

August 22, 2016

VIA ELECTRONIC FILING

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

Attn: Filing Center

**Re: UM 1729 – Schedule 37 Avoided Cost Purchases from Eligible Qualifying Facilities
– Compliance Filing**

In compliance with Order No. 16-307 (the Order), PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits the enclosed Schedule 37 standard non-renewable and standard renewable avoided cost prices for purchases from eligible qualifying facilities. Per Order No. 16-307, the effective date of the new Schedule 37 pricing is August 24, 2016.¹ The Order directs the Company to file amended Schedule 37 prices based on “renewable and non-renewable deficiency periods beginning 2028, cost and performance data from its acknowledged 2015 Integrated Resource Plan, and updated gas and electricity prices as required in an annual update”.²

The enclosed avoided cost prices comply with the Order by including cost and performance data from the acknowledged 2015 Integrated Resource Plan (IRP) and updated gas and electricity prices using the Company’s March 2016 Official Forward Price Curve. Additionally, the updated Schedule 37 prices include a 2028 resource deficiency date for both standard non-renewable and standard renewable price streams. For the standard renewable prices stream, PacifiCorp assumes the proxy resource for a 2028 deficiency period is a Wyoming wind resource using cost and performance assumptions reflected in the acknowledged 2015 IRP³. This complies with the Order and aligns with PacifiCorp’s strategy to defer Oregon renewable portfolio standard (RPS) compliance needs to at least 2028 when planned coal unit retirements will open existing transmission capacity providing access to low cost renewable resource zones within PacifiCorp’s system. With the assumed retirement of the Dave Johnston plant (~760 MW) at the end of 2027, as assumed in the acknowledged 2015 IRP, PacifiCorp would fulfill any incremental RPS compliance need with wind resources located in eastern Wyoming, which can operate at favorable capacity factors relative to other renewable resource alternatives assumed in the 2015 IRP. Table 6.2 of the 2015 IRP presents levelized costs for renewable resource options considered in the acknowledged 2015 IRP. This data confirms that if sufficient

¹ PacifiCorp “shall file an amended Schedule 37, with prices to be effective two business days after filing” Order No. 16-307, Docket No. UM 1729 (Aug. 18, 2016).

² *Id.*

³ The Company’s acknowledged 2015 IRP can be found at the following link:
<https://www.pacificpower.net/about/irp.html>.

Public Utility Commission of Oregon

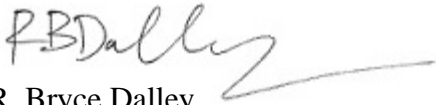
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transmission is available, as would be the case with the retirement of the Dave Johnston plant, that Wyoming wind resources are the least cost renewable resource option and, therefore, the Wyoming wind resource is the appropriate proxy resource to use for an assumed 2028 deficiency period.

UM 1729 is a non-contested case, and data requests or other discovery are not permitted. Informal inquiries about this filing may be directed to Natasha Siores at (503) 813-6583.

Sincerely,

A handwritten signature in cursive script, appearing to read "R. Bryce Dalley", with a long horizontal flourish extending to the right.

R. Bryce Dalley
Vice President, Regulation
Enclosures

REVISED TARIFF SHEETS
STANDARD AVOIDED COST RATE

**AVOIDED COST PURCHASES FROM
ELIGIBLE QUALIFYING FACILITIES**

Available

To owners of Qualifying Facilities making sales of electricity to the Company in the State of Oregon.

Applicable

- For power purchased from Base Load and Wind Qualifying Facilities with a nameplate capacity of 10,000 kW or less or that, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a nameplate capacity of 10,000 kW or less. (C)
- For power purchased Fixed and Tracking Solar Qualifying Facilities with a nameplate capacity of 3,000 kW or less or that, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a nameplate capacity of 3,000 kW or less. (N)

Owners of these Qualifying Facilities will be required to enter into a written power sales contract with the Company.

Definitions

Cogeneration Facility

A facility which produces electric energy together with steam or other form of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

Qualifying Facilities

Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Qualifying Electricity

Electricity that meets the requirements of “qualifying electricity” set forth in the Oregon Renewable Portfolio Standards: ORS 469A.010, 469A.020, and 469A.025.

Renewable Qualifying Facility

A Qualifying Facility that generates Qualifying Electricity.

Wind Qualifying Facility

A Renewable Qualifying Facility that generates Qualifying Electricity using wind as its motive force.

Baseload Renewable Qualifying Facility

A Renewable Qualifying Facility that generates Qualifying Electricity using any qualifying resource other than wind or solar.

Small Power Production Facility

A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.

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Definitions (continued)**On-Peak Hours or Peak Hours**

On-Peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays.

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Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

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Off-Peak Hours

All hours other than On-Peak.

Excess Output

Excess Output shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Nameplate Capacity. PacifiCorp shall pay Seller the Off-Peak Price as described and calculated under pricing option 4 (Non-Firm Market Index Avoided Cost Price) for all Excess Output.

Same Site

Generating facilities are considered to be located at the same site as the QF for which qualification for the standard rates and standard contract is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for the standard rates and standard contract is sought.

Person(s) or Affiliated Person(s)

A natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Shared Interconnection and Infrastructure

QFs otherwise meeting the separate ownership test and thereby qualified for entitlement to the standard rates and standard contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for the standard rates and standard contract so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved standard contract.

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Definitions (continued)**On-Peak Hours or Peak Hours**

On-Peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays.

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page 1

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

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Off-Peak Hours

All hours other than On-Peak.

Excess Output

Excess Output shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Nameplate Capacity. PacifiCorp shall pay Seller the Off-Peak Price as described and calculated under pricing option 4 (Non-Firm Market Index Avoided Cost Price) for all Excess Output.

Same Site

Generating facilities are considered to be located at the same site as the QF for which qualification for the standard rates and standard contract is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for the standard rates and standard contract is sought.

Person(s) or Affiliated Person(s)

A natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

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Dispute Resolution

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and standard contract.

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Any dispute concerning a QF's entitlement to the standard rates and standard contract shall be presented to the Commission for resolution.

Self Supply Option

Owner shall elect to sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp or sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of the power purchase agreement and the appropriate retail service.

