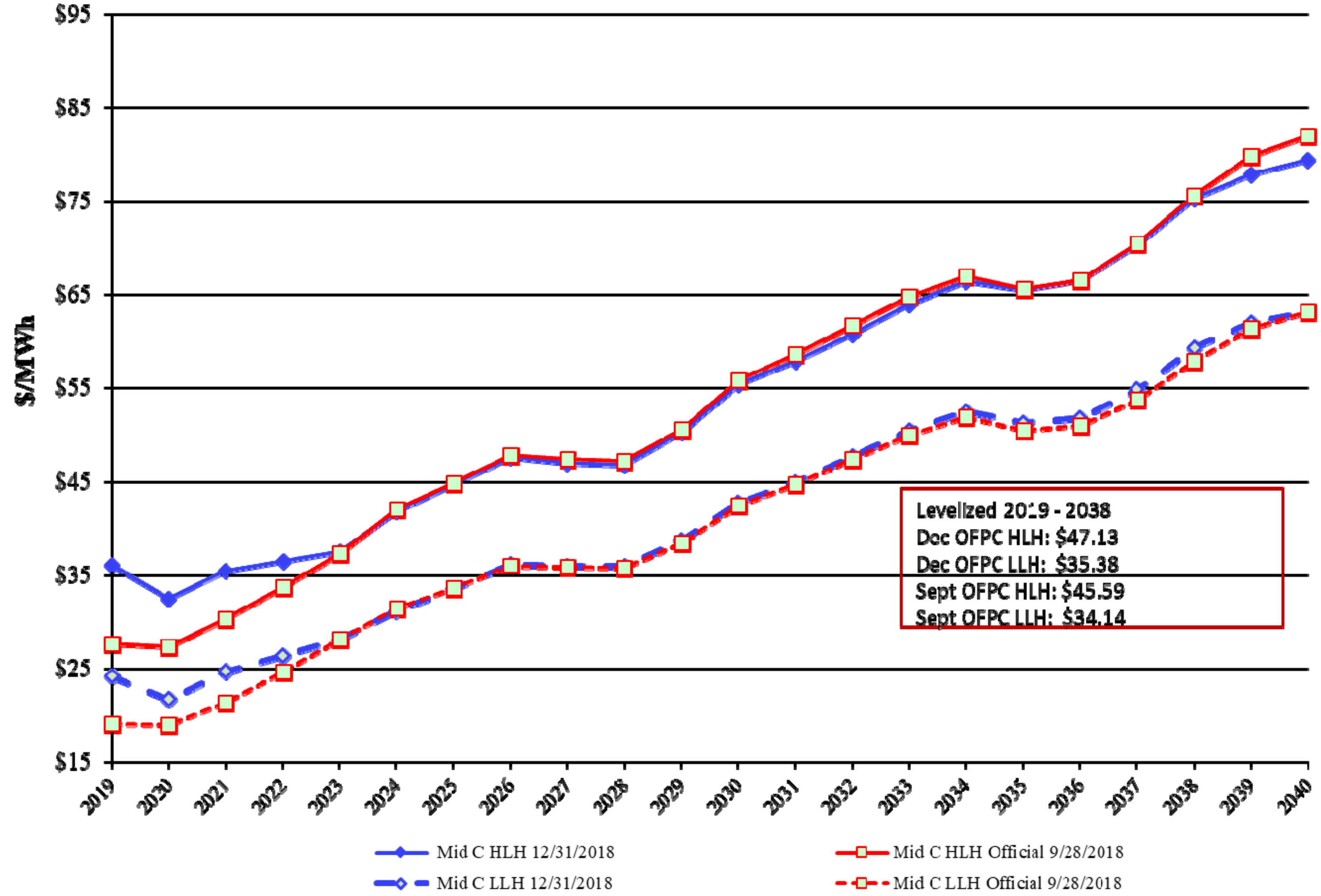
Official Mid-Columbia Electricity Prices



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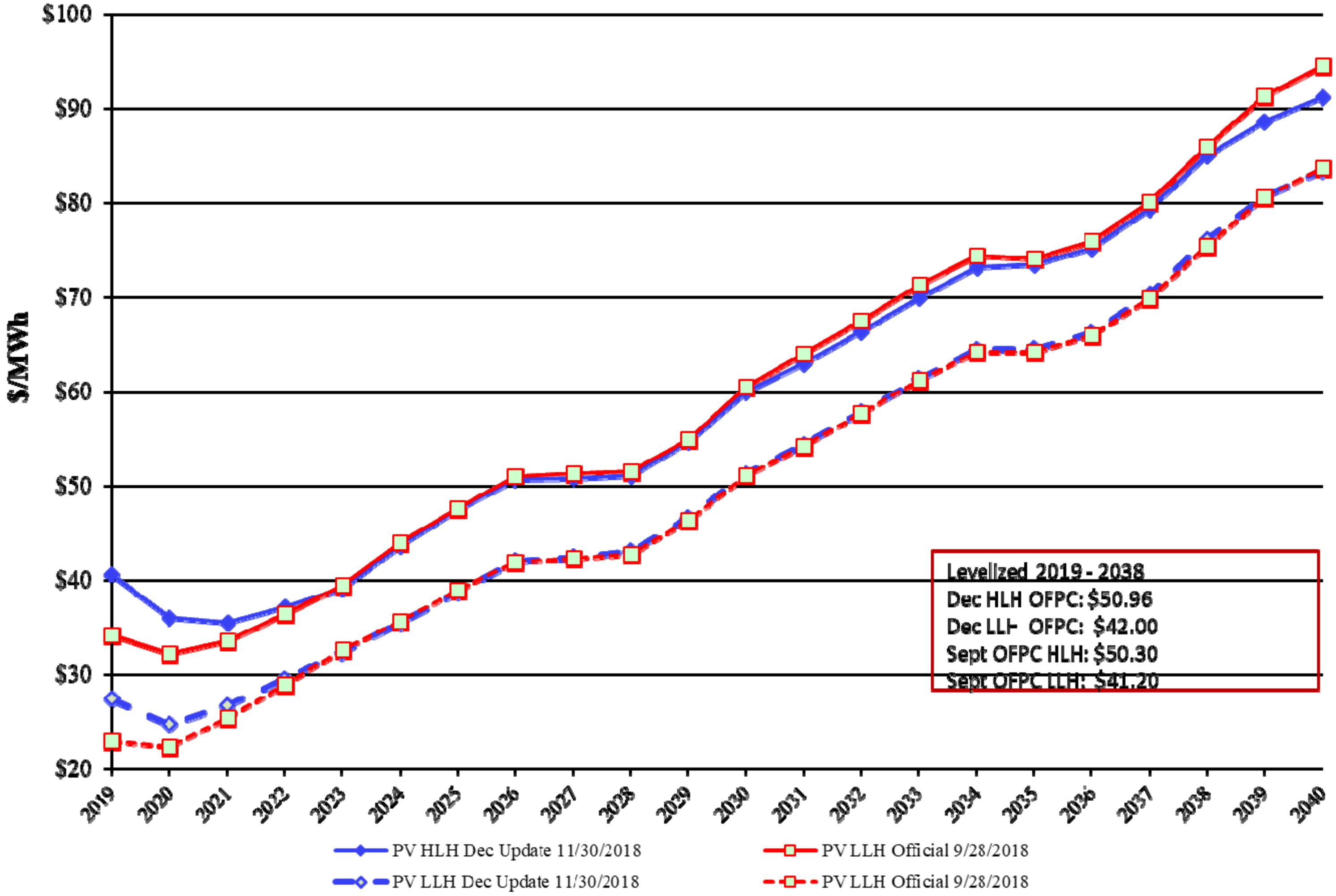
Official Palo Verde Electricity Prices



