PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 20, 2018

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: UM 1729—Standard Avoided Cost Purchases from Eligible Qualifying Facilities – Compliance Filing

In compliance with Order No. 18-273 (the Order), PacifiCorp d/b/a Pacific Power submits the enclosed standard non-renewable and standard renewable avoided cost information (formerly known as Schedule 37) for purchases from eligible qualifying facilities. Per the Order, the effective date of the standard non-renewable pricing is July 18, 2018 and the effective date of the standard renewable pricing will be July 24, 2018.[1]

The enclosed standard renewable avoided cost prices comply with the Order by including a renewable deficiency period capacity payment beginning in 2021. The resulting standard avoided cost pricing is summarized in the table below on a 15–year levelized, $/MWh basis starting in 2019 and includes a comparison with current prices.

	Non-Renewable			Renewable			Renewable vs. Non-Renewable	
	Current	per Order	Change	Current	per Order	Change	Current	per Order
Baseload	$35.89	$37.32	$1.43	$47.72	$41.05	($6.67)	$11.83	$3.73
Wind	$30.61	$34.60	$3.99	$39.83	$28.98	($10.85)	$9.22	($5.62)
Fixed Solar	$38.73	$41.59	$2.86	$47.47	$50.26	$2.79	$8.74	$8.67
Tracking Solar	$38.62	$41.83	$3.21	$48.08	$52.33	$4.25	$9.46	$10.50

PacifiCorp notes that, for wind resources, renewable avoided cost prices are lower than the non-renewable avoided cost prices, which illustrates the significance of the company's Motion for Emergency Interim Relief filed in this docket on April 26, 2018. Without the relief sought, wind qualifying facilities may choose the higher non-renewable avoided cost prices while still retaining the related renewable energy certificates. PacifiCorp urges consideration of its Motion for Emergency Interim Relief in light of the continuing need to address the illogical outcome described above.

In support of this filing, PacifiCorp submits Appendix 1- Avoided Cost Study and Appendix 2- Method Write-up and Minimum Filing Requirements. Also provided are the supporting documentation in both "pdf" and original formats.

[1] *In the Matter of PacifiCorp dba Pacific Power Updates Standard Avoided Cost Purchases from Eligible Qualifying Facilities,* Docket No. UM 1729, Order No. 18-273 at 1 (July 18, 2018).

Please direct any informal inquiries about this filing to Natasha Siores, Manager, Regulatory Affairs, at (503) 813-6583.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

Revised Tariff Sheets

PACIFIC POWER
PROPOSED TARIFF CHANGES TO STANDARD RATES

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – JULY 2018

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)

(C)

Deliveries	Base Load QF (1,3)		Wind QF (2,3)	
During Calendar Year	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)
2018	2.37	1.65	2.31	1.59
2019	2.46	1.80	2.40	1.74
2020	2.69	2.08	2.63	2.02
2021	3.03	2.39	2.97	2.33
2022	3.21	2.55	3.15	2.48
2023	3.37	2.73	3.30	2.66
2024	3.60	2.97	3.53	2.90
2025	3.89	3.25	3.82	3.18
2026	4.01	3.38	3.93	3.30
2027	4.13	3.49	4.05	3.41
2028	4.31	3.70	4.23	3.62
2029	4.69	4.06	4.61	3.98
2030	7.32	4.41	5.20	4.32
2031	7.40	4.42	5.23	4.34
2032	7.73	4.70	5.52	4.61
2033	8.01	4.91	5.76	4.83
2034	8.03	4.87	5.73	4.78
2035	8.22	4.99	5.87	4.90
2036	8.28	4.98	5.88	4.89

(C)

(continued)

Avoided Cost Prices (Continued)

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

Deliveries During Calendar Year	Fixed Solar QF (2,3) On-Peak Energy Price	Fixed Solar QF (2,3) Off-Peak Energy Price	Tracking Solar QF (2,3) On-Peak Energy Price	Tracking Solar QF (2,3) Off-Peak Energy Price
	(e)	(f)	(g)	(h)
2018	2.31	1.59	2.31	1.59
2019	2.40	1.74	2.40	1.74
2020	2.63	2.01	2.63	2.01
2021	2.97	2.32	2.97	2.32
2022	3.14	2.48	3.14	2.48
2023	3.30	2.66	3.30	2.66
2024	3.53	2.89	3.53	2.89
2025	3.81	3.17	3.81	3.17
2026	3.93	3.30	3.93	3.30
2027	4.05	3.41	4.05	3.41
2028	4.23	3.62	4.23	3.62
2029	4.61	3.97	4.61	3.97
2030	8.52	4.32	8.73	4.32
2031	8.63	4.34	8.84	4.34
2032	8.99	4.61	9.20	4.61
2033	9.29	4.82	9.51	4.82
2034	9.34	4.78	9.56	4.78
2035	9.55	4.90	9.78	4.90
2036	9.64	4.89	9.87	4.89

(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.

(C)

(continued)

Avoided Cost Prices (Continued)

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

(C)

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)
2018	2.37	1.65	2.31	1.59
2019	2.46	1.80	2.40	1.74
2020	2.69	2.08	2.63	2.02
2021	5.20	2.53	2.89	2.46
2022	5.32	2.61	2.95	2.54
2023	5.43	2.69	3.01	2.62
2024	5.53	2.79	3.05	2.72
2025	5.63	2.89	3.09	2.81
2026	5.75	2.96	3.15	2.89
2027	5.88	3.03	3.22	2.96
2028	5.99	3.12	3.28	3.04
2029	6.11	3.20	3.34	3.12
2030	6.24	3.28	3.41	3.20
2031	6.36	3.36	3.47	3.27
2032	6.49	3.43	3.54	3.35
2033	6.62	3.52	3.60	3.43
2034	6.76	3.59	3.68	3.50
2035	6.89	3.67	3.75	3.58
2036	7.02	3.75	3.82	3.66

(C)

(continued)

Avoided Cost Prices (continued)

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

(C)

Deliveries During Calendar Year	Fixed Solar QF (1,2,3)		Tracking Solar QF (1,2,3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(e)	(f)	(g)	(h)
2018	2.31	1.59	2.31	1.59
2019	2.40	1.74	2.40	1.74
2020	2.63	2.01	2.63	2.01
2021	5.55	2.46	5.85	2.46
2022	5.68	2.54	5.99	2.54
2023	5.80	2.62	6.11	2.62
2024	5.91	2.72	6.23	2.72
2025	6.02	2.81	6.35	2.81
2026	6.15	2.89	6.48	2.89
2027	6.28	2.95	6.62	2.95
2028	6.41	3.03	6.76	3.03
2029	6.53	3.12	6.89	3.12
2030	6.67	3.19	7.03	3.19
2031	6.80	3.27	7.17	3.27
2032	6.94	3.34	7.32	3.34
2033	7.08	3.42	7.47	3.42
2034	7.22	3.50	7.62	3.50
2035	7.37	3.58	7.77	3.58
2036	7.51	3.65	7.92	3.65

(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). (C)

(continued)

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – JULY 2018

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)
2018	Market Based Prices 2018 through 2029					$23.67	$16.52
2019						$24.61	$17.98
2020						$26.94	$20.78
2021						$30.32	$23.90
2022						$32.13	$25.50
2023						$33.69	$27.31
2024						$36.04	$29.66
2025						$38.87	$32.48
2026						$40.07	$33.76
2027						$41.29	$34.90
2028						$43.06	$37.00
2029						$46.90	$40.55
2030	$142.88	$44.06	100.0%	142.88	$29.10	$73.16	$44.06
2031	$145.92	$44.24	100.0%	145.92	$29.72	$73.96	$44.24
2032	$148.97	$46.98	100.0%	148.97	$30.34	$77.32	$46.98
2033	$152.06	$49.15	100.0%	152.06	$30.97	$80.12	$49.15
2034	$155.20	$48.69	100.0%	155.20	$31.61	$80.31	$48.69
2035	$158.39	$49.91	100.0%	158.39	$32.26	$82.17	$49.91
2036	$161.60	$49.84	100.0%	161.60	$32.92	$82.76	$49.84

(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)
2018						$23.08	$15.93
2019	Market Based Prices					$24.01	$17.38
2020	2018 through 2029					$26.32	$20.16
2021	less Wind Integration (2)					$29.68	$23.26
2022						$31.47	$24.84
2023						$33.01	$26.63
2024						$35.34	$28.96
2025						$38.15	$31.76
2026						$39.33	$33.02
2027						$40.53	$34.14
2028						$42.28	$36.22
2029						$46.10	$39.75
2030	$142.88	$44.06	11.8%	16.83	$8.72	$51.96	$43.24
2031	$145.92	$44.24	11.8%	17.18	$8.91	$52.30	$43.40
2032	$148.97	$46.98	11.8%	17.54	$9.09	$55.21	$46.12
2033	$152.06	$49.15	11.8%	17.91	$9.28	$57.55	$48.27
2034	$155.20	$48.69	11.8%	18.28	$9.47	$57.27	$47.79
2035	$158.39	$49.91	11.8%	18.65	$9.67	$58.65	$48.99
2036	$161.60	$49.84	11.8%	19.03	$9.86	$58.76	$48.90

(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)
2018						$23.05	$15.90
2019	Market Based Prices 2018 through 2029					$23.98	$17.35
2020						$26.29	$20.13
2021						$29.65	$23.23
2022						$31.44	$24.81
2023						$32.98	$26.60
2024						$35.31	$28.93
2025						$38.12	$31.73
2026						$39.30	$32.99
2027						$40.50	$34.11
2028						$42.25	$36.19
2029						$46.07	$39.72
2030	$142.88	$44.06	53.86%	$76.96	$42.00	$85.20	$43.21
2031	$145.92	$44.24	53.86%	$78.59	$42.89	$86.26	$43.37
2032	$148.97	$46.98	53.86%	$80.24	$43.79	$89.88	$46.09
2033	$152.06	$49.15	53.86%	$81.90	$44.69	$92.93	$48.24
2034	$155.20	$48.69	53.86%	$83.59	$45.62	$93.38	$47.76
2035	$158.39	$49.91	53.86%	$85.31	$46.56	$95.51	$48.96
2036	$161.60	$49.84	53.86%	$87.04	$47.50	$96.37	$48.87