Pricing Options

1. Standard Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. Standard Fixed Avoided Cost Prices are available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price. The Standard Fixed Avoided Cost pricing option is available to all Qualifying Facilities. The Standard Fixed Avoided Cost Price for Wind Qualifying Facilities will reflect integration costs as set forth on page 5.

2. Renewable Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Renewable Qualifying Facility and the Company and will not change during the term of the contract. Renewable Fixed Avoided Cost Prices are available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price. The Renewable Fixed Avoided Cost pricing option is available only to Renewable Qualifying Facilities. A Renewable Qualifying Facility choosing the Renewable Fixed Avoided Cost pricing option must cede all Green Tags generated by the facility, as defined in the standard contract, to the Company during the Renewable Resource Deficiency Period identified on page 8, except that a Renewable Qualifying Facility retains ownership of all Environmental Attributes generated by the facility, as defined in the standard contract, during the Renewable Resource Sufficiency Period identified on page 8 and during any period after the first 15 years of a longer term contract (up to 20 years).

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3. Firm Market Indexed Avoided Cost Prices

Firm Market Index Avoided Cost Prices are available to Qualifying Facilities that contract to deliver firm power. Monthly On-Peak / Off-Peak prices paid are a blending of Intercontinental Exchange (ICE) Day Ahead Power Price Report at market hubs for On-Peak and Off-Peak prices. The monthly blending matrix is available upon request.

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Pricing Options (continued)

4. Non-Firm Market Index Avoided Cost Prices

Non-Firm Market Index Avoided Cost Prices are available to Qualifying Facilities that do not elect to provide firm power. Qualifying Facilities taking this option will have contracts that do not include minimum delivery requirements, default damages for construction delay or, for under delivery or early termination, or default security for these purposes. Monthly On-Peak / Off-Peak prices paid are 93 percent of a blending of ICE Day Ahead Power Price Report at market hubs for On-Peak and Off-Peak firm index prices. The monthly blending matrix is available upon request. The Non-Firm Market Index Avoided Cost pricing option is available to all Qualifying Facilities. The Non-Firm Market Index Avoided Cost Price for Wind Qualifying Facilities will reflect integration costs.

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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.

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**AVOIDED COST PURCHASES FROM
 ELIGIBLE QUALIFYING FACILITIES**
Avoided Cost Prices
Standard Fixed Avoided Cost Prices for Base Load and Wind QF

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)
2016	2.34	1.99	2.03	1.67
2017	2.63	2.17	2.31	1.85
2018	2.82	2.30	2.50	1.97
2019	2.94	2.38	2.61	2.05
2020	3.10	2.51	2.76	2.17
2021	3.30	2.71	2.95	2.36
2022	3.60	3.00	3.24	2.64
2023	4.03	3.37	3.66	3.00
2024	4.44	3.73	4.07	3.36
2025	4.66	3.93	4.28	3.55
2026	4.84	4.09	4.45	3.70
2027	5.06	4.27	4.66	3.87
2028	6.23	3.25	3.59	2.84
2029	6.39	3.34	3.69	2.92
2030	6.66	3.55	3.91	3.12
2031	6.82	3.64	4.01	3.20
2032	6.99	3.74	4.12	3.29
2033	7.19	3.86	4.25	3.40
2034	7.38	3.98	4.37	3.51
2035	7.56	4.09	4.49	3.61

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Effective for service on and after August 24, 2016

**AVOIDED COST PURCHASES FROM
 ELIGIBLE QUALIFYING FACILITIES**

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Avoided Cost Prices (Continued)
Standard Fixed Avoided Cost Prices for Fixed and Tracking Solar QF

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Deliveries During Calendar Year	Fixed Solar QF (3)		Tracking Solar QF (3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(e)	(f)	(g)	(h)
2016	2.34	1.99	2.34	1.99
2017	2.63	2.17	2.63	2.17
2018	2.82	2.30	2.82	2.30
2019	2.94	2.38	2.94	2.38
2020	3.10	2.51	3.10	2.51
2021	3.30	2.71	3.30	2.71
2022	3.60	3.00	3.60	3.00
2023	4.03	3.37	4.03	3.37
2024	4.44	3.73	4.44	3.73
2025	4.66	3.93	4.66	3.93
2026	4.84	4.09	4.84	4.09
2027	5.06	4.27	5.06	4.27
2028	4.21	3.25	4.34	3.25
2029	4.32	3.34	4.46	3.34
2030	4.55	3.55	4.69	3.55
2031	4.66	3.64	4.81	3.64
2032	4.78	3.74	4.93	3.74
2033	4.93	3.86	5.08	3.86
2034	5.07	3.98	5.22	3.98
2035	5.21	4.09	5.36	4.09

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- (1) Capacity Contribution to Peak for Avoided Proxy Resource and Base Load Qualifying Facility resource are assumed 100%.
- (2) The standard avoided cost price for wind is reduced by an integration charge of \$3.06/MWh (\$2014). If Wind Qualifying Facility is not in PacifiCorp's balancing authority area, then no reduction is required.
- (3) Standard Resource Sufficiency Period ends December 31, 2027 and Standard Resource Deficiency Period begins January 1, 2028.

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**AVOIDED COST PURCHASES FROM
 ELIGIBLE QUALIFYING FACILITIES**
Avoided Cost Prices (Continued)
Renewable Fixed Avoided Cost Prices for Base Load and Wind QF

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)
2016	2.34	1.99	2.03	1.67
2017	2.63	2.17	2.31	1.85
2018	2.82	2.30	2.50	1.97
2019	2.94	2.38	2.61	2.05
2020	3.10	2.51	2.76	2.17
2021	3.30	2.71	2.95	2.36
2022	3.60	3.00	3.24	2.64
2023	4.03	3.37	3.66	3.00
2024	4.44	3.73	4.07	3.36
2025	4.66	3.93	4.28	3.55
2026	4.84	4.09	4.45	3.70
2027	5.06	4.27	4.66	3.87
2028	10.23	6.60	7.59	6.19
2029	10.43	6.74	7.74	6.32
2030	10.68	6.87	7.93	6.44
2031	10.90	7.03	8.09	6.59
2032	11.13	7.20	8.26	6.76
2033	11.37	7.37	8.43	6.92
2034	11.61	7.55	8.61	7.08
2035	11.83	7.76	8.76	7.28