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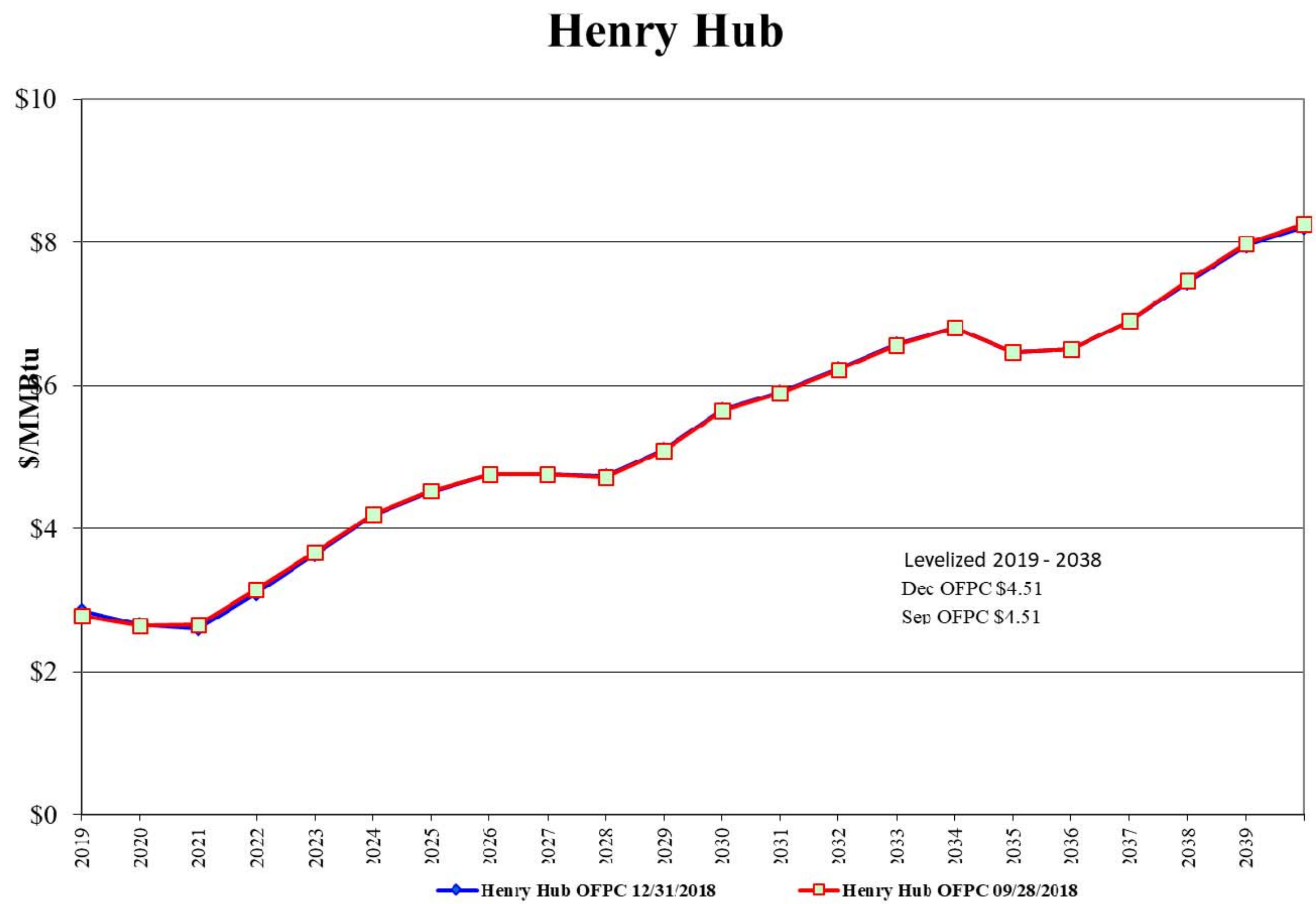
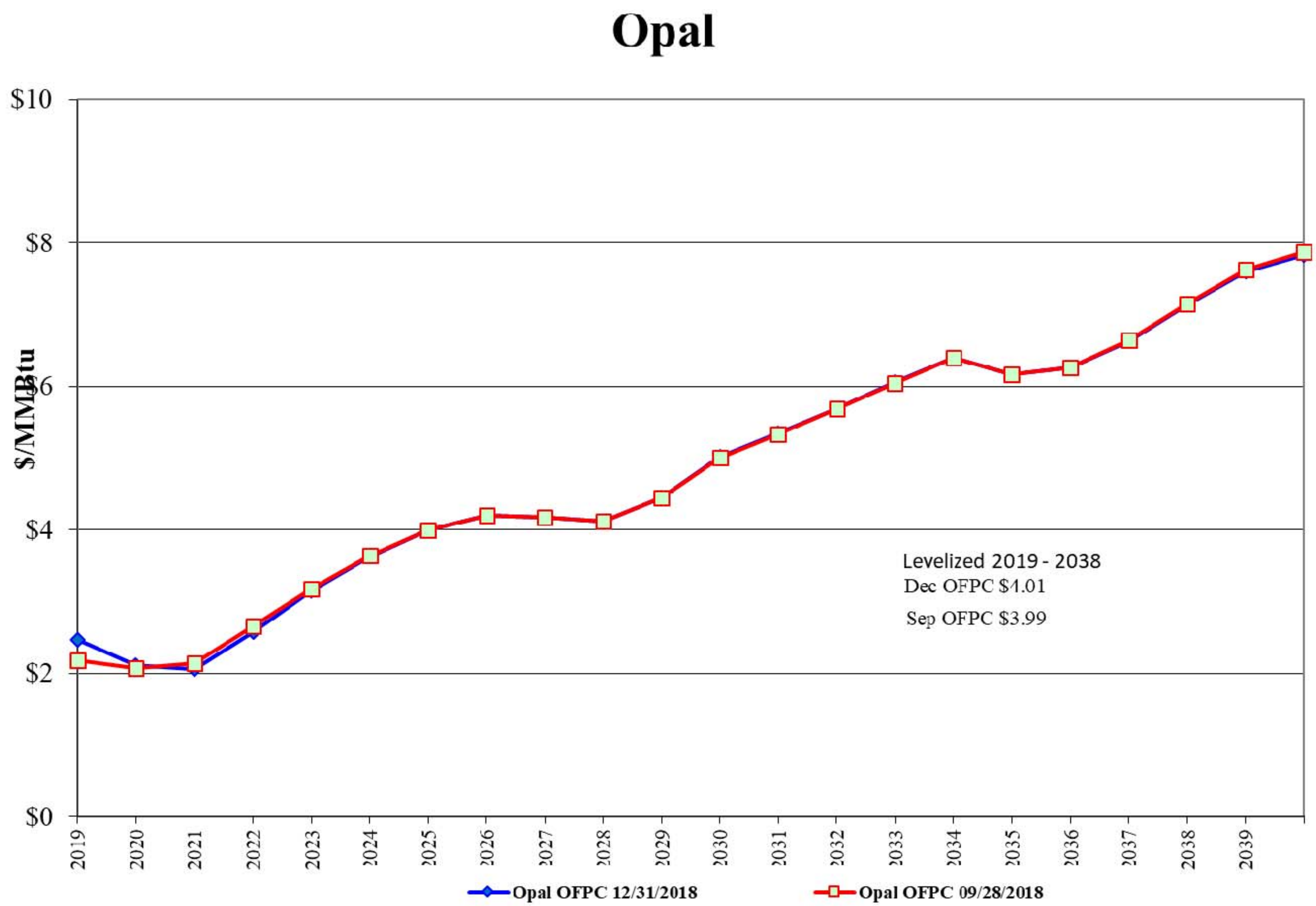
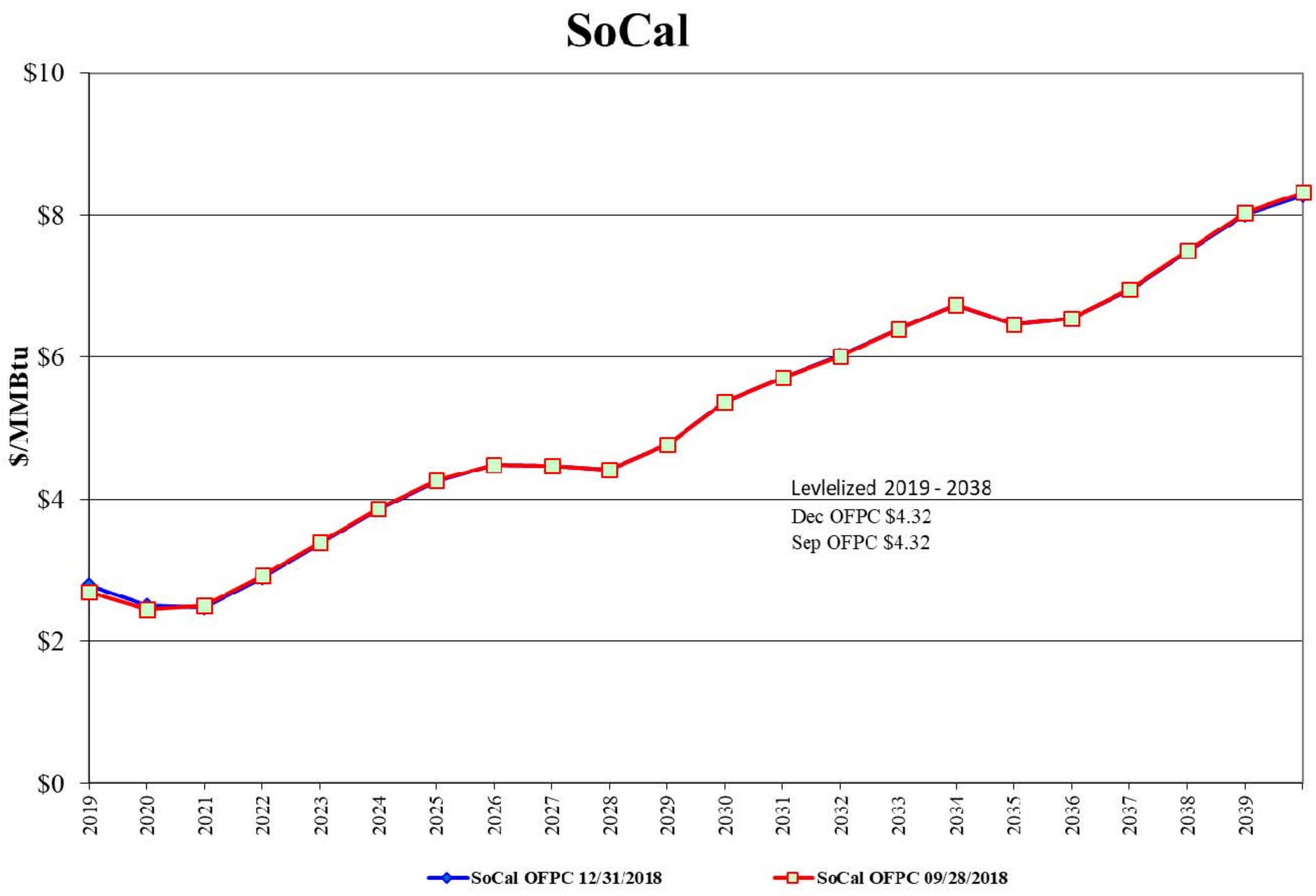
Official Henry Hub Natural Gas Prices