(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)
2018	Market Based Prices 2018 through 2029					$23.05	$15.90
2019						$23.98	$17.35
2020						$26.29	$20.13
2021						$29.65	$23.23
2022						$31.44	$24.81
2023						$32.98	$26.60
2024						$35.31	$28.93
2025						$38.12	$31.73
2026						$39.30	$32.99
2027						$40.50	$34.11
2028						$42.25	$36.19
2029						$46.07	$39.72
2030	$142.88	$44.06	64.80%	92.59	$44.06	$87.27	$43.21
2031	$145.92	$44.24	64.80%	94.56	$45.00	$88.37	$43.37
2032	$148.97	$46.98	64.80%	96.54	$45.94	$92.03	$46.09
2033	$152.06	$49.15	64.80%	98.54	$46.90	$95.13	$48.24
2034	$155.20	$48.69	64.80%	100.57	$47.86	$95.63	$47.76
2035	$158.39	$49.91	64.80%	102.64	$48.85	$97.80	$48.96
2036	$161.60	$49.84	64.80%	104.72	$49.84	$98.71	$48.87

(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		Renewable Base Load 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 84%	(d) *1000 / (100.0%x 8760 x 56%)	= (a) + (e)	= (b)
2018						$23.67	$16.52
2019						$24.61	$17.98
2020						$26.94	$20.78
2021	$31.36	$24.61	$116.58	$98.16	$19.99	$51.99	$25.25
2022	$32.02	$25.40	$119.51	$100.63	$20.50	$53.18	$26.06
2023	$32.63	$26.22	$122.37	$103.04	$20.99	$54.30	$26.90
2024	$33.08	$27.18	$125.24	$105.45	$21.48	$55.26	$27.88
2025	$33.62	$28.13	$128.14	$107.89	$21.98	$56.32	$28.85
2026	$34.28	$28.89	$131.05	$110.34	$22.48	$57.50	$29.63
2027	$35.02	$29.57	$133.94	$112.78	$22.97	$58.75	$30.33
2028	$35.68	$30.37	$136.84	$115.22	$23.47	$59.93	$31.15
2029	$36.30	$31.23	$139.84	$117.75	$23.98	$61.08	$32.03
2030	$37.04	$31.95	$142.88	$120.30	$24.51	$62.37	$32.77
2031	$37.75	$32.74	$145.92	$122.86	$25.03	$63.62	$33.58
2032	$38.50	$33.47	$148.97	$125.43	$25.55	$64.91	$34.33
2033	$39.22	$34.27	$152.06	$128.03	$26.08	$66.18	$35.15
2034	$40.04	$34.98	$155.20	$130.68	$26.62	$67.56	$35.88
2035	$40.79	$35.78	$158.39	$133.36	$27.17	$68.88	$36.70
2036	$41.56	$36.57	$161.60	$136.07	$27.72	$70.22	$37.51

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) 2018-2020 On-Peak Blended Market Prices for QF resource
- (g) 2018-2020 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

	Renewable Wind Avoided Resource		Wind QF Resource			Wind QF Resource	
Year	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)
2018						$23.08	$15.93
2019						$24.01	$17.38
2020						$26.32	$20.16
2021	$31.36	$24.61	$116.58	($4.69)	($2.43)	$28.93	$24.61
2022	$32.02	$25.40	$119.51	($4.81)	($2.49)	$29.53	$25.40
2023	$32.63	$26.22	$122.37	($4.92)	($2.55)	$30.08	$26.22
2024	$33.08	$27.18	$125.24	($5.04)	($2.61)	$30.47	$27.18
2025	$33.62	$28.13	$128.14	($5.16)	($2.67)	$30.95	$28.13
2026	$34.28	$28.89	$131.05	($5.27)	($2.73)	$31.55	$28.89
2027	$35.02	$29.57	$133.94	($5.39)	($2.79)	$32.23	$29.57
2028	$35.68	$30.37	$136.84	($5.51)	($2.85)	$32.83	$30.37
2029	$36.30	$31.23	$139.84	($5.63)	($2.92)	$33.38	$31.23
2030	$37.04	$31.95	$142.88	($5.75)	($2.98)	$34.06	$31.95
2031	$37.75	$32.74	$145.92	($5.87)	($3.04)	$34.71	$32.74
2032	$38.50	$33.47	$148.97	($5.99)	($3.11)	$35.39	$33.47
2033	$39.22	$34.27	$152.06	($6.12)	($3.17)	$36.05	$34.27
2034	$40.04	$34.98	$155.20	($6.24)	($3.24)	$36.80	$34.98
2035	$40.79	$35.78	$158.39	($6.37)	($3.30)	$37.49	$35.78
2036	$41.56	$36.57	$161.60	($6.50)	($3.37)	$38.19	$36.57

(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) 2018-2020 On-Peak Blended Market Prices for QF resource
- (g) 2018-2020 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 On-Peak ($/MWh) (a)	Renewable Wind Avoided Resource Off-Peak ($/MWh) (b)	Fixed Solar QF Resource Avoided Firm Capacity Costs $/kW-yr (c)	QF Capacity Adder ($/kW-yr) (d) (c) x 38.1%	Capacity Adder Allocated to On-Peak Hours ($/MWh) (e) (d) *1000 / (37.3%x 8760 x 56%)	Fixed Solar QF On-Peak $/MWh (f) = (a) + (e)	Fixed Solar QF Off-Peak $/MWh (g) = (b)
2018						$23.05	$15.90
2019						$23.98	$17.35
2020						$26.29	$20.13
2021	$31.36	$24.61	$116.58	$44.37	$24.21	$55.54	$24.58
2022	$32.02	$25.40	$119.51	$45.49	$24.82	$56.81	$25.37
2023	$32.63	$26.22	$122.37	$46.58	$25.42	$58.02	$26.19
2024	$33.08	$27.18	$125.24	$47.67	$26.01	$59.06	$27.15
2025	$33.62	$28.13	$128.14	$48.77	$26.62	$60.21	$28.10
2026	$34.28	$28.89	$131.05	$49.88	$27.22	$61.47	$28.86
2027	$35.02	$29.57	$133.94	$50.98	$27.82	$62.81	$29.54
2028	$35.68	$30.37	$136.84	$52.08	$28.42	$64.07	$30.34
2029	$36.30	$31.23	$139.84	$53.23	$29.05	$65.32	$31.20
2030	$37.04	$31.95	$142.88	$54.38	$29.68	$66.69	$31.92
2031	$37.75	$32.74	$145.92	$55.54	$30.31	$68.03	$32.71
2032	$38.50	$33.47	$148.97	$56.70	$30.94	$69.41	$33.44
2033	$39.22	$34.27	$152.06	$57.88	$31.58	$70.77	$34.24
2034	$40.04	$34.98	$155.20	$59.07	$32.24	$72.25	$34.95
2035	$40.79	$35.78	$158.39	$60.29	$32.90	$73.66	$35.75
2036	$41.56	$36.57	$161.60	$61.51	$33.57	$75.10	$36.54

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) 2018-2020 On-Peak Blended Market Prices for QF resource
- (g) 2018-2020 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		Tracking Solar QF Resource			Tracking 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 49.0%	(d) *1000 / (42.8%x 8760 x 56%)	= (a) + (e)	= (b)
2018						$23.05	$15.90
2019						$23.98	$17.35
2020						$26.29	$20.13
2021	$31.36	$24.61	$116.58	$57.13	$27.19	$58.52	$24.58
2022	$32.02	$25.40	$119.51	$58.56	$27.87	$59.86	$25.37
2023	$32.63	$26.22	$122.37	$59.97	$28.54	$61.14	$26.19
2024	$33.08	$27.18	$125.24	$61.37	$29.21	$62.26	$27.15
2025	$33.62	$28.13	$128.14	$62.79	$29.88	$63.47	$28.10
2026	$34.28	$28.89	$131.05	$64.22	$30.56	$64.81	$28.86
2027	$35.02	$29.57	$133.94	$65.63	$31.24	$66.23	$29.54
2028	$35.68	$30.37	$136.84	$67.06	$31.91	$67.56	$30.34
2029	$36.30	$31.23	$139.84	$68.53	$32.61	$68.88	$31.20
2030	$37.04	$31.95	$142.88	$70.02	$33.32	$70.33	$31.92
2031	$37.75	$32.74	$145.92	$71.51	$34.03	$71.75	$32.71
2032	$38.50	$33.47	$148.97	$73.00	$34.74	$73.21	$33.44
2033	$39.22	$34.27	$152.06	$74.51	$35.46	$74.65	$34.24
2034	$40.04	$34.98	$155.20	$76.05	$36.19	$76.20	$34.95
2035	$40.79	$35.78	$158.39	$77.62	$36.94	$77.70	$35.75
2036	$41.56	$36.57	$161.60	$79.19	$37.69	$79.22	$36.54