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**AVOIDED COST PURCHASES FROM
 ELIGIBLE QUALIFYING FACILITIES**
Avoided Cost Prices (Continued)
Renewable Fixed Avoided Cost Prices for Fixed and Tracking Solar QF

Deliveries During Calendar Year	Fixed Solar QF (1,4)		Tracking Solar QF (1,4)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(e)	(f)	(g)	(h)
2016	2.34	1.99	2.34	1.99
2017	2.63	2.17	2.63	2.17
2018	2.82	2.30	2.82	2.30
2019	2.94	2.38	2.94	2.38
2020	3.10	2.51	3.10	2.51
2021	3.30	2.71	3.30	2.71
2022	3.60	3.00	3.60	3.00
2023	4.03	3.37	4.03	3.37
2024	4.44	3.73	4.44	3.73
2025	4.66	3.93	4.66	3.93
2026	4.84	4.09	4.84	4.09
2027	5.06	4.27	5.06	4.27
2028	8.20	6.60	8.34	6.60
2029	8.37	6.74	8.51	6.74
2030	8.57	6.87	8.71	6.87
2031	8.74	7.03	8.88	7.03
2032	8.93	7.20	9.07	7.20
2033	9.11	7.37	9.26	7.37
2034	9.31	7.55	9.46	7.55
2035	9.47	7.76	9.63	7.76

- (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, the Renewable Resource Sufficiency Period ends December 31, 2017, and the Renewable Resource Deficiency Period begins January 1, 2018.
- (2) During the Renewable Resource Deficiency Period, the renewable avoided cost price for a Wind Qualifying Facility will be adjusted by adding the difference between the avoided integration costs and the Qualifying Facility's integration costs. If the Wind Qualifying Facility is in PacifiCorp's Balancing Authority Area (BAA), the adjustment is zero (integration costs cancel each other out). If the Wind Qualifying Facility is not in PacifiCorp's BAA, the renewable avoided cost price will be increased by avoided integration charge of \$3.06/MWh (\$2014).
- (3) During Renewable Resource Sufficiency Period, the renewable avoided cost price for a Wind Qualifying Facility is reduced by an integration charge of \$3.06/MWh (\$2014) for Wind Qualifying Facilities located in PacifiCorp's BAA (in-system). If a Wind Qualifying Facility is not in PacifiCorp's BAA, the renewable avoided cost price will be increased by avoided integration charge of \$3.06/MWh (\$2014).
- (4) During the Renewable Resource Deficiency Period, the renewable avoided cost price for Base Load, Fixed Solar and Tracking Solar is increased by an integration charge of \$3.06/MWh (\$2014).

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Effective for service on and after August 24, 2016

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Qualifying Facilities Contracting Procedure

Interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (PacifiCorp Commercial and Trading).

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It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to allow time for studies, negotiation of agreements, engineering, procurement, and construction of the required interconnection facilities. Early application for interconnection will help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

1. Eligible Qualifying Facilities

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APPLICATION: To owners of eligible existing or proposed QFs with a design capacity less than or equal to 10,000 kW for Base Load and Wind QF resources and less than or equal to 3,000 kW for Solar QF resources who desire to make sales to the Company in the state of Oregon. Such owners will be required to enter into a written power purchase agreement with the Company pursuant to the procedures set forth below.

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(C)**I. Process for Completing a Power Purchase Agreement****A. Communications**

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements should be directed in writing as follows:

PacifiCorp
Manager-QF Contracts
825 NE Multnomah St, Suite 600
Portland, Oregon 97232

The Company will respond to all such communications in a timely manner. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company will respond in a timely manner following receipt of all required information.

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B. Procedures

1. The Company's approved generic or standard form power purchase agreements may be obtained from the Company's website at www.pacificorp.com, or if the owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.
2. In order to obtain a project specific draft power purchase agreement the owner must provide in writing to the Company, general project information required for the completion of a power purchase agreement, including, but not limited to:
 - (a) demonstration of ability to obtain QF status;
 - (b) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
 - (c) generation technology and other related technology applicable to the site;
 - (d) proposed site location;
 - (e) schedule of monthly power deliveries;
 - (f) calculation or determination of minimum and maximum annual deliveries;
 - (g) motive force or fuel plan;
 - (h) proposed on-line date and other significant dates required to complete the milestones;
 - (i) proposed contract term and pricing provisions as defined in this Schedule (i.e., standard fixed price, renewable fixed price);
 - (j) status of interconnection or transmission arrangements;
 - (k) point of delivery or interconnection;
3. The Company shall provide a draft power purchase agreement when all information described in Paragraph 2 above has been received in writing from the QF owner. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Public Utility Commission of Oregon in this Schedule 37.
4. If the owner desires to proceed with the power purchase agreement after reviewing the Company's draft power purchase agreement, it may request in writing that the Company prepare a final draft power purchase agreement. In connection with such request, the owner must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft power purchase agreement. Within 15 business days following receipt of all information requested by the Company in this paragraph 4, the Company will provide the owner with a final draft power purchase agreement.

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B. Procedures (continued)

5. After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

6. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company's execution a completely executed copy will be returned to the owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

II. Process for Negotiating Interconnection Agreements

[NOTE: Section II applies only to QFs connecting directly to PacifiCorp's electrical system. An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.]

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into an interconnection agreement that governs the physical interconnection of the project to the Company's transmission or distribution system. The Company's obligation to make purchases from a QF is conditioned upon the QF completing all necessary interconnection arrangements. It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (including but not limited to PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (including but not limited to PacifiCorp's Commercial and Trading Group).

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II. Process for Negotiating Interconnection Agreements (continued)

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A. Communications

Initial communications regarding interconnection agreements should be directed to the Company in writing as follows:

PacifiCorp
Director – Transmission Services
825 NE Multnomah St, Suite 1600
Portland, Oregon 97232

Based on the project size and other characteristics, the Company will direct the QF owner to the appropriate individual within the Company's transmission function who will be responsible for negotiating the interconnection agreement with the QF owner. Thereafter, the QF owner should direct all communications regarding interconnection agreements to the designated individual, with a copy of any written communications to the address set forth above.