Official Opal Natural Gas Prices



Official SoCal Natural Gas Prices



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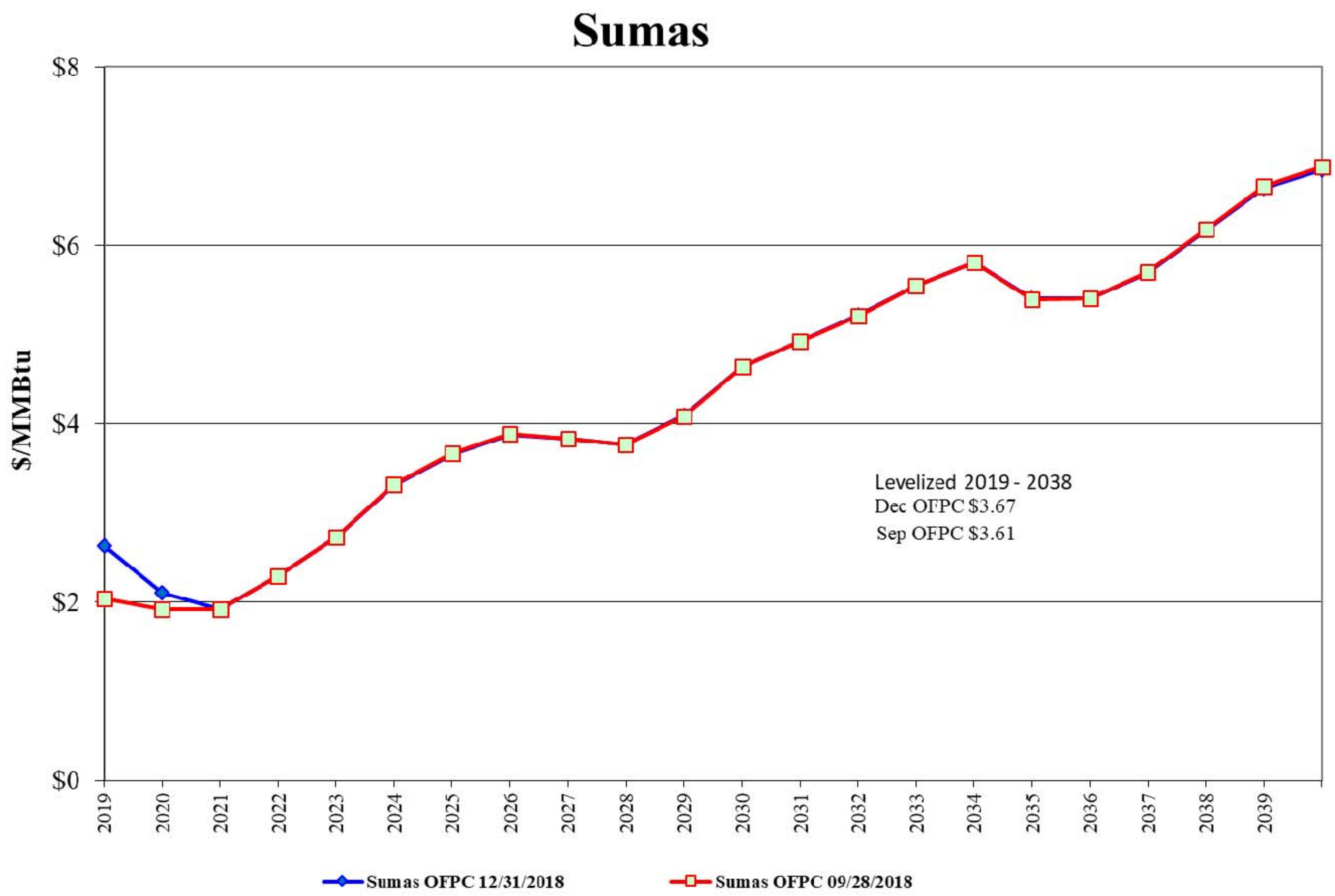
Official Sumas Natural Gas Prices