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) 2018-2020 On-Peak Blended Market Prices for QF resource
- (g) 2018-2020 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
1/1/2018	0.0%	100.0%	0.0%	100.0%	0.0%	94.4%	5.6%	100.0%
2/1/2018	0.0%	99.4%	0.6%	100.0%	20.4%	76.2%	3.5%	100.0%
3/1/2018	0.0%	92.6%	7.4%	100.0%	0.0%	99.1%	0.9%	100.0%
4/1/2018	53.1%	27.2%	19.6%	100.0%	43.6%	52.7%	3.7%	100.0%
5/1/2018	75.2%	11.1%	13.8%	100.0%	61.4%	38.6%	0.0%	100.0%
6/1/2018	91.0%	2.2%	6.8%	100.0%	94.1%	5.9%	0.0%	100.0%
7/1/2018	41.6%	50.0%	8.3%	100.0%	88.9%	5.9%	5.1%	100.0%
8/1/2018	36.0%	58.7%	5.3%	100.0%	0.6%	94.2%	5.2%	100.0%
9/1/2018	12.6%	74.3%	13.1%	100.0%	0.0%	8.9%	91.1%	100.0%
10/1/2018	0.0%	80.5%	19.5%	100.0%	0.0%	92.1%	7.9%	100.0%
11/1/2018	1.1%	94.1%	4.8%	100.0%	0.0%	96.8%	3.2%	100.0%
12/1/2018	2.5%	90.5%	7.0%	100.0%	1.3%	47.7%	51.0%	100.0%
1/1/2019	0.0%	93.6%	6.4%	100.0%	0.0%	77.7%	22.3%	100.0%
2/1/2019	1.8%	94.8%	3.4%	100.0%	0.0%	87.6%	12.4%	100.0%
3/1/2019	3.4%	85.5%	11.2%	100.0%	11.1%	84.3%	4.6%	100.0%
4/1/2019	11.1%	70.7%	18.2%	100.0%	29.8%	69.5%	0.7%	100.0%
5/1/2019	23.3%	66.4%	10.2%	100.0%	58.9%	40.8%	0.3%	100.0%
6/1/2019	6.2%	93.8%	0.0%	100.0%	28.0%	72.0%	0.0%	100.0%
7/1/2019	32.4%	61.5%	6.1%	100.0%	17.5%	81.2%	1.3%	100.0%
8/1/2019	30.5%	60.7%	8.8%	100.0%	1.2%	98.6%	0.2%	100.0%
9/1/2019	15.9%	80.3%	3.8%	100.0%	0.0%	85.5%	14.5%	100.0%
10/1/2019	0.4%	77.6%	22.0%	100.0%	0.0%	97.8%	2.2%	100.0%
11/1/2019	1.5%	87.3%	11.1%	100.0%	0.0%	32.7%	67.3%	100.0%
12/1/2019	4.6%	89.8%	5.5%	100.0%	0.0%	43.0%	57.0%	100.0%
1/1/2020	0.0%	37.1%	62.9%	100.0%	0.0%	0.0%	100.0%	100.0%
2/1/2020	8.4%	56.6%	35.0%	100.0%	8.9%	74.8%	16.4%	100.0%
3/1/2020	0.3%	83.5%	16.2%	100.0%	1.4%	89.5%	9.1%	100.0%
4/1/2020	0.0%	81.6%	18.4%	100.0%	1.4%	92.3%	6.3%	100.0%
5/1/2020	1.2%	97.2%	1.6%	100.0%	26.1%	72.4%	1.5%	100.0%
6/1/2020	6.8%	91.4%	1.8%	100.0%	56.6%	43.4%	0.0%	100.0%
7/1/2020	46.3%	51.2%	2.5%	100.0%	14.7%	84.8%	0.5%	100.0%
8/1/2020	37.4%	56.0%	6.6%	100.0%	1.8%	97.2%	0.9%	100.0%
9/1/2020	12.6%	75.0%	12.3%	100.0%	0.0%	87.6%	12.4%	100.0%
10/1/2020	0.7%	90.0%	9.3%	100.0%	0.0%	98.4%	1.6%	100.0%
11/1/2020	0.0%	86.3%	13.7%	100.0%	0.0%	45.4%	54.6%	100.0%
12/1/2020	0.3%	57.5%	42.1%	100.0%	0.0%	32.1%	67.9%	100.0%
1/1/2021	0.0%	65.1%	34.9%	100.0%	0.0%	0.0%	100.0%	100.0%
2/1/2021	0.0%	83.2%	16.8%	100.0%	0.0%	31.2%	68.8%	100.0%
3/1/2021	0.0%	84.2%	15.8%	100.0%	0.0%	88.3%	11.7%	100.0%
4/1/2021	3.5%	78.4%	18.1%	100.0%	1.1%	88.5%	10.4%	100.0%
5/1/2021	1.3%	96.4%	2.3%	100.0%	12.1%	85.3%	2.6%	100.0%
6/1/2021	1.8%	97.0%	1.1%	100.0%	31.6%	68.4%	0.0%	100.0%
7/1/2021	23.8%	75.3%	1.0%	100.0%	5.9%	91.9%	2.2%	100.0%
8/1/2021	23.9%	72.4%	3.7%	100.0%	1.8%	92.3%	5.9%	100.0%
9/1/2021	0.0%	87.7%	12.3%	100.0%	0.0%	75.4%	24.6%	100.0%
10/1/2021	0.0%	92.4%	7.6%	100.0%	0.0%	96.5%	3.5%	100.0%
11/1/2021	0.0%	87.1%	12.9%	100.0%	0.0%	62.4%	37.6%	100.0%
12/1/2021	0.4%	57.1%	42.4%	100.0%	0.0%	30.5%	69.5%	100.0%

Exhibit 9
Market Price - Blending Matrix (1)

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2022	0.0%	42.6%	57.4%	100.0%	0.0%	16.5%	83.5%	100.0%
2/1/2022	0.0%	81.5%	18.5%	100.0%	0.0%	58.4%	41.6%	100.0%
3/1/2022	0.0%	86.3%	13.7%	100.0%	0.0%	88.8%	11.2%	100.0%
4/1/2022	7.0%	63.3%	29.7%	100.0%	0.4%	80.7%	18.9%	100.0%
5/1/2022	0.0%	90.1%	9.9%	100.0%	1.4%	92.1%	6.6%	100.0%
6/1/2022	28.0%	72.0%	0.0%	100.0%	52.7%	47.3%	0.0%	100.0%
7/1/2022	21.6%	74.8%	3.5%	100.0%	13.0%	87.0%	0.0%	100.0%
8/1/2022	22.1%	72.8%	5.1%	100.0%	2.3%	97.3%	0.4%	100.0%
9/1/2022	13.6%	86.2%	0.2%	100.0%	2.8%	25.9%	71.3%	100.0%
10/1/2022	0.5%	76.0%	23.4%	100.0%	0.0%	86.2%	13.8%	100.0%
11/1/2022	0.0%	50.8%	49.2%	100.0%	0.0%	0.0%	100.0%	100.0%
12/1/2022	1.3%	64.3%	34.4%	100.0%	0.0%	63.3%	36.7%	100.0%
1/1/2023	0.0%	63.9%	36.1%	100.0%	0.0%	26.1%	73.9%	100.0%
2/1/2023	10.6%	62.0%	27.4%	100.0%	0.0%	75.1%	24.9%	100.0%
3/1/2023	0.5%	78.4%	21.1%	100.0%	0.0%	100.0%	0.0%	100.0%
4/1/2023	9.7%	67.2%	23.0%	100.0%	1.0%	92.1%	6.9%	100.0%
5/1/2023	1.7%	98.3%	0.0%	100.0%	19.8%	74.4%	5.8%	100.0%
6/1/2023	3.7%	94.3%	2.1%	100.0%	18.3%	80.9%	0.8%	100.0%
7/1/2023	19.9%	76.6%	3.5%	100.0%	12.3%	86.4%	1.3%	100.0%
8/1/2023	19.6%	75.3%	5.1%	100.0%	0.3%	95.0%	4.7%	100.0%
9/1/2023	10.7%	89.1%	0.2%	100.0%	1.4%	27.5%	71.1%	100.0%
10/1/2023	0.5%	68.6%	31.0%	100.0%	0.0%	67.2%	32.8%	100.0%
11/1/2023	0.0%	51.2%	48.8%	100.0%	0.0%	0.0%	100.0%	100.0%
12/1/2023	0.5%	68.3%	31.3%	100.0%	0.0%	63.8%	36.2%	100.0%
1/1/2024	0.0%	89.0%	11.0%	100.0%	0.0%	85.8%	14.2%	100.0%
2/1/2024	16.1%	65.2%	18.7%	100.0%	8.3%	71.5%	20.2%	100.0%
3/1/2024	0.0%	81.5%	18.5%	100.0%	0.0%	70.2%	29.8%	100.0%
4/1/2024	25.4%	59.6%	15.0%	100.0%	9.2%	90.3%	0.5%	100.0%
5/1/2024	2.7%	97.3%	0.0%	100.0%	28.9%	62.6%	8.5%	100.0%
6/1/2024	12.5%	84.7%	2.7%	100.0%	37.0%	63.0%	0.0%	100.0%
7/1/2024	27.2%	69.6%	3.2%	100.0%	6.0%	93.5%	0.5%	100.0%
8/1/2024	23.6%	72.7%	3.7%	100.0%	3.3%	93.9%	2.8%	100.0%
9/1/2024	19.9%	68.2%	11.9%	100.0%	2.4%	13.2%	84.4%	100.0%
10/1/2024	0.0%	69.1%	30.9%	100.0%	0.0%	97.0%	3.0%	100.0%
11/1/2024	8.2%	75.1%	16.7%	100.0%	0.0%	100.0%	0.0%	100.0%
12/1/2024	0.1%	69.9%	30.0%	100.0%	0.0%	96.3%	3.7%	100.0%
1/1/2025	0.0%	84.0%	16.0%	100.0%	0.0%	80.2%	19.8%	100.0%
2/1/2025	28.8%	45.6%	25.6%	100.0%	0.0%	40.9%	59.1%	100.0%
3/1/2025	16.5%	62.6%	20.9%	100.0%	0.0%	98.4%	1.6%	100.0%
4/1/2025	25.8%	59.7%	14.4%	100.0%	8.8%	84.8%	6.5%	100.0%
5/1/2025	6.6%	93.2%	0.1%	100.0%	28.1%	65.8%	6.1%	100.0%
6/1/2025	18.2%	76.0%	5.8%	100.0%	31.8%	68.2%	0.0%	100.0%
7/1/2025	25.6%	72.0%	2.4%	100.0%	3.3%	95.5%	1.2%	100.0%
8/1/2025	21.5%	73.7%	4.9%	100.0%	3.9%	81.9%	14.3%	100.0%
9/1/2025	2.9%	42.2%	54.9%	100.0%	6.3%	10.0%	83.7%	100.0%
10/1/2025	8.7%	79.7%	11.6%	100.0%	9.7%	88.8%	1.5%	100.0%
11/1/2025	33.6%	63.3%	3.1%	100.0%	15.4%	69.4%	15.2%	100.0%
12/1/2025	20.7%	71.3%	8.0%	100.0%	4.6%	92.7%	2.7%	100.0%