B. Procedures

Generally, the interconnection process involves (1) initiating a request for interconnection, (2) undertaking studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) executing an interconnection agreement to address facility construction, testing, acceptance, ownership, operation and maintenance issues. Consistent with PURPA and Oregon Public Utility Commission regulations, the owner is responsible for all interconnection costs assessed by the Company on a nondiscriminatory basis. For interconnections impacting the Company's Transmission and Distribution System, the Company will process the interconnection application through PacifiCorp Transmission Services.

(M)

APPENDIX 1

**PACIFIC POWER
AVOIDED COST CALCULATION**

**STANDARD RATES FOR AVOIDED COST PURCHASES FROM
ELIGIBLE QUALIFYING FACILITIES**

OREGON – AUGUST 2016

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

Year	Standard Avoided Resource		Base Load QF Resource		
	Capacity Price \$/kW-yr (a)	Capacity Cost Allocated to On-Peak Hours (\$/MWh) (b)	Energy Only Price \$/MWh (c)	On-Peak \$/MWh (d)	Off-Peak \$/MWh (e)
		(a)/(8.76 x 100.0% x 57%)		(b) + (c)	= (c)
2016				\$23.43	\$19.86
2017				\$26.30	\$21.68
2018				\$28.22	\$22.97
2019				\$29.44	\$23.80
2020				\$30.99	\$25.14
2021				\$33.03	\$27.14
2022				\$35.96	\$30.03
2023				\$40.26	\$33.69
2024				\$44.43	\$37.30
2025				\$46.61	\$39.32
2026				\$48.41	\$40.90
2027				\$50.57	\$42.74
2028	\$149.06	\$29.85	\$32.45	\$62.30	\$32.45
2029	\$152.18	\$30.48	\$33.37	\$63.85	\$33.37
2030	\$155.56	\$31.15	\$35.46	\$66.61	\$35.46
2031	\$158.99	\$31.84	\$36.37	\$68.21	\$36.37
2032	\$162.49	\$32.54	\$37.35	\$69.89	\$37.35
2033	\$166.05	\$33.26	\$38.59	\$71.85	\$38.59
2034	\$169.68	\$33.98	\$39.77	\$73.75	\$39.77
2035	\$173.39	\$34.73	\$40.88	\$75.61	\$40.88
		Market Based Prices 2016 through 2027			

(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) 100.0% is the on-peak capacity factor of the Proxy Resource
- (c) 57.0% is the percent of all hours that are on-peak
- (c) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (d) 2016-2027 On-Peak Blended Market Prices for QF resource
- (e) 2016-2027 Off-Peak Blended Market Prices for QF resource

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

Year	Standard Avoided Resource			Tracking Solar QF			
	Capacity Price \$/kW-yr (a)	Capacity Cost Allocated to On-Peak Hours (\$/MWh) (b)	Energy Only Price \$/MWh (c)	Capacity Contribution (d)	Capacity Payment On-Peak Hours \$/MWh (e)	On-Peak \$/MWh (f)	Off-Peak \$/MWh (g)
		(a) / (8.76 x 100.0% x 57%)		= (d)	= (b) * (d)	= (c) + (e)	= (c)
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028	\$149.06	\$29.85	\$32.45	36.70%	\$10.95	\$43.40	\$32.45
2029	\$152.18	\$30.48	\$33.37	36.70%	\$11.19	\$44.56	\$33.37
2030	\$155.56	\$31.15	\$35.46	36.70%	\$11.43	\$46.89	\$35.46
2031	\$158.99	\$31.84	\$36.37	36.70%	\$11.69	\$48.06	\$36.37
2032	\$162.49	\$32.54	\$37.35	36.70%	\$11.94	\$49.29	\$37.35
2033	\$166.05	\$33.26	\$38.59	36.70%	\$12.21	\$50.80	\$38.59
2034	\$169.68	\$33.98	\$39.77	36.70%	\$12.47	\$52.24	\$39.77
2035	\$173.39	\$34.73	\$40.88	36.70%	\$12.75	\$53.63	\$40.88
		Market Based Prices 2016 through 2027					

Columns

- (a) Full fixed cost of a proxy CCCT less capitalized energy
- (b) 100.0% is the on-peak capacity factor of the Proxy Resource
57.0% is the percent of all hours that are on-peak
- (c) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (d) Peak Capacity Contribution values for renewables (% of nameplate capacity), 2015 IRP
(2015 IRP Volume II-Appendix N, Table N.1, page 405)
- (f) 2016-2027 On-Peak Blended Market Prices for QF resource
- (g) 2016-2027 Off-Peak Blended Market Prices for QF resource

Tracking Solar Capacity Contribution

36.7%

Exhibit 5
Renewable Avoided Cost Prices for Base Load QF(1)
\$/MWH

Year	Renewable Wind Avoided Resource		Renewable Base Load QF Resource			
	On-Peak (\$/MWh) (a)	Off-Peak (\$/MWh) (b)	Capital Cost Allocated to Capacity (On-Peak Hours) (\$/MWh) (c)	QF Capacity Adder (\$/MWh) (d)	On-Peak \$/MWh (e)	Off-Peak \$/MWh (f)
2016					\$23.43	\$19.86
2017					\$26.30	\$21.68
2018					\$28.22	\$22.97
2019					\$29.44	\$23.80
2020					\$30.99	\$25.14
2021					\$33.03	\$27.14
2022					\$35.96	\$30.03
2023					\$40.26	\$33.69
2024					\$44.43	\$37.30
2025					\$46.61	\$39.32
2026					\$48.41	\$40.90
2027					\$50.57	\$42.74
2028	\$75.90	\$61.86	\$29.85	\$22.27	\$102.26	\$65.95
2029	\$77.43	\$63.21	\$30.48	\$22.74	\$104.35	\$67.39
2030	\$79.29	\$64.42	\$31.15	\$23.24	\$106.80	\$68.69
2031	\$80.89	\$65.90	\$31.84	\$23.75	\$109.00	\$70.26
2032	\$82.60	\$67.56	\$32.54	\$24.27	\$111.33	\$72.02
2033	\$84.29	\$69.18	\$33.26	\$24.81	\$113.66	\$73.74
2034	\$86.09	\$70.82	\$33.98	\$25.35	\$116.10	\$75.48
2035	\$87.62	\$72.79	\$34.73	\$25.91	\$118.29	\$77.55