Aurora Assumptions
Natural Gas and Oil Prices

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Natural Gas Prices in Aurora: Updated

- The market assessment group routinely reviews reputable third party gas price forecasts to ensure the most current data are used in the OFPC.
- A range of factors are considered when adopting a forecast or combination of forecasts for use in PacifiCorp's OFPC.
  - Underlying fundamental assumptions (i.e. gas balances)
  - Documentation (i.e. rationale behind assumptions)
  - Peer-to-peer price comparisons (i.e. outliers)
  - Forecast release date (i.e. is the forecast outdated?)
  - Forecast horizon (i.e. how far are prices projected?)

- The first 37 months come directly from market forwards for the last trading day of the quarter. Months 38- 49 are a blend of market forwards with Aurora fundamentals.

- Months 50 through December 2040 are based upon an expert third-party long-term natural gas price forecast, issued August 2018.
  - Projected prices for all western points of delivery are used through 2040
  - The third party natural gas price forecast is adjusted to nominal dollars using PacifiCorp's current inflation rates.

- The Aurora electricity price forecast utilizes a pure fundamentals-based gas price forecast for months 50 through December 2040.

Natural Gas Assignments: **No Update**

Aurora	Assigned Gas Hub
Alberta	AECO
Palo Verde	Southern California Border
Baja Mexico	Southern California Border
British Columbia	Sumas
Montana	AECO
Northern California	PG&E
Southern Nevada (Mead)	Opal
Northern Nevada	Avg. of Malin and Stanfield
Mid-Columbia	Sumas ***or*** Stanfield*
Southern California	Southern California Border
Idaho	Stanfield
Utah	Opal
Colorado	Opal
Four Corners	San Juan
Wyoming	Opal
California Oregon Border	Malin

*Existing and hardwired units east of the Cascade range are assigned Stanfield, while units west of the Cascade range are assigned Sumas. Endogenous new builds are assigned to Stanfield or Sumas depending on the specific Aurora area where the endogenous unit is located.

Natural Gas Pipeline Tariffs: No Update

WECC Region	Gas Hub	Pipeline	Transportation Commodity $/mmbtu	Capacity Reservation $/mmbtu	Fuel Reimbursement %	Fuel Reimbursement	Sales Tax	Consumption Tax	Business Tax
Alberta	AECO	Nova	$ 0.24651	$ 0.24651	0.00%	1.0000	1.00000	1.00000	1.00000
Baja Mexico	Southern California Border	SoCal + PGT Baja	$ 0.15616	$ 0.15746	0.85%	1.0086	1.00000	1.00000	1.00000
BC Hydro	Sumas	Westcoast Energy	$ -	$ -	0.00%	1.0000	1.00000	1.00000	1.00000
California Oregon Border	Malin	Gas Transmission Northwest (GTN)	$ 0.00021	$ 0.00151	0.042%	1.0004	1.00000	1.00000	1.00000
Colorado	Opal	Colorado Interstate	$ 0.01700	$ 0.01830	0.46%	1.0046	1.00000	1.00000	1.00000
New Mexico / Four Corners	San Juan	El Paso New Mexico	$ 0.02350	$ 0.02480	2.34%	1.0240	1.00000	1.00000	1.00000
Idaho	Stanfield	Northwest Pipeline / Williams	$ 0.03000	$ 0.03130	1.19%	1.0120	1.00000	1.00000	1.00000
Southern Nevada (Mead)	Opal	Kern	$ 0.00440	$ 0.00570	0.00%	1.0000	1.00000	1.00000	1.00000
Mid-C (East OR)	Stanfield	Northwest Pipeline / Williams	$ 0.03000	$ 0.03130	1.19%	1.0120	1.00000	1.00000	1.00000
Mid-C (West OR)	Sumas	Northwest Pipeline / Williams	$ 0.03000	$ 0.03130	1.19%	1.0120	1.00000	1.00000	1.00000
Mid-C (East WA)	Stanfield	Northwest Pipeline / Williams	$ 0.03000	$ 0.03130	1.19%	1.0120	1.00000	1.03852	1.00000
Mid-C (West WA)	Sumas	Northwest Pipeline / Williams	$ 0.03000	$ 0.03130	1.19%	1.0120	1.00000	1.03852	1.00000
Montana	AECO	Nova + Northwest Energy	$ 0.24994	$ 0.24994	2.46%	1.0252	1.00000	1.00000	1.00000
Northern Nevada	Average of Malin and Stanfield	Average of Williams/Paiute, Tuscarora	$ 0.01655	$ 0.01785	3.10%	1.0319	1.00000	1.00000	1.00000
Northern California	PG&E	PG&E	$ 0.01070	$ 0.01200	0.10%	1.0010	1.01407	1.00000	1.00000
Arizona / Palo Verde	Southern California Border	El Paso Arizona	$ 0.03180	$ 0.03310	2.34%	1.0240	1.00000	1.00000	1.00000
Southern California	Southern California Border	SoCal	$ 0.15550	$ 0.15680	0.118%	1.0012	1.01942	1.00000	1.00000
Utah	Opal	Questar	$ 0.00267	$ 0.00397	1.37%	1.0139	1.00000	1.00000	1.00000
Wyoming	Opal	Average of Colorado Interstate, Wyoming Interstate, Tallgrass	$ 0.00843	$ 0.00973	0.66%	1.0066	1.00000	1.00000	1.00000

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Aurora Assumptions
Hardwired Resources