Exhibit 9
Market Price - Blending Matrix (1)

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2026	32.0%	64.4%	3.6%	100.0%	0.0%	96.5%	3.5%	100.0%
2/1/2026	38.0%	49.9%	12.1%	100.0%	27.5%	40.0%	32.4%	100.0%
3/1/2026	34.4%	63.6%	2.0%	100.0%	2.9%	95.2%	1.9%	100.0%
4/1/2026	17.4%	62.8%	19.8%	100.0%	7.2%	74.8%	18.0%	100.0%
5/1/2026	7.6%	92.4%	0.0%	100.0%	23.0%	74.7%	2.3%	100.0%
6/1/2026	15.8%	81.5%	2.7%	100.0%	15.4%	84.6%	0.0%	100.0%
7/1/2026	24.9%	74.1%	1.1%	100.0%	7.3%	91.5%	1.2%	100.0%
8/1/2026	20.5%	75.0%	4.4%	100.0%	11.9%	76.7%	11.4%	100.0%
9/1/2026	4.9%	32.6%	62.4%	100.0%	7.6%	5.4%	87.0%	100.0%
10/1/2026	18.1%	68.1%	13.9%	100.0%	10.2%	86.5%	3.3%	100.0%
11/1/2026	50.4%	41.9%	7.7%	100.0%	39.9%	43.8%	16.3%	100.0%
12/1/2026	30.1%	59.8%	10.1%	100.0%	5.2%	87.7%	7.1%	100.0%
1/1/2027	29.0%	67.6%	3.5%	100.0%	6.7%	87.3%	6.0%	100.0%
2/1/2027	36.7%	58.3%	5.0%	100.0%	38.4%	30.0%	31.7%	100.0%
3/1/2027	39.8%	57.1%	3.1%	100.0%	4.5%	92.7%	2.8%	100.0%
4/1/2027	48.5%	48.8%	2.7%	100.0%	14.1%	79.2%	6.7%	100.0%
5/1/2027	3.3%	96.7%	0.0%	100.0%	18.4%	76.0%	5.6%	100.0%
6/1/2027	15.1%	83.1%	1.8%	100.0%	14.6%	85.4%	0.0%	100.0%
7/1/2027	18.1%	79.1%	2.8%	100.0%	9.3%	88.8%	1.8%	100.0%
8/1/2027	20.4%	75.8%	3.8%	100.0%	9.8%	79.0%	11.2%	100.0%
9/1/2027	9.2%	45.5%	45.3%	100.0%	3.9%	5.7%	90.4%	100.0%
10/1/2027	36.6%	45.1%	18.2%	100.0%	31.2%	51.6%	17.3%	100.0%
11/1/2027	52.7%	41.3%	5.9%	100.0%	41.1%	28.8%	30.1%	100.0%
12/1/2027	30.5%	59.2%	10.2%	100.0%	4.6%	94.3%	1.1%	100.0%
1/1/2028	27.3%	62.6%	10.1%	100.0%	2.0%	94.3%	3.6%	100.0%
2/1/2028	37.2%	36.1%	26.7%	100.0%	36.6%	29.1%	34.2%	100.0%
3/1/2028	42.7%	50.9%	6.4%	100.0%	17.4%	73.9%	8.7%	100.0%
4/1/2028	53.3%	42.1%	4.5%	100.0%	27.7%	62.4%	9.8%	100.0%
5/1/2028	10.9%	89.1%	0.0%	100.0%	29.4%	68.0%	2.6%	100.0%
6/1/2028	25.0%	71.7%	3.3%	100.0%	44.7%	55.1%	0.2%	100.0%
7/1/2028	4.2%	92.6%	3.3%	100.0%	20.2%	74.9%	4.9%	100.0%
8/1/2028	34.0%	55.7%	10.3%	100.0%	14.3%	68.8%	16.8%	100.0%
9/1/2028	15.0%	30.2%	54.8%	100.0%	7.8%	4.7%	87.5%	100.0%
10/1/2028	30.1%	36.9%	33.0%	100.0%	11.2%	76.4%	12.4%	100.0%
11/1/2028	40.1%	41.7%	18.2%	100.0%	29.4%	19.3%	51.3%	100.0%
12/1/2028	27.5%	50.8%	21.7%	100.0%	3.9%	88.1%	7.9%	100.0%
1/1/2029	36.4%	59.6%	4.0%	100.0%	7.8%	80.7%	11.4%	100.0%
2/1/2029	43.5%	43.7%	12.8%	100.0%	26.4%	31.7%	42.0%	100.0%
3/1/2029	44.7%	47.5%	7.8%	100.0%	19.5%	68.6%	11.9%	100.0%
4/1/2029	23.5%	59.4%	17.1%	100.0%	11.5%	69.7%	18.8%	100.0%
5/1/2029	21.3%	78.4%	0.3%	100.0%	22.9%	64.8%	12.3%	100.0%
6/1/2029	38.0%	61.5%	0.4%	100.0%	56.2%	43.8%	0.0%	100.0%
7/1/2029	9.1%	84.0%	6.9%	100.0%	19.7%	75.7%	4.6%	100.0%
8/1/2029	38.6%	48.8%	12.5%	100.0%	14.1%	73.6%	12.2%	100.0%
9/1/2029	19.4%	34.8%	45.8%	100.0%	12.9%	5.2%	81.8%	100.0%
10/1/2029	31.0%	36.8%	32.2%	100.0%	11.8%	78.1%	10.1%	100.0%
11/1/2029	30.9%	46.7%	22.5%	100.0%	38.2%	47.2%	14.5%	100.0%
12/1/2029	22.8%	44.8%	32.5%	100.0%	14.3%	74.8%	10.9%	100.0%

(1) Blending weights are calculated using system balancing purchases and sales from GRID run using Mar 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)												
2018	22.51	20.61	20.82	17.22	16.16	17.40	29.53	36.53	29.47	23.05	21.75	28.97
2019	28.12	24.64	20.05	16.14	17.46	19.98	29.74	33.13	28.65	22.94	24.66	29.75
2020	30.04	28.04	23.00	21.17	20.09	20.63	30.50	34.04	29.28	25.58	27.81	33.09
2021	35.67	31.41	26.12	24.75	22.94	23.32	32.85	36.89	32.07	28.98	31.42	37.38
2022	36.55	33.17	27.55	28.47	26.78	22.24	33.82	38.46	36.10	33.13	33.67	35.64
2023	35.03	34.93	32.15	30.80	25.27	24.95	35.67	40.36	37.85	34.77	35.30	37.17
2024	35.79	35.96	32.83	29.21	25.35	27.89	41.41	45.98	43.97	36.46	38.18	39.41
2025	38.19	38.99	34.11	32.11	25.59	31.05	46.56	51.57	47.50	38.14	40.88	41.73
2026	40.49	41.40	33.79	35.21	25.80	31.46	48.30	51.90	47.62	38.90	42.90	43.06
2027	41.66	42.43	34.83	32.75	26.59	32.35	49.29	53.40	50.34	42.79	44.42	44.57
2028	43.40	43.37	36.90	34.23	28.93	34.97	50.79	57.11	50.12	43.14	46.64	47.15
2029	46.54	46.93	40.38	40.72	32.53	36.35	55.74	62.55	55.53	46.64	47.95	50.90
2030	50.37	49.62	43.05	40.83	35.23	39.22	58.90	65.54	61.88	52.76	51.30	54.21
2031	53.85	52.97	42.81	41.16	35.46	39.67	58.00	64.41	60.31	50.15	50.62	54.64
2032	53.02	52.34	46.64	47.88	38.44	44.06	61.63	68.96	64.41	54.40	56.58	58.23
2033	56.96	56.75	48.21	45.58	40.44	46.47	63.52	71.18	67.11	58.93	58.36	59.39
2034	58.71	58.83	47.71	45.76	40.22	46.43	63.87	71.00	65.40	56.06	58.35	59.56
2035	58.54	59.67	50.50	52.58	42.92	46.38	66.75	75.01	69.88	57.95	58.33	60.35
2036	59.27	59.65	48.82	47.73	40.78	47.31	68.40	74.85	72.01	62.01	59.53	62.38
Off-Peak (LLH Market Purchase)												
2018	20.38	13.36	18.18	11.81	4.63	4.85	16.62	23.50	23.08	19.51	18.74	23.62
2019	23.25	21.44	16.90	9.54	9.45	12.41	17.25	20.67	20.93	18.97	21.52	23.48
2020	26.77	24.06	19.93	15.09	13.93	13.94	18.12	21.83	22.48	21.64	24.13	27.42
2021	29.37	27.63	22.90	18.56	16.16	15.77	21.11	25.55	26.07	24.93	27.65	31.06
2022	31.32	29.14	24.29	21.84	18.75	14.31	21.73	26.23	31.79	27.34	28.59	30.68
2023	31.61	29.91	28.13	23.13	19.47	18.58	23.64	28.12	33.45	29.31	30.14	32.23
2024	31.75	31.66	30.09	20.47	23.02	23.12	29.70	34.60	36.76	29.47	32.65	32.60
2025	32.94	34.64	29.16	25.94	25.46	26.04	36.15	41.41	39.89	30.48	34.31	33.34
2026	33.26	36.64	28.93	31.37	25.30	25.38	38.21	42.09	40.17	31.77	36.20	35.76
2027	35.09	37.39	30.08	28.58	26.28	26.35	39.44	43.18	42.37	35.91	37.13	37.03
2028	36.61	38.68	32.60	30.91	27.80	29.80	42.13	45.60	43.54	36.13	39.76	40.37
2029	39.25	42.12	36.20	36.92	31.02	32.53	45.59	50.44	47.66	39.12	41.75	44.01
2030	42.85	45.21	38.42	36.61	33.23	35.90	48.65	53.20	52.95	45.50	45.69	46.45
2031	45.89	48.39	38.92	36.62	34.25	36.11	47.79	53.20	51.92	42.22	45.40	46.04
2032	45.27	47.58	41.20	43.20	37.63	39.68	51.38	56.34	56.04	46.47	49.93	50.35
2033	49.77	52.10	43.99	42.03	38.78	41.21	53.97	58.18	58.51	50.78	52.18	51.75
2034	51.41	53.81	42.87	41.61	37.25	40.36	54.32	58.12	57.55	47.89	52.44	52.22
2035	50.49	54.66	45.61	47.59	40.45	41.87	56.24	61.59	60.88	49.13	51.21	52.90
2036	51.03	55.20	43.81	43.74	38.23	41.33	57.30	62.82	62.59	52.93	53.72	54.19