(c) = (a) + (d)

(d) = (c) * 74.6%

(e) = (a) + (d)

(f) = (b)

Columns
(e) 2016-2027 On-Peak Blended Market Prices for QF resource
(f) 2016-2027 Off-Peak Blended Market Prices for QF resource

(1) The renewable avoided cost price during the deficiency period is increased by the avoided integration charge

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

Year	Renewable Wind Avoided Resource		Wind QF Resource		Wind QF Resource	
	On-Peak (\$/MWh)	Off-Peak (\$/MWh)	Capital Cost Allocated to Capacity (On-Peak Hours) (\$/MWh)	QF Capacity Adder (\$/MWh)	On-Peak \$/MWh	Off-Peak \$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)
				= (c) * 0.0%	= (a) + (d)	= (b)
2016					\$20.31	\$16.74
2017	\$75.90	\$61.86	\$29.85	\$0.00	\$75.90	\$61.86
2018	\$77.43	\$63.21	\$30.48	\$0.00	\$77.43	\$63.21
2019	\$79.29	\$64.42	\$31.15	\$0.00	\$79.29	\$64.42
2020	\$80.89	\$65.90	\$31.84	\$0.00	\$80.89	\$65.90
2021	\$82.60	\$67.56	\$32.54	\$0.00	\$82.60	\$67.56
2022	\$84.29	\$69.18	\$33.26	\$0.00	\$84.29	\$69.18
2023	\$86.09	\$70.82	\$33.98	\$0.00	\$86.09	\$70.82
2024	\$87.62	\$72.79	\$34.73	\$0.00	\$87.62	\$72.79
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						

(1) During the deficiency period, avoided cost prices will be adjusted by adding the difference between the avoided integration costs and Qualifying Facility's integration costs. If the Wind QF resource is in PacifiCorp's Balancing Area Authority (BAA), the adjustment is zero (integration costs cancel each other out).
If Qualifying Facility Wind resource is not in PacifiCorp's BAA, \$3.06/MWh (\$2014) will be added for avoided integration charges.

(2) During the sufficiency period, avoided cost prices is reduced by an integration charge of \$3.06/MWh (\$2014) for a Qualifying Facility wind resource located in PacifiCorp's BAA (in-system).
If Qualifying Facility wind resource is not in PacifiCorp's BAA, the renewable avoided cost price will be increased by the \$3.06/MWh (\$2014) integration charges.

(3) Wind Integration Charge is \$3.06 (2014 \$ per MWh) - 2015 IRP Volume II-Appendix H, Table H.3
Table 11 - Wind Integration Cost

Columns

- (e) On-Peak Blended Market Prices.
- (f) Off-Peak Blended Market Prices.

Exhibit 7

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

Year	Renewable Wind Avoided Resource		Fixed Solar QF Resource		Fixed Solar QF	
	On-Peak (\$/MWh) (a)	Off-Peak (\$/MWh) (b)	Capital Cost Allocated to Capacity (On-Peak Hours) (\$/MWh) (c)	QF Capacity Adder (\$/MWh) (d)	On-Peak \$/MWh (e)	Off-Peak \$/MWh (f)
2016					\$23.43	\$19.86
2017	\$75.90	\$61.86	\$29.85	\$2.03	\$26.30	\$21.68
2018	\$77.43	\$63.21	\$30.48	\$2.07	\$28.22	\$22.97
2019	\$79.29	\$64.42	\$31.15	\$2.12	\$29.44	\$23.80
2020	\$80.89	\$65.90	\$31.84	\$2.17	\$30.99	\$25.14
2021	\$82.60	\$67.56	\$32.54	\$2.21	\$33.03	\$27.14
2022	\$84.29	\$69.18	\$33.26	\$2.26	\$35.96	\$30.03
2023	\$86.09	\$70.82	\$33.98	\$2.31	\$40.26	\$33.69
2024	\$87.62	\$72.79	\$34.73	\$2.36	\$44.43	\$37.30
2025					\$46.61	\$39.32
2026					\$48.41	\$40.90
2027					\$50.57	\$42.74
2028			\$29.85	\$2.03	\$82.02	\$65.95
2029			\$30.48	\$2.07	\$83.68	\$67.39
2030			\$31.15	\$2.12	\$85.68	\$68.69
2031			\$31.84	\$2.17	\$87.42	\$70.26
2032			\$32.54	\$2.21	\$89.27	\$72.02
2033			\$33.26	\$2.26	\$91.11	\$73.74
2034			\$33.98	\$2.31	\$93.06	\$75.48
2035			\$34.73	\$2.36	\$94.74	\$77.55

(d) = (c) * 6.8%
(e) = (a) + (d)
(f) = (b)

Columns

- (e) On-Peak Blended Market Prices for QF resource
- (f) Off-Peak Blended Market Prices for QF resource

(1) The renewable avoided cost price during the deficiency period is increased by the avoided integration charge

Exhibit 8

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

Year	Renewable Wind Avoided Resource		Tracking Solar QF Resource		Tracking Solar QF	
	On-Peak (\$/MWh) (a)	Off-Peak (\$/MWh) (b)	Capital Cost Allocated to Capacity (On-Peak Hours) (\$/MWh) (c)	QF Capacity Adder (\$/MWh) (d)	On-Peak \$/MWh (e)	Off-Peak \$/MWh (f)
2016					\$23.43	\$19.86
2017					\$26.30	\$21.68
2018					\$28.22	\$22.97
2019					\$29.44	\$23.80
2020					\$30.99	\$25.14
2021					\$33.03	\$27.14
2022					\$35.96	\$30.03
2023					\$40.26	\$33.69
2024					\$44.43	\$37.30
2025					\$46.61	\$39.32
2026					\$48.41	\$40.90
2027					\$50.57	\$42.74
2028	\$75.90	\$61.86	\$29.85	\$3.37	\$83.36	\$65.95
2029	\$77.43	\$63.21	\$30.48	\$3.44	\$85.05	\$67.39
2030	\$79.29	\$64.42	\$31.15	\$3.52	\$87.08	\$68.69
2031	\$80.89	\$65.90	\$31.84	\$3.60	\$88.85	\$70.26
2032	\$82.60	\$67.56	\$32.54	\$3.68	\$90.74	\$72.02
2033	\$84.29	\$69.18	\$33.26	\$3.76	\$92.61	\$73.74
2034	\$86.09	\$70.82	\$33.98	\$3.84	\$94.59	\$75.48
2035	\$87.62	\$72.79	\$34.73	\$3.92	\$96.30	\$77.55