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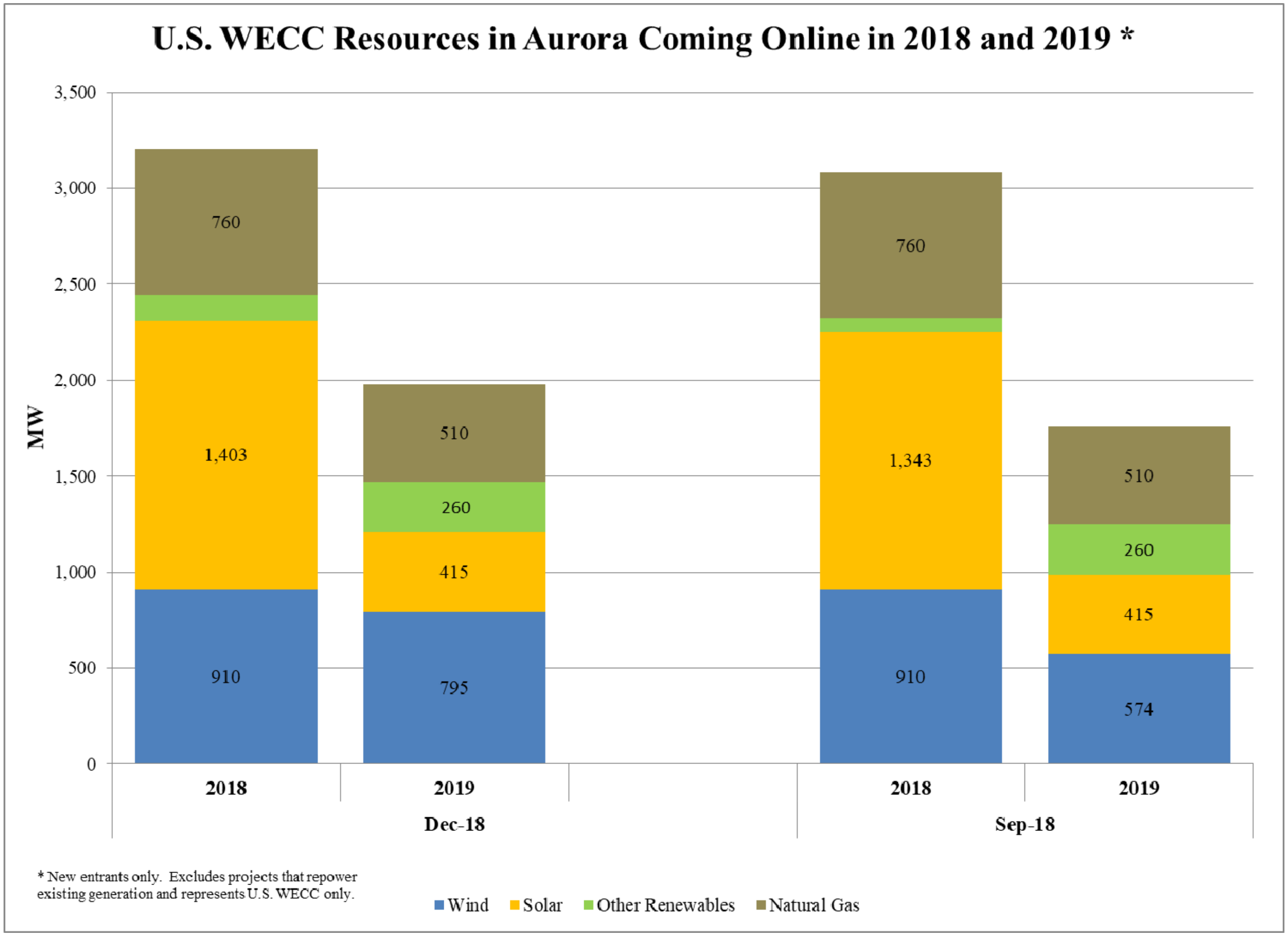
Hardwired New Resources

- The market assessment group tracks the status of new electric generating plants across the WECC to ensure the latest data are incorporated into the price forecast
- Units that are under construction or far into advanced development, such that the commercial on-line date can be forecasted with confidence, are hardwired into Aurora.
- At the same time, units are removed from Aurora when the latest data suggests their development has stalled or when planned retirements are announced
- New entrant (retirement) source data includes SNL Financial and online project research.

Assumptions: U.S. WECC Resources in Aurora Coming Online in 2018 and 2019



Aurora Assumptions

New Resources

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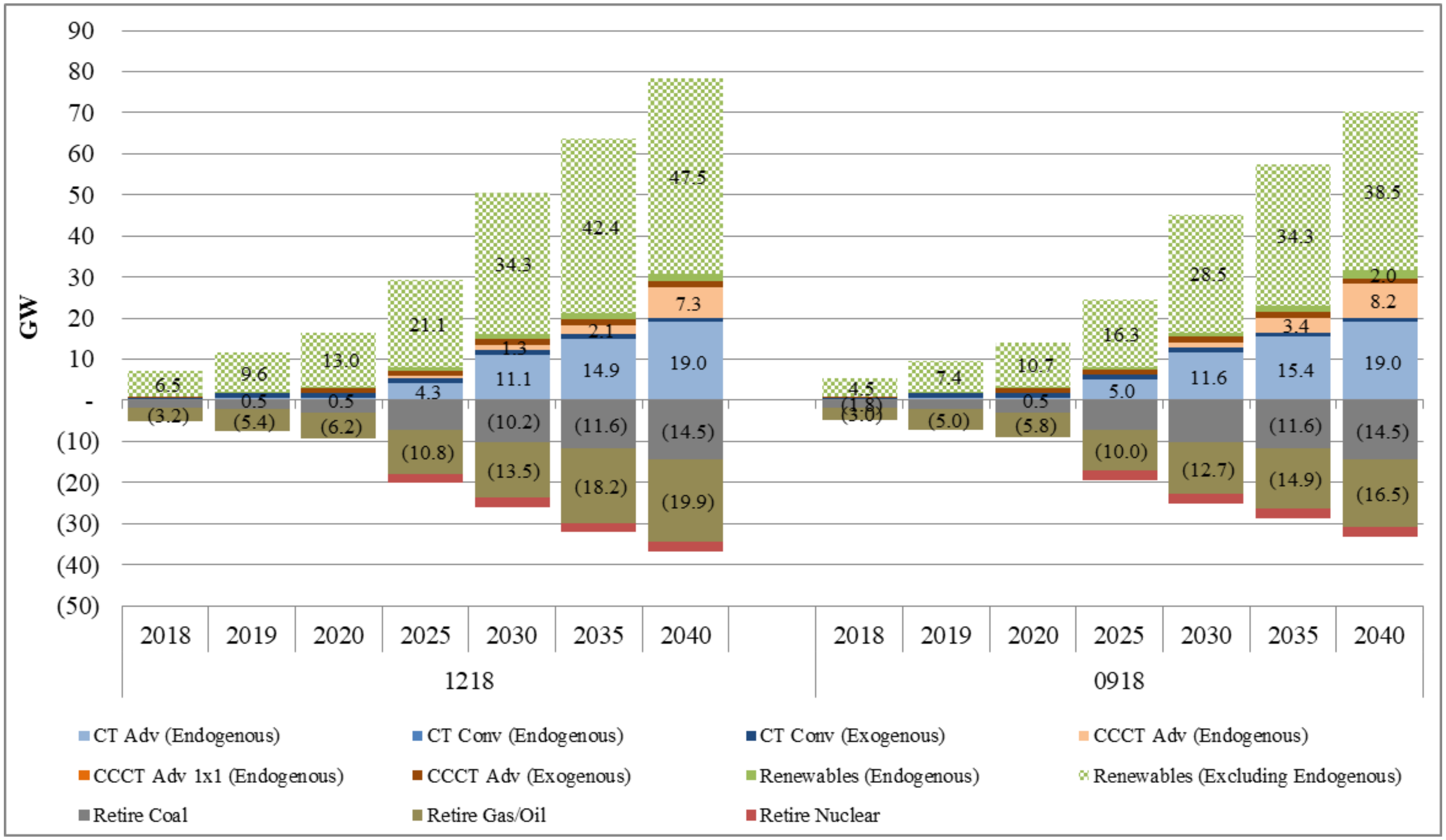
Resource Addition Methodology: **No Update**

- The Aurora model's endogenous build logic is used for generic new gas, solar, and wind resource additions.
- Resources needed to satisfy states' renewable portfolio standard requirements are determined outside of Aurora and then "hardwired" into Aurora.
- Once all new hardwired resources are entered into Aurora, the model utilizes its endogenous build logic to fill in any remaining resource "gaps" consistent with regional planning and operating requirements.