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
Combined												
2018	21.59	17.49	19.68	14.89	11.20	12.00	23.98	30.93	26.72	21.53	20.46	26.67
2019	26.02	23.26	18.70	13.30	14.01	16.73	24.37	27.77	25.33	21.23	23.31	27.05
2020	28.63	26.33	21.68	18.55	17.44	17.75	25.18	28.79	26.36	23.89	26.23	30.65
2021	32.96	29.79	24.74	22.09	20.02	20.07	27.80	32.02	29.49	27.24	29.80	34.66
2022	34.30	31.44	26.14	25.62	23.33	18.83	28.62	33.20	34.25	30.64	31.49	33.51
2023	33.56	32.77	30.42	27.50	22.78	22.21	30.49	35.10	35.96	32.42	33.08	35.05
2024	34.05	34.11	31.65	25.45	24.35	25.84	36.38	41.09	40.87	33.46	35.80	36.48
2025	35.94	37.12	31.98	29.46	25.54	28.89	42.08	47.20	44.23	34.85	38.06	38.13
2026	37.38	39.36	31.70	33.56	25.58	28.85	43.96	47.68	44.41	35.84	40.02	39.92
2027	38.84	40.26	32.79	30.96	26.46	29.77	45.05	49.01	46.91	39.83	41.28	41.33
2028	40.48	41.35	35.05	32.80	28.44	32.75	47.07	52.16	47.29	40.12	43.68	44.23
2029	43.41	44.87	38.59	39.08	31.88	34.71	51.37	57.34	52.15	43.41	45.28	47.94
2030	47.13	47.72	41.06	39.01	34.37	37.79	54.49	60.23	58.04	49.64	48.89	50.87
2031	50.43	51.00	41.14	39.21	34.94	38.14	53.61	59.59	56.71	46.74	48.38	50.94
2032	49.69	50.30	44.30	45.87	38.09	42.18	57.22	63.53	60.81	50.99	53.72	54.84
2033	53.87	54.75	46.40	44.05	39.73	44.21	59.41	65.59	63.41	55.43	55.70	56.11
2034	55.57	56.67	45.63	43.98	38.94	43.82	59.76	65.46	62.02	52.55	55.80	56.41
2035	55.08	57.51	48.40	50.43	41.85	44.44	62.23	69.24	66.01	54.16	55.27	57.15
2036	55.72	57.73	46.67	46.01	39.69	44.74	63.63	69.67	67.96	58.10	57.03	58.86

Annual Average

	On-Peak	Off-Peak	Combined
2018	$23.67	$16.52	$20.60
2019	$24.61	$17.98	$21.76
2020	$26.94	$20.78	$24.29
2021	$30.32	$23.90	$27.56
2022	$32.13	$25.50	$29.28
2023	$33.69	$27.31	$30.94
2024	$36.04	$29.66	$33.29
2025	$38.87	$32.48	$36.12
2026	$40.07	$33.76	$37.36
2027	$41.29	$34.90	$38.54
2028	$43.06	$37.00	$40.45
2029	$46.90	$40.55	$44.17
2030	$50.24	$43.72	$47.44
2031	$50.34	$43.90	$47.57
2032	$53.88	$47.09	$50.96
2033	$56.08	$49.44	$53.22
2034	$55.99	$49.15	$53.05
2035	$58.24	$51.05	$55.15
2036	$58.56	$51.41	$55.48

Source Offical Market Price Forecast dated March 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 March 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 ($/kW-yr)	Capitalized Energy Costs 70.3% CF ($/MWh)
	(a)	(b)	(c) ((a) - (b))	(d) (c)/(8.760 x 70.3%)
2030	$212.87	$142.88	$69.99	$11.37
2031	$217.41	$145.92	$71.49	$11.61
2032	$221.96	$148.97	$72.99	$11.85
2033	$226.57	$152.06	$74.51	$12.10
2034	$231.24	$155.20	$76.04	$12.35
2035	$235.98	$158.39	$77.59	$12.60
2036	$240.76	$161.60	$79.16	$12.85
2037	$245.59	$164.88	$80.71	$13.11

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	Combined Cycle Energy Cost	Capitalized Energy Costs 70.3% CF	Total Standard Avoided Energy Cost
	($/MMBtu)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)
		(a) x 6.410		(b) + (c)
2030	$5.10	$32.69	$11.37	$44.06
2031	$5.09	$32.63	$11.61	$44.24
2032	$5.48	$35.13	$11.85	$46.98
2033	$5.78	$37.05	$12.10	$49.15
2034	$5.67	$36.34	$12.35	$48.69
2035	$5.82	$37.31	$12.60	$49.91
2036	$5.77	$36.99	$12.85	$49.84
2037	$6.15	$39.42	$13.11	$52.53

Columns

(a) Table 10

(b) 6.410 MWh/MMBtu Heat Rate - Table 9

(c) Table 3 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 ($/kW-yr)	Capitalized Energy Costs 70.3% CF ($/MWh)
	(a)	(b)	(c)	(d)
			((a) - (b))	(c)/(8.760 x 70.3%)
2018	$161.01	$108.15	$52.86	$8.58
2019	$164.72	$110.64	$54.08	$8.78
2020	$169.11	$113.57	$55.54	$9.02
2021	$173.57	$116.58	$56.99	$9.25
2022	$177.96	$119.51	$58.45	$9.49
2023	$182.24	$122.37	$59.87	$9.72
2024	$186.53	$125.24	$61.29	$9.95
2025	$190.86	$128.14	$62.72	$10.18
2026	$195.22	$131.05	$64.17	$10.42
2027	$199.54	$133.94	$65.60	$10.65
2028	$203.89	$136.84	$67.05	$10.89
2029	$208.36	$139.84	$68.52	$11.13
2030	$212.87	$142.88	$69.99	$11.37
2031	$217.41	$145.92	$71.49	$11.61
2032	$221.96	$148.97	$72.99	$11.85
2033	$226.57	$152.06	$74.51	$12.10
2034	$231.24	$155.20	$76.04	$12.35
2035	$235.98	$158.39	$77.59	$12.60
2036	$240.76	$161.60	$79.16	$12.85

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	$108.15
2019	$110.64
2020	$113.57
2021	$116.58
2022	$119.51
2023	$122.37
2024	$125.24
2025	$128.14
2026	$131.05
2027	$133.94
2028	$136.84
2029	$139.84
2030	$142.88
2031	$145.92
2032	$148.97
2033	$152.06
2034	$155.20
2035	$158.39
2036	$161.60

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

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	$142.88	$44.06	$65.80	$63.25	$62.18
2031	$145.92	$44.24	$66.45	$63.83	$62.74
2032	$148.97	$46.98	$69.65	$66.99	$65.87
2033	$152.06	$49.15	$72.29	$69.57	$68.44
2034	$155.20	$48.69	$72.31	$69.54	$68.38
2035	$158.39	$49.91	$74.01	$71.18	$70.00
2036	$161.60	$49.84	$74.44	$71.54	$70.34
2037	$164.88	$52.53	$77.62	$74.67	$73.44

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	$142.88	$29.10	$44.06	$73.16	$44.06
2031	$145.92	$29.72	$44.24	$73.96	$44.24
2032	$148.97	$30.34	$46.98	$77.32	$46.98
2033	$152.06	$30.97	$49.15	$80.12	$49.15
2034	$155.20	$31.61	$48.69	$80.31	$48.69
2035	$158.39	$32.26	$49.91	$82.17	$49.91
2036	$161.60	$32.92	$49.84	$82.76	$49.84
2037	$164.88	$33.59	$52.53	$86.11	$52.53