=(c) * 11.3%

Columns

- (e) On-Peak Blended Market Prices for QF resource
- (f) Off-Peak Blended Market Prices for QF resource

(1) The renewable avoided cost price during the deficiency period is increased by the avoided integration charge

Exhibit 9
Market Price - Blending Matrix (1)

Period	On-Peak				Off-Peak			
	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2016	9.1%	24.0%	66.8%	100.0%	11.1%	0.4%	88.5%	100.0%
2/1/2016	28.2%	20.1%	51.7%	100.0%	8.1%	69.1%	22.7%	100.0%
3/1/2016	31.9%	5.6%	62.4%	100.0%	12.9%	0.0%	87.1%	100.0%
4/1/2016	27.8%	12.2%	60.0%	100.0%	19.1%	0.8%	80.2%	100.0%
5/1/2016	20.1%	0.0%	79.9%	100.0%	0.8%	0.0%	99.2%	100.0%
6/1/2016	13.9%	0.0%	86.1%	100.0%	9.3%	0.0%	90.7%	100.0%
7/1/2016	12.2%	77.2%	10.6%	100.0%	23.2%	6.3%	70.6%	100.0%
8/1/2016	8.1%	86.8%	5.0%	100.0%	11.1%	62.3%	26.7%	100.0%
9/1/2016	1.0%	97.4%	1.6%	100.0%	12.3%	18.1%	69.6%	100.0%
10/1/2016	9.6%	72.0%	18.4%	100.0%	14.5%	55.5%	30.0%	100.0%
11/1/2016	13.8%	79.6%	6.5%	100.0%	39.8%	16.0%	44.2%	100.0%
12/1/2016	26.4%	56.5%	17.1%	100.0%	19.1%	19.6%	61.3%	100.0%
1/1/2017	73.3%	9.4%	17.3%	100.0%	23.5%	13.0%	63.5%	100.0%
2/1/2017	52.4%	10.1%	37.5%	100.0%	19.8%	20.5%	59.7%	100.0%
3/1/2017	43.4%	9.7%	46.9%	100.0%	22.8%	14.2%	63.1%	100.0%
4/1/2017	36.1%	3.2%	60.8%	100.0%	21.1%	0.7%	78.2%	100.0%
5/1/2017	22.7%	0.7%	76.5%	100.0%	24.8%	0.0%	75.2%	100.0%
6/1/2017	32.4%	1.5%	66.1%	100.0%	37.4%	3.1%	59.5%	100.0%
7/1/2017	26.6%	18.1%	55.3%	100.0%	44.4%	11.2%	44.4%	100.0%
8/1/2017	22.4%	51.5%	26.1%	100.0%	21.8%	27.4%	50.8%	100.0%
9/1/2017	10.7%	64.7%	24.6%	100.0%	17.7%	18.5%	63.8%	100.0%
10/1/2017	26.6%	26.5%	46.9%	100.0%	9.5%	32.4%	58.1%	100.0%
11/1/2017	60.5%	11.4%	28.2%	100.0%	28.2%	0.6%	71.2%	100.0%
12/1/2017	63.5%	7.9%	28.7%	100.0%	27.6%	5.4%	66.9%	100.0%
1/1/2018	84.1%	6.9%	9.0%	100.0%	18.7%	6.7%	74.6%	100.0%
2/1/2018	61.5%	8.9%	29.7%	100.0%	18.9%	14.0%	67.1%	100.0%
3/1/2018	28.6%	14.6%	56.7%	100.0%	24.6%	27.6%	47.9%	100.0%
4/1/2018	54.5%	11.2%	34.3%	100.0%	59.5%	7.0%	33.5%	100.0%
5/1/2018	28.8%	0.0%	71.2%	100.0%	25.8%	0.0%	74.2%	100.0%
6/1/2018	13.6%	0.0%	86.4%	100.0%	14.2%	0.0%	85.8%	100.0%
7/1/2018	29.1%	38.7%	32.2%	100.0%	39.9%	7.3%	52.7%	100.0%
8/1/2018	12.2%	63.4%	24.4%	100.0%	16.6%	58.4%	25.1%	100.0%
9/1/2018	13.6%	65.0%	21.4%	100.0%	33.0%	6.9%	60.1%	100.0%
10/1/2018	21.2%	15.7%	63.1%	100.0%	27.1%	30.1%	42.8%	100.0%
11/1/2018	59.6%	9.6%	30.9%	100.0%	15.5%	2.2%	82.2%	100.0%
12/1/2018	69.9%	7.0%	23.1%	100.0%	22.7%	4.4%	72.9%	100.0%
1/1/2019	100.0%	0.0%	0.0%	100.0%	4.5%	13.2%	82.3%	100.0%
2/1/2019	73.2%	6.8%	20.0%	100.0%	16.4%	15.9%	67.7%	100.0%
3/1/2019	44.4%	7.6%	48.0%	100.0%	14.5%	23.8%	61.7%	100.0%
4/1/2019	55.5%	11.9%	32.6%	100.0%	58.8%	9.0%	32.1%	100.0%
5/1/2019	21.6%	1.1%	77.3%	100.0%	20.8%	6.6%	72.6%	100.0%
6/1/2019	19.5%	0.0%	80.5%	100.0%	27.0%	0.0%	73.0%	100.0%
7/1/2019	19.8%	42.4%	37.8%	100.0%	42.6%	8.4%	49.0%	100.0%
8/1/2019	14.8%	59.9%	25.3%	100.0%	30.9%	40.4%	28.6%	100.0%
9/1/2019	5.1%	77.9%	17.0%	100.0%	38.0%	13.8%	48.3%	100.0%
10/1/2019	19.7%	16.0%	64.3%	100.0%	31.3%	21.7%	47.0%	100.0%
11/1/2019	54.8%	6.0%	39.1%	100.0%	17.1%	2.0%	81.0%	100.0%
12/1/2019	26.7%	1.6%	71.7%	100.0%	15.9%	5.6%	78.5%	100.0%
1/1/2020	81.7%	1.1%	17.3%	100.0%	12.7%	0.2%	87.1%	100.0%
2/1/2020	62.6%	5.8%	31.5%	100.0%	15.3%	3.9%	80.8%	100.0%
3/1/2020	39.4%	6.3%	54.3%	100.0%	19.7%	12.2%	68.1%	100.0%
4/1/2020	60.2%	11.1%	28.6%	100.0%	56.3%	3.0%	40.7%	100.0%
5/1/2020	24.4%	0.4%	75.2%	100.0%	24.6%	0.3%	75.1%	100.0%
6/1/2020	27.2%	0.0%	72.8%	100.0%	13.7%	0.0%	86.3%	100.0%
7/1/2020	15.4%	39.1%	45.4%	100.0%	25.1%	9.3%	65.6%	100.0%
8/1/2020	20.8%	48.5%	30.7%	100.0%	22.7%	37.0%	40.3%	100.0%
9/1/2020	12.3%	63.4%	24.4%	100.0%	22.3%	4.5%	73.2%	100.0%
10/1/2020	28.7%	13.7%	57.7%	100.0%	11.9%	23.1%	65.0%	100.0%
11/1/2020	59.4%	6.4%	34.2%	100.0%	9.9%	2.4%	87.7%	100.0%
12/1/2020	63.7%	9.4%	26.9%	100.0%	19.9%	3.0%	77.1%	100.0%