Assumptions: Total WECC Resource Builds and Retirements



* Endogenous units are added by Aurora as part of its optimization.
Non-endogenous units, such as new entrants or RPS –determined resources are user added.

Renewable Portfolio Standards (RPS) Addition Methodology:

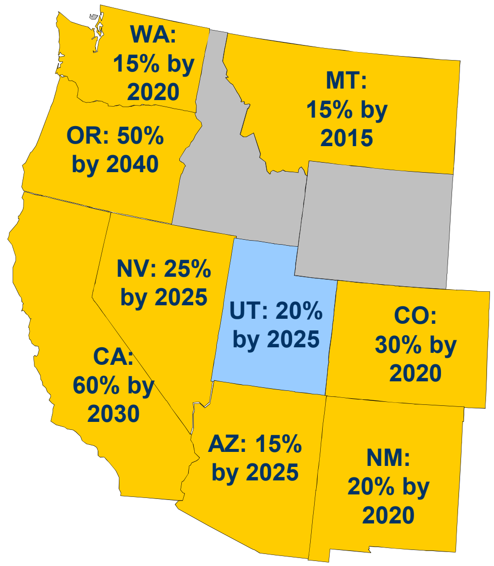
– U.S. WECC needs are developed through an evaluation of state-specific RPS requirements and the means to meet those requirements.

– SB 100 was signed into law on September 10, 2018, raising the California RPS requirement to 60% by 2030. The amount of additional renewable resources needed to meet the California RPS requirement was calculated from data gathered from the CPUC RESOLVE model and EIA.

– Resources needed to meet RPS requirements are exogenously determined and input to Aurora.

– RPS resource options include the following
  - Wind
  - Geothermal
  - Biomass
  - Solar photovoltaic

Renewable Portfolio Standards – No Update



= States with renewable portfolio *standard*

= States with renewable portfolio *goals*

- States with renewable portfolio *standards*, which generally are enforceable, are modeled in Aurora. State *goals* are also modeled in Aurora. No Federal renewable portfolio standards are modeled in Aurora.
- Some states have targets defined by tiers or classes. In such instances, Tier II or Class II requirements (typically covering existing resources, hydro, CHP, and in some cases, energy efficiency) are not explicitly modeled.

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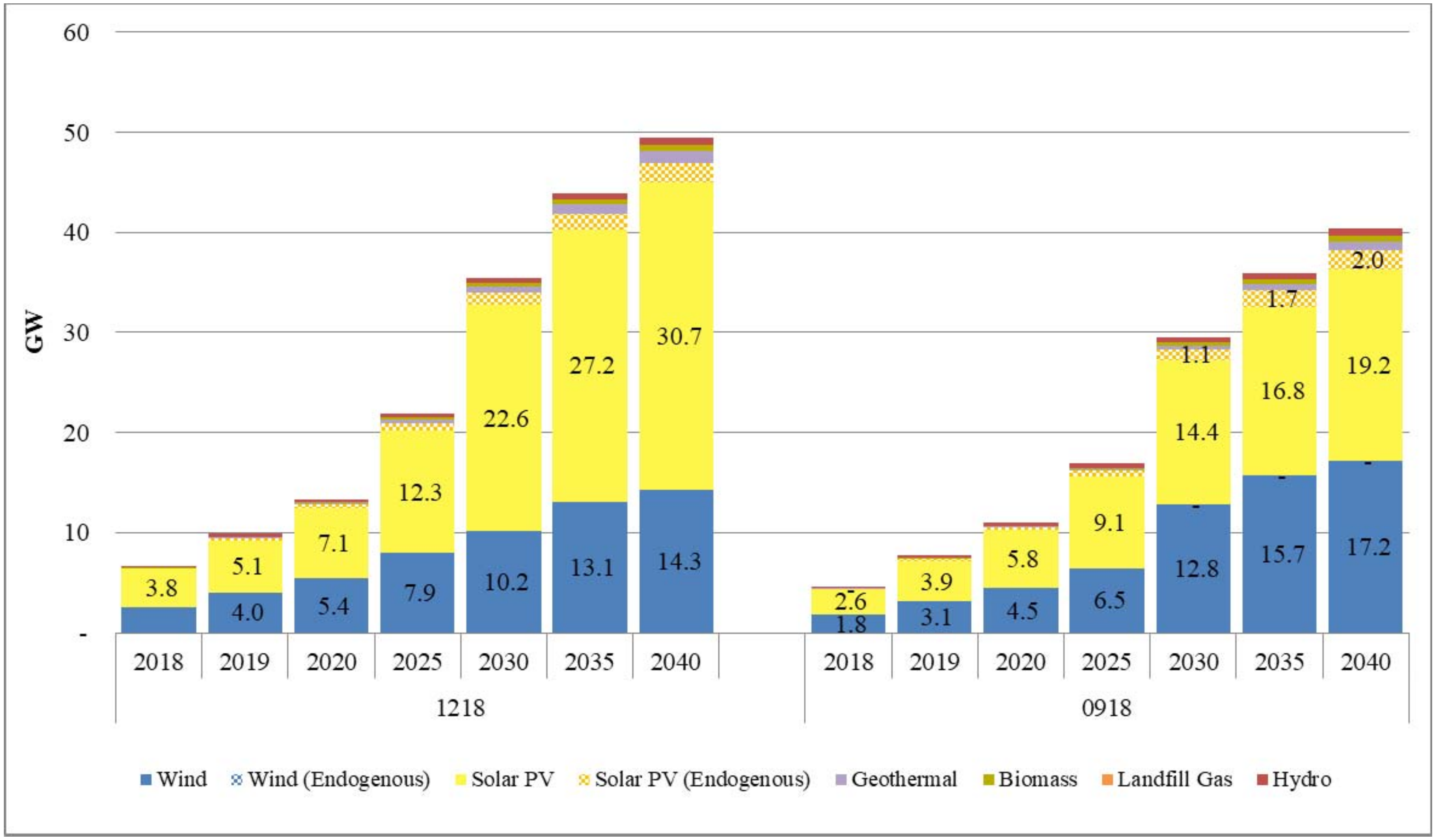
Assumptions: Total WECC Renewable Resource Builds



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Aurora Assumptions
Hydro

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Treatment of Hydro Generation in Aurora

- WECC hydro is currently modeled as a mixture of run-of-river, shaped, and pumped storage.
- Shaped hydro is specified by average monthly generation and the ability to shift output during peak loads.
- Historical hydro 80-water years table was updated to reflect the latest available assumptions from the Northwest Power and Conservation Council

Hydro Generation

- Aurora's average monthly generation profile reflects historic hydro generation in WECC reasonably well.
- Hydro generation was updated with the latest data on new units:
  - Hardwired new resource additions and upgrades
  - Change in status
- Over the forecast, annual hydro production averages 262,939 GWh
- Aurora does not subtract hydro from load but supports a flexible modeling framework that allows the user to shape hydro to follow load.