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

Year	Proposed Standard Base Load QF	Current Standard Base Load QF	Difference Standard Base Load QF	Proposed Standard Wind QF (2)	Current Standard Wind QF (2)	Difference Standard Wind QF (2)	Proposed Standard Fixed Solar QF	Current Standard Fixed Solar QF	Difference Standard Fixed Solar QF	Proposed Standard Tracking Solar QF	Current Standard Tracking Solar QF	Difference Standard Tracking Solar QF
2018	$20.53	$22.27	($1.74)	$20.08	$18.89	$1.19	$21.91	$23.82	($1.91)	$21.86	$23.82	($1.96)
2019	$21.70	$22.81	($1.11)	$21.23	$19.35	$1.87	$22.92	$24.38	($1.46)	$22.88	$24.39	($1.51)
2020	$24.23	$24.56	($0.33)	$23.73	$21.03	$2.71	$25.31	$26.30	($0.99)	$25.27	$26.30	($1.04)
2021	$27.50	$25.30	$2.19	$26.98	$21.65	$5.33	$28.63	$27.56	$1.07	$28.59	$27.56	$1.02
2022	$29.22	$28.00	$1.21	$28.69	$24.30	$4.38	$30.38	$29.81	$0.58	$30.34	$29.81	$0.53
2023	$30.89	$30.91	($0.02)	$30.33	$27.14	$3.20	$31.96	$32.63	($0.67)	$31.92	$32.63	($0.71)
2024	$33.24	$31.94	$1.29	$32.66	$27.97	$4.69	$34.29	$35.24	($0.94)	$34.25	$35.24	($0.99)
2025	$36.06	$36.82	($0.76)	$35.47	$32.88	$2.59	$37.10	$38.57	($1.47)	$37.06	$38.57	($1.51)
2026	$37.30	$37.31	($0.02)	$36.68	$33.28	$3.40	$38.30	$39.00	($0.71)	$38.25	$39.00	($0.75)
2027	$38.48	$38.47	$0.01	$37.85	$34.35	$3.49	$39.48	$40.10	($0.61)	$39.44	$40.10	($0.66)
2028	$40.40	$44.77	($4.37)	$39.73	$36.30	$3.43	$41.28	$49.56	($8.27)	$41.24	$49.19	($7.94)
2029	$44.11	$47.52	($3.41)	$43.43	$38.85	$4.58	$45.06	$52.43	($7.37)	$45.02	$52.04	($7.03)
2030	$60.37	$50.42	$9.95	$48.29	$41.54	$6.76	$78.51	$55.44	$23.08	$79.96	$55.04	$24.92
2031	$60.89	$52.35	$8.54	$48.56	$43.26	$5.30	$79.43	$57.49	$21.93	$80.90	$57.09	$23.81
2032	$63.98	$54.62	$9.36	$51.39	$45.31	$6.09	$82.90	$59.88	$23.02	$84.41	$59.47	$24.94
2033	$66.51	$57.62	$8.89	$53.65	$48.08	$5.57	$85.82	$63.01	$22.80	$87.36	$62.59	$24.77
2034	$66.41	$59.72	$6.69	$53.29	$49.95	$3.34	$86.12	$65.24	$20.88	$87.69	$64.81	$22.88
2035	$67.99	$62.08	$5.91	$54.59	$52.08	$2.51	$88.10	$67.74	$20.36	$89.70	$67.30	$22.41
2036	$68.29	$65.97	$2.32	$54.62	$55.72	($1.10)	$88.80	$71.76	$17.04	$90.44	$71.31	$19.13

15 Year (2018 - 2032) Nominal levelized Price at 6.570% Discount Rate (1)

$/MWh	$34.51	$33.68	$0.83	$32.41	$28.76	$3.65	$37.91	$36.30	$1.61	$38.07	$36.21	$1.86

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 (2019 - 2033) Nominal levelized Price at 6.570% Discount Rate (1)

$/MWh	$37.32	$35.89	$1.43	$34.60	$30.61	$3.99	$41.59	$38.73	$2.86	$41.83	$38.62	$3.21

15 Year (2021 - 2035) Nominal levelized Price at 6.570% Discount Rate (1)

$/MWh	$43.03	$40.71	$2.33	$38.93	$34.65	$4.28	$49.32	$44.05	$5.27	$49.73	$43.88	$5.85

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

Year	Proposed Renewable Standard Base Load QF	Current Renewable Standard Base Load QF	Difference Renewable Standard Base Load QF	Proposed Renewable Standard Wind QF (2)	Current Renewable Standard Wind QF (2)	Difference Renewable Standard Wind QF (2)	Proposed Renewable Standard Fixed Solar QF	Current Renewable Standard Fixed Solar QF	Difference Renewable Standard Fixed Solar QF	Proposed Renewable Standard Tracking Solar QF	Current Renewable Standard Tracking Solar QF	Difference Renewable Standard Tracking Solar QF
2018	$20.53	$22.27	($1.74)	$20.08	$18.89	$1.19	$21.91	$23.82	($1.91)	$21.86	$23.82	($1.96)
2019	$21.70	$22.81	($1.11)	$21.23	$19.35	$1.87	$22.92	$24.38	($1.46)	$22.88	$24.39	($1.51)
2020	$24.23	$24.56	($0.33)	$23.73	$21.03	$2.71	$25.31	$26.30	($0.99)	$25.27	$26.30	($1.04)
2021	$40.24	$25.30	$14.93	$27.11	$21.65	$5.46	$50.61	$27.56	$23.05	$52.89	$27.56	$25.32
2022	$41.26	$28.00	$13.25	$27.79	$24.30	$3.49	$51.81	$29.81	$22.00	$54.14	$29.81	$24.33
2023	$42.25	$30.91	$11.34	$28.46	$27.14	$1.32	$52.95	$32.63	$20.32	$55.34	$32.63	$22.71
2024	$43.22	$31.94	$11.28	$29.09	$27.97	$1.11	$53.98	$35.24	$18.74	$56.43	$35.24	$21.19
2025	$44.24	$36.82	$7.42	$29.76	$32.88	($3.11)	$55.09	$38.57	$16.52	$57.61	$38.57	$19.03
2026	$45.25	$37.31	$7.93	$30.43	$33.28	($2.85)	$56.28	$39.00	$17.28	$58.85	$39.00	$19.85
2027	$46.26	$38.47	$7.79	$31.11	$34.35	($3.24)	$57.51	$40.10	$17.42	$60.14	$40.10	$20.04
2028	$47.28	$86.51	($39.23)	$31.79	$69.50	($37.71)	$58.70	$81.56	($22.85)	$61.39	$83.55	($22.16)
2029	$48.31	$88.55	($40.24)	$32.48	$71.15	($38.67)	$59.88	$83.34	($23.46)	$62.63	$85.39	($22.75)
2030	$49.36	$90.64	($41.29)	$33.17	$72.84	($39.66)	$61.15	$85.07	($23.92)	$63.96	$87.17	($23.21)
2031	$50.41	$92.80	($42.39)	$33.88	$74.58	($40.70)	$62.40	$87.04	($24.64)	$65.27	$89.18	($23.91)
2032	$51.47	$95.07	($43.60)	$34.59	$76.40	($41.82)	$63.68	$89.09	($25.40)	$66.61	$91.28	($24.67)
2033	$52.54	$97.36	($44.82)	$35.30	$78.26	($42.96)	$64.96	$91.03	($26.08)	$67.95	$93.28	($25.33)
2034	$53.63	$99.73	($46.09)	$36.04	$80.17	($44.13)	$66.31	$93.16	($26.85)	$69.36	$95.46	($26.10)
2035	$54.73	$102.12	($47.38)	$36.77	$82.08	($45.31)	$67.62	$95.50	($27.88)	$70.74	$97.86	($27.12)
2036	$55.84	$104.60	($48.76)	$37.51	$84.09	($46.58)	$68.96	$97.62	($28.67)	$72.14	$100.04	($27.90)

15 Year (2018 - 2032) Nominal levelized Price at 6.570% Discount Rate (1)

$/MWh	$38.54	$43.26	($4.71)	$27.84	$36.25	($8.41)	$46.85	$43.42	$3.43	$48.67	$43.91	$4.76

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 (2019 - 2033) Nominal levelized Price at 6.570% Discount Rate (1)

$/MWh	$41.05	$47.72	($6.68)	$28.98	$39.83	($10.85)	$50.26	$47.47	$2.79	$52.33	$48.08	$4.24

15 Year (2021 - 2035) Nominal levelized Price at 6.570% Discount Rate (1)

$/MWh	$46.16	$57.55	($11.39)	$31.05	$47.68	($16.63)	$57.45	$56.34	$1.11	$60.07	$57.23	$2.84

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
	(a)	(b)	(c)	(d)	(e)	(f)

UT N - 200 MW - SCCT Frame "F" x1 - East Side Resource (5,050')

Year	(a)	(b)	(c)	(d)	(e)	(f)
2016	$702	$51.73	$30.66	$7.53	$52.42	$104.15
2017		$52.66	$31.21	$7.67	$53.38	$106.04
2018		$53.71	$31.83	$7.82	$54.44	$108.15
2019		$54.95	$32.56	$8.00	$55.69	$110.64
2020		$56.41	$33.43	$8.21	$57.16	$113.57
2021		$57.90	$34.31	$8.43	$58.68	$116.58
2022		$59.36	$35.17	$8.64	$60.15	$119.51
2023		$60.78	$36.01	$8.85	$61.59	$122.37
2024		$62.20	$36.85	$9.06	$63.04	$125.24
2025		$63.64	$37.70	$9.27	$64.50	$128.14
2026		$65.09	$38.56	$9.48	$65.96	$131.05
2027		$66.52	$39.41	$9.69	$67.42	$133.94
2028		$67.96	$40.26	$9.90	$68.88	$136.84
2029		$69.45	$41.14	$10.12	$70.39	$139.84
2030		$70.96	$42.03	$10.34	$71.92	$142.88
2031		$72.47	$42.92	$10.56	$73.45	$145.92
2032		$73.99	$43.82	$10.78	$74.98	$148.97
2033		$75.53	$44.73	$11.00	$76.53	$152.06
2034		$77.09	$45.65	$11.23	$78.11	$155.20
2035		$78.67	$46.59	$11.46	$79.72	$158.39
2036		$80.27	$47.54	$11.69	$81.33	$161.60
2037		$81.89	$48.50	$11.93	$82.99	$164.88