Exhibit 9
Market Price - Blending Matrix (1)

Period	On-Peak				Off-Peak			
	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2021	81.2%	4.1%	14.7%	100.0%	14.0%	8.0%	78.0%	100.0%
2/1/2021	62.0%	5.9%	32.1%	100.0%	11.6%	8.8%	79.6%	100.0%
3/1/2021	50.8%	5.2%	44.0%	100.0%	14.5%	18.8%	66.7%	100.0%
4/1/2021	70.7%	6.3%	23.0%	100.0%	62.0%	1.8%	36.2%	100.0%
5/1/2021	28.2%	0.0%	71.8%	100.0%	17.3%	0.9%	81.8%	100.0%
6/1/2021	16.6%	0.0%	83.4%	100.0%	15.5%	0.0%	84.5%	100.0%
7/1/2021	25.5%	6.1%	68.4%	100.0%	19.5%	8.8%	71.8%	100.0%
8/1/2021	18.9%	48.8%	32.2%	100.0%	7.6%	39.5%	52.9%	100.0%
9/1/2021	15.3%	60.5%	24.2%	100.0%	13.7%	8.0%	78.3%	100.0%
10/1/2021	22.1%	13.1%	64.8%	100.0%	11.1%	25.8%	63.1%	100.0%
11/1/2021	59.2%	13.6%	27.1%	100.0%	12.9%	0.4%	86.7%	100.0%
12/1/2021	64.1%	5.0%	30.9%	100.0%	24.4%	1.6%	74.0%	100.0%
1/1/2022	82.6%	0.1%	17.4%	100.0%	13.7%	8.4%	77.9%	100.0%
2/1/2022	67.8%	2.8%	29.4%	100.0%	10.3%	16.9%	72.9%	100.0%
3/1/2022	36.1%	10.5%	53.4%	100.0%	21.0%	14.9%	64.1%	100.0%
4/1/2022	47.5%	10.1%	42.4%	100.0%	47.4%	0.0%	52.6%	100.0%
5/1/2022	27.3%	0.0%	72.7%	100.0%	20.8%	3.8%	75.4%	100.0%
6/1/2022	21.8%	2.1%	76.1%	100.0%	21.4%	6.2%	72.4%	100.0%
7/1/2022	29.3%	26.1%	44.6%	100.0%	20.6%	9.7%	69.7%	100.0%
8/1/2022	19.3%	50.2%	30.5%	100.0%	25.1%	45.4%	29.4%	100.0%
9/1/2022	7.1%	50.5%	42.3%	100.0%	19.5%	3.1%	77.4%	100.0%
10/1/2022	20.6%	16.1%	63.2%	100.0%	17.2%	34.2%	48.7%	100.0%
11/1/2022	39.7%	9.0%	51.3%	100.0%	33.4%	9.4%	57.2%	100.0%
12/1/2022	59.9%	10.1%	30.0%	100.0%	25.6%	9.7%	64.6%	100.0%
1/1/2023	83.1%	3.3%	13.6%	100.0%	21.4%	9.1%	69.5%	100.0%
2/1/2023	48.1%	13.8%	38.1%	100.0%	25.4%	22.0%	52.7%	100.0%
3/1/2023	39.8%	9.3%	50.9%	100.0%	23.3%	24.9%	51.8%	100.0%
4/1/2023	48.1%	6.5%	45.4%	100.0%	25.0%	7.8%	67.3%	100.0%
5/1/2023	15.3%	0.3%	84.4%	100.0%	35.2%	6.0%	58.8%	100.0%
6/1/2023	24.9%	9.3%	65.7%	100.0%	53.3%	12.1%	34.5%	100.0%
7/1/2023	30.4%	28.0%	41.6%	100.0%	30.4%	7.5%	62.2%	100.0%
8/1/2023	17.5%	51.3%	31.2%	100.0%	29.8%	43.7%	26.4%	100.0%
9/1/2023	5.9%	37.9%	56.2%	100.0%	25.6%	11.4%	63.0%	100.0%
10/1/2023	20.9%	15.0%	64.1%	100.0%	19.4%	30.1%	50.5%	100.0%
11/1/2023	41.0%	10.4%	48.6%	100.0%	31.6%	10.3%	58.2%	100.0%
12/1/2023	35.4%	7.4%	57.3%	100.0%	22.1%	7.6%	70.3%	100.0%
1/1/2024	60.0%	14.1%	26.0%	100.0%	30.1%	10.9%	59.0%	100.0%
2/1/2024	35.2%	18.4%	46.4%	100.0%	28.6%	19.3%	52.1%	100.0%
3/1/2024	44.9%	12.2%	42.9%	100.0%	38.3%	26.6%	35.2%	100.0%
4/1/2024	50.8%	16.5%	32.8%	100.0%	28.2%	14.7%	57.1%	100.0%
5/1/2024	14.1%	0.0%	85.9%	100.0%	24.4%	5.5%	70.1%	100.0%
6/1/2024	19.5%	5.0%	75.6%	100.0%	32.4%	8.3%	59.3%	100.0%
7/1/2024	20.3%	45.1%	34.5%	100.0%	35.1%	16.8%	48.2%	100.0%
8/1/2024	21.2%	49.5%	29.3%	100.0%	25.1%	47.4%	27.5%	100.0%
9/1/2024	5.2%	47.9%	46.9%	100.0%	25.7%	11.8%	62.5%	100.0%
10/1/2024	24.7%	17.2%	58.1%	100.0%	20.1%	31.2%	48.7%	100.0%
11/1/2024	36.6%	10.3%	53.0%	100.0%	33.6%	23.3%	43.1%	100.0%
12/1/2024	59.3%	19.2%	21.5%	100.0%	6.9%	25.3%	67.8%	100.0%
1/1/2025	64.2%	8.6%	27.2%	100.0%	59.5%	0.5%	40.0%	100.0%
2/1/2025	55.1%	16.9%	28.0%	100.0%	31.2%	14.2%	54.6%	100.0%
3/1/2025	41.1%	19.2%	39.7%	100.0%	33.7%	32.4%	33.9%	100.0%
4/1/2025	54.0%	12.0%	34.0%	100.0%	23.3%	12.3%	64.3%	100.0%
5/1/2025	20.5%	0.0%	79.5%	100.0%	25.5%	5.1%	69.5%	100.0%
6/1/2025	24.0%	4.1%	71.9%	100.0%	29.9%	14.7%	55.4%	100.0%
7/1/2025	16.7%	56.5%	26.8%	100.0%	39.4%	7.5%	53.0%	100.0%
8/1/2025	19.1%	64.1%	16.8%	100.0%	25.8%	48.8%	25.4%	100.0%
9/1/2025	4.6%	78.0%	17.4%	100.0%	25.8%	12.9%	61.2%	100.0%
10/1/2025	30.6%	19.2%	50.1%	100.0%	28.8%	34.1%	37.0%	100.0%
11/1/2025	38.8%	14.3%	46.9%	100.0%	32.2%	30.2%	37.6%	100.0%
12/1/2025	51.2%	13.7%	35.2%	100.0%	20.3%	19.0%	60.8%	100.0%