Aurora Assumptions

Environmental

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State & Federal CO_2: No Update

California cap-and-trade policy assumptions in Aurora

- In the absence of a Federal CO_2 tax, California CO_2 is assumed to continue post 2030. July 25, 2017 Governor Jerry Brown signed into law the extension of California's existing cap-and-trade program to 2030, per Assembly Bill 398.
- Aurora's cap-and-trade prices come from an third-party expert's forecast of California Carbon Allowance (CCA) prices.
- All fossil-fired generating units operating within California generate emissions consistent with the CO_2 content of the fuel and the unit's heat rate
- For instance, a combined cycle plant with a 7,500 Btu/kWh heat rate burning natural gas, with a CO_2 content of 118 lb/MMBtu, would produce 0.44 tons of CO_2 emissions for each MWh generated
- The assumed California CO_2 allowance price is modeled as a dispatch cost adder and applied to plant CO_2 emissions.

October 10, 2017 EPA Chief Scott Pruitt signed a proposal for EPA to withdraw its Clean Power Plan, without an immediate replacement.

- The CPP is no longer assumed and no Federal CO2 program is currently modeled in Aurora.

Aurora Assumptions
Macroeconomic and Power Market Drivers

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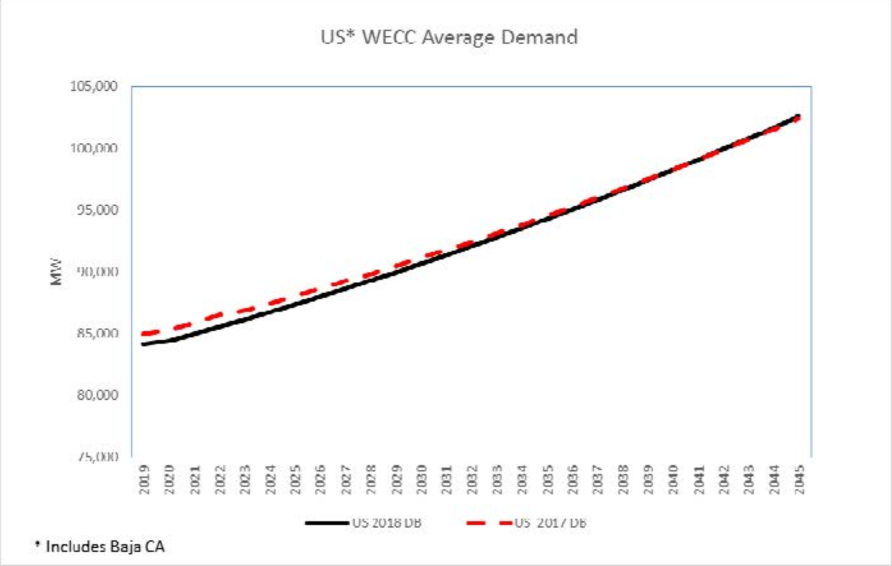
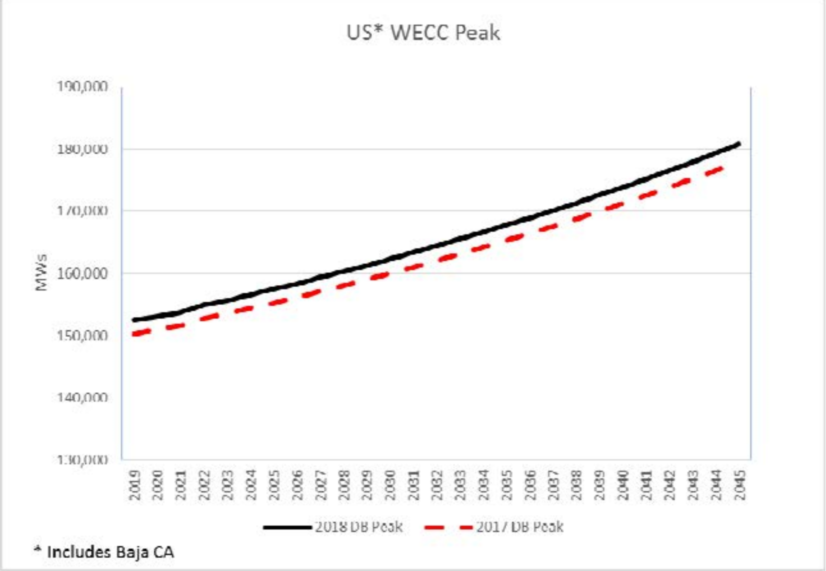
WECC Loads – No Update

- Loads reflect forecasted peaks and energy in Aurora's January 2018 database release. Vis-à-vis the 2017 database release for U.S. WECC :
  - Yearly energy growth for 2019 through 2040 is down .5%.
  - Yearly peak demand growth for 2019 through 2040 is up 1.5%.





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Reserves: No Update

- Long-term resource adequacy is modeled in Aurora through the implementation of planning reserve margins. Planning reserve margins are specified annually as the percentage of reliable capacity required above forecasted peak demand.
- Planning reserve margins are specified for eight distinct planning areas (shown on the next slide). Northern California and Southern California participate in reserve sharing.
- Both operating reserves and planning reserve margins reflect reserve needs as necessitated by the changes in variable generation.
- Operating reserve levels were determined by the relationship between operating reserves, and load and wind capacities as published in PacifiCorp's 2014 wind integration study. The relationship was then applied across WECC.
- Planning reserve margins are assumed to be no lower than operating reserves plus 4% to cover expected forced outages of combined cycle combustion turbine resources.

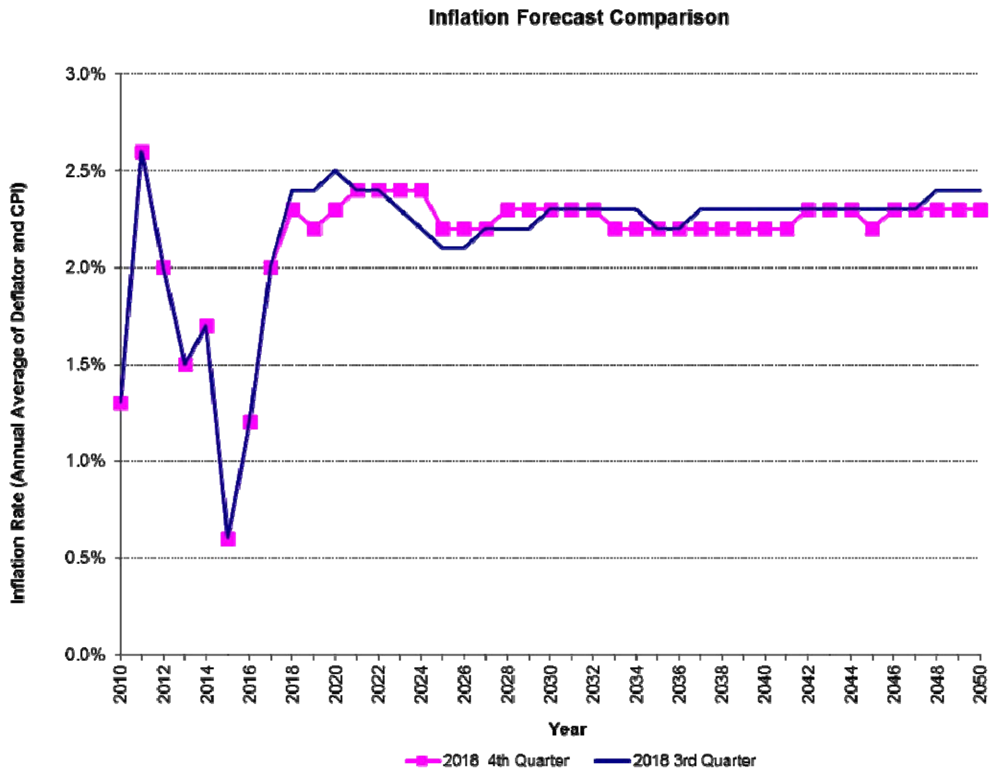
Aurora Reserve Margin Planning Areas: No Update