Source: (a)(c)(d) Plant Costs - 2017 IRP - Table 6.1 & 6.2
(b) = (a) x Payment Factor
(e) = (d) x (8.76 x 33%) + (c)
(f) = (b) + (e)

	UT N - 200 MW - SCCT Frame "F" x1 - East Side Resource (5,050')		
	200	MW Plant capacity	MW
2016 $	$702	Plant capacity cost	$/kW
2016 $	$16.02	Fixed O&M & Capitalized O&M	$/kW-yr
2016 $	$14.64	Fixed Pipeline	$/kW-yr
2016 $	$30.66	Fixed O&M Including Fixed Pipeline & Capitalized C	$/kW-yr
2016 $	$7.53	Variable O&M and Other Costs	$/MWH
	7.373%	Payment Factor	
	33%	Capacity Factor	

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	Fuel Cost	IRP Resource Energy Cost	Total Avoided Costs
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/kW-yr	$/kW-yr	$/MMBtu	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Willamette Valley - 436 MW - CCCT Dry "G/H", 1x1 - West Side Resource (1,500')									
2016	$1,363	$98.90	$43.70	$2.02	$56.14	$155.04			
2017		$100.68	$44.49	$2.06	$57.18	$157.86			
2018		$102.70	$45.38	$2.10	$58.31	$161.01			
2019		$105.06	$46.42	$2.15	$59.66	$164.72			
2020		$107.85	$47.65	$2.21	$61.26	$169.11			
2021		$110.69	$48.90	$2.27	$62.88	$173.57			
2022		$113.48	$50.13	$2.33	$64.48	$177.96			
2023		$116.19	$51.33	$2.39	$66.05	$182.24			
2024		$118.91	$52.53	$2.45	$67.62	$186.53			
2025		$121.66	$53.74	$2.51	$69.20	$190.86			
2026		$124.43	$54.96	$2.57	$70.79	$195.22			
2027		$127.17	$56.17	$2.63	$72.37	$199.54			
2028		$129.93	$57.39	$2.69	$73.96	$203.89			
2029		$132.77	$58.65	$2.75	$75.59	$208.36			
2030		$135.65	$59.92	$2.81	$77.22	$212.87	$5.10	$32.69	$67.26
2031		$138.54	$61.20	$2.87	$78.87	$217.41	$5.09	$32.63	$67.93
2032		$141.44	$62.48	$2.93	$80.52	$221.96	$5.48	$35.13	$71.17
2033		$144.38	$63.78	$2.99	$82.19	$226.57	$5.78	$37.05	$73.84
2034		$147.36	$65.10	$3.05	$83.88	$231.24	$5.67	$36.34	$73.89
2035		$150.39	$66.44	$3.11	$85.59	$235.98	$5.82	$37.31	$75.63
2036		$153.45	$67.79	$3.17	$87.31	$240.76	$5.77	$36.99	$76.09
2037		$156.54	$69.16	$3.23	$89.05	$245.59	$6.15	$39.42	$79.30

Table 9
Total Cost of Displaceable Resources

Sources, Inputs and Assumptions

Source: (a)(c)(d)		Plant Costs - 2017 IRP - Table 6.1 & 6.2
	(b)	= (a) x 0.0725628795024555
	(e)	= (d) x (8.76 x 70.3%) + (c)
	(f)	= (b) + (e)
	(g)	Gas Price Forecast
	(h)	= 6410 x (g) / 1000
	(i)	= (f) / (8.76 x 'Capacity Factor') + (h)

Willamette Valley - 436 MW - CCCT Dry "G/H", 1x1 - West Side Resource (1,500')

CCCT Statistics	MW	Percent	Cap Cost	Fixed
CCCT (Dry "J" Adv 1x1)	385	88.3%	$1,484	$44.50
CCCT Duct Firing (Dry "J" Adv 1x1)	51	11.7%	$443	$37.67
Capacity Weighted	436	100.0%	$1,363	$43.70

CCCT Statistics	MW	CF	aMW	Percent	Variable	Heat Rate
CCCT (Dry "J" Adv 1x1)	385	78.0%	301	98.0%	$2.06	6,362
CCCT Duct Firing (Dry "J" Adv 1x1)	51	12.0%	6	2.0%	0.15	9,012
Energy Weighted	436	70.3%	307	100.0%	$2.02	6,410
						Rounded

	CCCT	Duct Firing	Plant Costs - 2017 IRP - Table 6.1 & 6.2
	385	51	MW Plant capacity
2016 $	$1,484	$443	Plant capacity cost
2016 $	$21.71	$5.39	Fixed O&M & Capitalized O&M
2016 $	$22.79	$32.28	Fixed Pipeline
	$44.50	$37.67	Fixed O&M Including Fixed Pipeline & Capitalized O&M ($/kW-Yr)
	$2.06	$0.15	Variable O&M and Other Costs
	6,362	9,012	Heat Rate in btu/kWh
	7.256%	7.256%	Payment Factor
	78.0%	12.0%	Capacity Factor
		70.3%	Energy Weighted Capacity Factor
		100.0%	Capacity Factor - On-peak 70.3% / 56.0% (percent of hours on-peak)

Company Official Inflation Forecast - Dated March 2018

2015	1.1%	2021	2.6%	2027	2.2%	2033	2.1%
2016	1.3%	2022	2.5%	2028	2.2%	2034	2.1%
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%

Table 10
Gas Price Forecast
$/MMBtu

Year	Burner tip West Side Gas Fuel Cost
2030	$5.10
2031	$5.09
2032	$5.48
2033	$5.78
2034	$5.67
2035	$5.82
2036	$5.77

Source
Offical Market Price Forecast dated March 2018

Table 11
Integration Cost

Year	Wind Integration Cost $/MWh	Solar Integration Cost $/MWh
2016	$0.57	$0.60
2017	$0.58	$0.61
2018	$0.59	$0.62
2019	$0.60	$0.63
2020	$0.62	$0.65
2021	$0.64	$0.67
2022	$0.66	$0.69
2023	$0.68	$0.71
2024	$0.70	$0.73
2025	$0.72	$0.75
2026	$0.74	$0.77
2027	$0.76	$0.79
2028	$0.78	$0.81
2029	$0.80	$0.83
2030	$0.82	$0.85
2031	$0.84	$0.87
2032	$0.86	$0.89
2033	$0.88	$0.91
2034	$0.90	$0.93
2035	$0.92	$0.95
2036	$0.94	$0.97
2037	$0.96	$0.99

Note: 2017 IRP Volume II-Appendix F

Official Inflation Forecast Dated 2018 1st Quarter					
2015	1.1%	2023	2.4%	2031	2.1%
2016	1.3%	2024	2.3%	2032	2.1%
2017	1.8%	2025	2.3%	2033	2.1%
2018	2.0%	2026	2.3%	2034	2.1%
2019	2.3%	2027	2.2%	2035	2.1%
2020	2.7%	2028	2.2%	2036	2.0%
2021	2.6%	2029	2.2%	2037	2.0%
2022	2.5%	2030	2.2%	2038	2.0%

Table 12
2017 IRP Wyoming Wind Resource
41% Capacity Factor

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/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)
2017 IRP Wyoming Wind Resource - 41% Capacity Factor								
2016	$1,637	$115.69	$37.57	$42.46	$0.65	($17.76)	$25.35	$0.57
2017		$117.78	$38.24	$43.23	$0.66	($18.08)	$25.81	$0.58
2018		$120.14	$39.01	$44.10	$0.67	($18.44)	$26.33	$0.59
2019		$122.91	$39.91	$45.11	$0.69	($18.86)	$26.94	$0.60
2020		$126.18	$40.97	$46.31	$0.71	($19.36)	$27.66	$0.62
2021		$129.50	$42.05	$47.53	$0.73	($19.87)	$28.39	$0.64
2022		$132.76	$43.11	$48.73	$0.75	($20.37)	$29.11	$0.66
2023		$135.93	$44.14	$49.89	$0.77	($20.86)	$29.80	$0.68
2024		$139.11	$45.17	$51.06	$0.79	($21.35)	$30.50	$0.70
2025		$142.33	$46.21	$52.24	$0.81	($21.84)	$31.21	$0.72
2026		$145.57	$47.26	$53.43	$0.83	($22.34)	$31.92	$0.74
2027		$148.78	$48.30	$54.61	$0.85	($22.83)	$32.63	$0.76
2028		$152.00	$49.35	$55.79	$0.87	($23.32)	$33.34	$0.78
2029		$155.33	$50.43	$57.01	$0.89	($23.83)	$34.07	$0.80
2030		$158.70	$51.53	$58.25	$0.91	($24.35)	$34.81	$0.82
2031		$162.08	$52.63	$59.49	$0.93	($24.87)	$35.55	$0.84
2032		$165.47	$53.73	$60.74	$0.95	($25.39)	$36.30	$0.86
2033		$168.91	$54.85	$62.00	$0.97	($25.92)	$37.05	$0.88
2034		$172.40	$55.98	$63.28	$0.99	($26.46)	$37.81	$0.90
2035		$175.94	$57.13	$64.58	$1.01	($27.00)	$38.59	$0.92
2036		$179.52	$58.29	$65.89	$1.03	($27.55)	$39.37	$0.94
2037		$183.14	$59.46	$67.22	$1.05	($28.11)	$40.16	$0.96

Sources, Inputs and Assumptions

Source:	(c)(f)	Plant Costs 2017 IRP (Table 6.2) in $2016
	(a)	Plant capacity cost
	(b)	= (a) x 0.0706748586244695
	(d)	= ((b) + (c)) / (8.76 x 41.2%)
	(g)	= (d) + (f)
	(h)	2017 IRP Volume II-Appendix F

2017 IRP Wyoming Wind Resource - 41% Capacity Factor

	Wind	Cost and Input Assumptions		
2016 $	$1,637	Plant capacity cost	$/kW-yr	IRP2017 Chapter 8, page 220
2016 $	$37.57	Fixed O&M, plus on-going capital cost	$/kW-yr	
2016 $	0.57	Integration Cost		
2016 $	$0.65	Variable O&M	$/MWH	
2016 $	($17.76)	Tax Credit $/MWh	$/MWH	
	15.8%	East Wind Capacity Contribution		
	7.067%	Payment Factor		
	41%	Capacity Factor		IRP2017 Chapter 8, page 220

Official Inflation Forecast Dated 2018 1st Quarter

2015	1.1%	2021	2.6%	2027	2.2%	2033	2.1%
2016	1.3%	2022	2.5%	2028	2.2%	2034	2.1%
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%

Table 13
2017 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)
2018	$26.33	1.1476	0.8121	$30.21	$21.38
2019	$26.94	1.1319	0.8317	$30.50	$22.41
2020	$27.66	1.1150	0.8531	$30.84	$23.60
2021	$28.39	1.1047	0.8668	$31.36	$24.61
2022	$29.11	1.1001	0.8727	$32.02	$25.40
2023	$29.80	1.0948	0.8796	$32.63	$26.22
2024	$30.50	1.0846	0.8912	$33.08	$27.18
2025	$31.21	1.0773	0.9013	$33.62	$28.13
2026	$31.92	1.0741	0.9052	$34.28	$28.89
2027	$32.63	1.0734	0.9064	$35.02	$29.57
2028	$33.34	1.0703	0.9110	$35.68	$30.37
2029	$34.07	1.0655	0.9165	$36.30	$31.23
2030	$34.81	1.0641	0.9180	$37.04	$31.95
2031	$35.55	1.0619	0.9211	$37.75	$32.74
2032	$36.30	1.0608	0.9222	$38.50	$33.47
2033	$37.05	1.0587	0.9251	$39.22	$34.27
2034	$37.81	1.0590	0.9252	$40.04	$34.98
2035	$38.59	1.0569	0.9272	$40.79	$35.78
2036	$39.37	1.0556	0.9290	$41.56	$36.57

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 2

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – JULY 2018

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – JULY 2018

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 June 01, 2017.

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 (2018 through 2029) period; and (2) Standard non-renewable resource deficiency (2030 and beyond) period. During the non-renewable resource sufficiency period (2018 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 2018 through 2020 and the standard renewable resource deficiency period starts in 2021. During the renewable resource sufficiency period (2018 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 current CCCT proxy resource used to set standard avoided cost rates beginning in 2030 is a west side CCCT from the 2017 IRP.[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 on-peak and off-peak prices of a renewable proxy resource from the 2017 IRP. The standard renewable on-peak price also includes a capacity adder calculated based on the fixed costs of a thermal proxy CCCT 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] 436 MW CCCT (Dry "G/H" 1x1) - West Side Resource (1500') –available in 2030 as listed in Tables 6.1 and 6.2 of the 2017 IRP. Fuel costs are from the Company's March 2018 Official Forward Price Curve (1803 OFPC).

[2] SCCT Frame ("F"x1) – East Side Resource (5,050'), as listed in Tables 6.1 and 6.2 of the 2017 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 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.

Gas Price Forecast

Gas prices used in this filing utilize the Company's March 2018 Official Forward Price Curve (1803 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 plant from 2017 IRP. 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 2018-2029. 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 CCCT 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 2017-2029. 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 the CCCT proxy (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 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 2017-2029. 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 a thermal proxy CCCT (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 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 2017-2020, 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. Starting in 2021, the standard renewable on-peak price also includes a capacity adder calculated based on the fixed costs of the CCCT proxy (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 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 2017-2020. 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. Starting in 2021, the standard renewable on-peak price also includes a capacity adder calculated based on the fixed costs of the CCCT proxy CCCT (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 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 2017-2020. 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. Starting in 2021, the standard renewable on-peak price also includes a capacity adder calculated based on the fixed costs of a thermal proxy CCCT (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 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.**

Docket UM 1729 / 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').	Table 8.17 – 2017 IRP Preferred Portfolio, page 244.
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	Table 8.17 – 2017 IRP Preferred Portfolio, page 244 and Plant costs 2017 IRP Chapter 8, Page 220

Docket UM 1729 / 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) March 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 March 2018 OFPC was the most recent curve available at the time of this filing. Currently effective rates were based on the March 2017 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 Oregon Schedule 37 Avoided Cost Study work paper.	-
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 March 2018 OFPC was the most recent curve available that would have been used in the Company's April 2018 update. Currently approved rates were based on March 2017 OFPC. Refer to the spreadsheet entitled "13_MFR - II.Gas Price Forecast_20180425" for the comparison of the gas price forecast. Refer to the files entitled "201703 OFPC - Environmental" and "201803 OFPC - Environmental" for the March 2017 OFPC and March 2018 OFPC carbon tax assumptions.	-

Docket UM 1729 / 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 Oregon Schedule 37 Avoided Cost Study work paper.	Flexible Reserve Study from 2017 IRP, 2017 IRP Volume II-Appendix F, Table F.2 on Page 75

Docket UM 1729 / 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 70.3 percent. Refer to Table 9 of Oregon Schedule 37 Avoided Cost Study work paper.	2017 IRP Table 6.1 and Table 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 Oregon Schedule 37 Avoided Cost Study work paper.	-
3.	Provide the assumed heat rate. Include assumptions to account for elevation / temperature, and cooling method.	Refer to Table 9 of Oregon Schedule 37 Avoided Cost Study work paper.	2017 IRP Table 6.1 and Table 6.2.
4.	List the costs assumed for interconnection facilities.	-	2017 IRP Table 6.1 and Table 6.2.
5.	List the components of transmission costs used and their respective values.	-	2017 IRP Table 6.1 and Table 6.2.
6.	List the tax assumptions used.	-	2017 IRP Table 6.1 and Table 6.2.

Docket UM 1729 / 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 41% CF available in 2021 from the 2017 IRP. Refer to Table 12 of Oregon Schedule 37 Avoided Cost Study work paper.	Table 8.17 – 2017 IRP Preferred Portfolio, page 244 and Plant costs 2017 IRP Chapter 8, Page 220
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.	-	Table 6.2 – 2017 IRP - Plant Costs (2016$).
4.	List the components of transmission costs used and their respective values.	-	Table 6.2 – 2017 IRP - Plant Costs (2016$).
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 $17.76/MWh (in 2016$) escalated by inflation rate). Refer to Table 12 of Oregon Schedule 37 Avoided Cost Study work paper.	Table 6.2 – 2017 IRP - Plant Costs (2016$).
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

California CO_2: No Update

California cap-and-trade policy assumptions in Aurora

- Program start date was 2012 with 2013 being the first compliance year for power plants.
- In the absence of a Federal CO_2 tax, California CO_2 is assumed to continue post 2021 in accordance with current program guidelines.
- Assumed California 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.

111(d) Policy: No Update

- **On August 3, 2015, the Environmental Protection Agency (EPA) released its finalized Clean Power Plan (CPP) (aka 111(d)) setting state-specific interim and final goals for carbon dioxide emissions beginning 2022. By 2030, each state* is to be fully compliant with EPA's calculated goal and maintain it post 2030. The Rule's objective is a 32% reduction in 2005 power sector emissions by 2030. *Note: Vermont is exempt from 111(d).**

- **EPA used three building blocks to define the "best system of emission reduction" (BSER). The three building blocks include:**
  - Coal plant efficiency improvements of 2.1% - 4.3%.
  - Increased utilization of natural gas-fueled units to average 75% of net summer capacity.
  - Increased deployment of zero-emitting resources.

- **Using these building blocks the EPA calculated state-specific goals via three different formats, allowing each state to choose its format:**
  - A rate-based goal – CO_2 pounds per MWh.
  - A mass-based goal – short tons of CO_2.
  - A mass-based goal with a new source complement – short tons of $CO_{2.}$

- **States must develop plans (states can also enter into multi-state plans) to meet the established goal. State compliance mechanisms are flexible and do not need to be based on the three building blocks used to establish BSER. Plans are to be submitted to the EPA in the 2016-2018 timeframe. In developing the September 2016 OFPC, the 111(d) regulation was modeled with the following assumptions:**
  - No coal unit efficiency improvements are implemented
  - Renewable generation is tracked by renewable energy credit (REC) ownership, not by state boundary
  - New natural gas combined cycle units (NGCC) are regulated under 111(d) in all states
  - Energy efficiency acquisition as assumed in EPA's calculation of emission rate goals is achievable
  - WECC-wide compliance targets are assumed (excluding California), using the sum of state allowance allocations with new source complement.

111(d) Policy (cont.): No Update

- On March 28, 2017, President Trump issued an Executive Order directing the EPA to review the Clean Power Plan and, if appropriate, suspend, revise or rescind the Clean Power Plan, as well as related rules and agency actions. We will continue to follow activities related to this Executive Order and update the Aurora model as appropriate.

Federal CO_2 Allowance Pricing: No Update

Federal CO_2 allowance pricing assumptions in Aurora

- With the addition of modeled impacts of EPA's 111(d) Clean Power Act, there is no assumed Federal CO_2 allowance pricing.

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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.

Gas Price Forecast Comparison

	OFPC March 2018 West Side Gas	OFPC March 2017 West Side Gas	Change	% Change
2030	5.10	4.99	0.11	2%
2031	5.09	5.22	(0.13)	-2%
2032	5.48	5.50	(0.02)	0%
2033	5.78	5.89	(0.11)	-2%
2034	5.67	6.14	(0.47)	-8%
2035	5.82	6.43	(0.61)	-9%