Zone	Reserve Margin Planning Area
WECC_CA_North	Northern California
WECC_CA_PG&E	Northern California
WECC_CA-SCE	Southern California & Baja
WECC_CA-South	Southern California & Baja
WECC_Alberta	Northwest Power Pool _ Alberta
WECC_BritishColumbia	Northwest Power Pool _ British Columbia
WECC_PNW-Olympia	Northwest Power Pool _U.S.
WECC_PNW-PACWSouth	Northwest Power Pool _U.S.
WECC_PNW-PugetSoundNorth	Northwest Power Pool _U.S.
WECC_PNW_PugetSoundE	Northwest Power Pool _U.S.
WECC_PNW_SeattleCL	Northwest Power Pool _U.S.
WECC_PNW_TacomaPower	Northwest Power Pool _U.S.
WECC_PNW_GrantCountyPUD	Northwest Power Pool _U.S.
WECC_PNW_ChelanCountyPUD	Northwest Power Pool _U.S.
WECC_PNW_DouglasCountyPUD	Northwest Power Pool _U.S.
WECC_PNW_Avista	Northwest Power Pool _U.S.
WECC_PNW_PortlandGeneral	Northwest Power Pool _U.S.
WECC_PNW_Bonneville_OR	Northwest Power Pool _U.S.
WECC_PNW_Bonneville_WA	Northwest Power Pool _U.S.
WECC_PNW_Bonneville_IDMT	Northwest Power Pool _U.S.
WECC_NorthwesternMT	Northwest Power Pool _U.S.
WECC_WAPA_UprMO	Northwest Power Pool _U.S.
WECC_VEA	Northwest Power Pool _U.S.
WECC_PNW_PacificorpEastUT	Northwest Power Pool_U.S._BASIN
WECC_NevadaNorth	Northwest Power Pool_U.S._BASIN
WECC_PNW_IdahoPowerTV	Northwest Power Pool_U.S._BASIN
WECC_PNW_IdahoPowerMV	Northwest Power Pool_U.S._BASIN
WECC_PNW_IdahoPowerFE	Northwest Power Pool_U.S._BASIN
WECC_PNW_PacificorpEastID	Northwest Power Pool_U.S._BASIN
WECC_PNW_PacificorpEastWY	Rocky Mountains
WECC_WAPA_WY	Rocky Mountains
WECC_CO	Rocky Mountains
WECC_NevadaSouth	Southwest
WECC_AZ	Southwest
WECC_PublicServiceNM	Southwest
WECC_AZPS	Southwest

Aurora Assumptions
General

Inflation: Updated

- PacifiCorp finance reviews the corporate inflation rate each quarter using data from an expert thirty party.
- Inflation was updated Dec 2018; the previous inflation update was Sept 2018.
- Over the period 2019 through 2038, inflation averages 2.3% — consistent with the Sept 2018 average of 2.3%.



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Outages and Heat Rates: **No Update**

- Forced outage rates for WECC units reflect Aurora's default forced outage rates. These outage rates are currently modeled as derates to unit capacities.
- Aurora includes maintenance cycle (months) and maintenance length (days) for resources greater than 200 MW with the fuel types below:
  - Coal
  - Gas (combined cycles, steam units, and combustion turbines)
  - Nuclear
  - Oil
- Nuclear
  - Refueling outages are scheduled every 18 months (spring and fall) for 33 days for Palo Verde, Diablo Canyon, and Columbia units.
  - Outages reflect Aurora's default as-delivered outage cycles and lengths.
- The primary source for maintenance data is the North American Electric Reliability Council (NERC) Generating Availability Data System (GADS).
- Heat rates for generic gas resources reflect Aurora's default heat rates which were updated based on EIA data.

Variable and Fixed O&M: No Update

– Variable and fixed O&M costs for generic new-build WECC resources (gas units, solar, and wind) were updated to reflect assumptions per Energy Exemplar's January 2018 database release.

2012$		
	Avg. Variable O&M $/MWh	Avg. Fixed O&M $/MW-week
Combined Cycle	$1.80	$550
Single Cycle, Advanced	$9.63	$333
Single Cycle, Conventional	$3.15	$636
Solar, PV	$0	$550
Wind	$0	$1,484

Emission Rates and Pollution Controls: **No Update**

- Emission rates and pollution control equipment installations reflect Aurora's default as-delivered data.
  - SO_2, NOx, and CO_2 emissions are sourced from the Environmental Protection Agency (EPA) |*Continuous Emission Monitoring System 2011*.
  - Hg (mercury) emissions are sourced from EPA estimates using the Integrated Planning Model.

Curtailable Load: **No Update**

- Curtailable loads are included in Aurora as high-cost dispatchable resources. The default values for demand side curtailment are in tiers that differ by cost and size. These tiers are meant to promote a reasonable dispatch and set of prices during supply-shortage conditions.
- Load curtailment cost-tier considerations include:
  - Cost for curtailment units is sufficiently high to promote new resource options to be selected in long-term capacity expansion runs.
  - The merit order of curtailment units should be above the highest cost dispatchable resource (but below the dispatch penalty of a commitment-type unit that has been decommitted or not committed).
  - Cost for curtailment units should be high enough to not require a re-adjustment of curtailment costs given typical fuel price increases over time.
- The amount of curtailable load in Aurora differs by area to reflect the load and resource balance of each area.
- Curtailment tiers range in price from $47.46/ MWh to $527.42/MWh (2012$).

Blending and Scaling: No Update

– The Dec 31, 2018 official forward price curve (OFPC) is comprised of 1 month of BOM (balance of market) and 36 months of market forwards followed by a year of blended prices that segues into a pure fundamentals forecast.
– The blended period begins in month 38 and ends in month 49. As such, prices are calculated as an average of the preceding year's month-on-month forward prices with the following year's month-on-month fundamentals price
– Hourly prices are produced using hourly scalars, updated quarterly, and applied to monthly prices.

	Market[1]	Aurora
Through Month 37 (Jan 2022)	100%	0%
Months 38 – 49 (Feb 2022 – 2023)[2]	50%	50%
Month 50 (Feb 2023 and	0%	100%

1. The official forward price curve uses market data as of Dec 31, 2018
2. Months 38- 49 are an average of market and Aurora: for example, month 38 = (market month 26 + Aurora month 50)/2

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Gas Price Forecast Comparison

	OFPC December 2018 West Side Gas	OFPC March 2018 West Side Gas	Change	% Change
2030	5.00	5.10	(0.10)	-2%
2031	5.32	5.09	0.23	5%
2032	5.64	5.48	0.16	3%
2033	5.96	5.78	0.18	3%
2034	6.27	5.67	0.60	11%
2035	5.94	5.82	0.12	2%