Exhibit 9
Market Price - Blending Matrix (1)

Period	On-Peak				Off-Peak			
	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2026	51.3%	8.4%	40.3%	100.0%	26.5%	24.5%	49.0%	100.0%
2/1/2026	38.5%	14.4%	47.2%	100.0%	27.4%	13.5%	59.1%	100.0%
3/1/2026	38.7%	24.3%	37.0%	100.0%	39.4%	26.6%	34.0%	100.0%
4/1/2026	53.3%	14.7%	32.0%	100.0%	32.8%	20.2%	47.1%	100.0%
5/1/2026	30.3%	1.6%	68.1%	100.0%	33.4%	5.9%	60.7%	100.0%
6/1/2026	24.2%	7.4%	68.4%	100.0%	33.1%	14.8%	52.1%	100.0%
7/1/2026	18.4%	56.4%	25.2%	100.0%	42.2%	8.1%	49.7%	100.0%
8/1/2026	20.2%	60.3%	19.5%	100.0%	21.7%	55.1%	23.2%	100.0%
9/1/2026	8.1%	61.4%	30.4%	100.0%	17.5%	17.6%	64.9%	100.0%
10/1/2026	23.1%	23.8%	53.1%	100.0%	26.0%	35.9%	38.2%	100.0%
11/1/2026	37.2%	9.5%	53.3%	100.0%	40.7%	29.1%	30.1%	100.0%
12/1/2026	48.6%	13.8%	37.6%	100.0%	33.6%	17.3%	49.2%	100.0%
1/1/2027	49.2%	10.2%	40.6%	100.0%	26.3%	32.2%	41.5%	100.0%
2/1/2027	40.9%	15.8%	43.3%	100.0%	18.8%	31.2%	50.0%	100.0%
3/1/2027	46.3%	20.9%	32.8%	100.0%	33.7%	34.2%	32.1%	100.0%
4/1/2027	54.7%	16.1%	29.3%	100.0%	36.1%	17.4%	46.4%	100.0%
5/1/2027	25.1%	0.8%	74.1%	100.0%	26.3%	7.4%	66.3%	100.0%
6/1/2027	28.9%	9.5%	61.6%	100.0%	42.1%	15.9%	42.0%	100.0%
7/1/2027	19.1%	57.8%	23.2%	100.0%	38.6%	12.0%	49.4%	100.0%
8/1/2027	17.5%	62.0%	20.5%	100.0%	22.4%	50.8%	26.8%	100.0%
9/1/2027	10.1%	60.8%	29.1%	100.0%	24.1%	15.4%	60.5%	100.0%
10/1/2027	28.9%	21.4%	49.7%	100.0%	19.8%	41.3%	38.9%	100.0%
11/1/2027	39.1%	14.8%	46.1%	100.0%	27.7%	32.1%	40.2%	100.0%
12/1/2027	57.2%	13.5%	29.3%	100.0%	34.7%	21.2%	44.2%	100.0%
1/1/2028	32.7%	11.7%	55.6%	100.0%	30.4%	26.0%	43.7%	100.0%
2/1/2028	27.6%	10.5%	61.9%	100.0%	32.2%	21.8%	46.0%	100.0%
3/1/2028	29.6%	18.9%	51.5%	100.0%	42.4%	31.0%	26.6%	100.0%
4/1/2028	45.2%	15.0%	39.8%	100.0%	26.4%	9.7%	63.9%	100.0%
5/1/2028	24.0%	3.5%	72.5%	100.0%	29.5%	5.0%	65.5%	100.0%
6/1/2028	23.8%	10.9%	65.3%	100.0%	32.1%	9.7%	58.2%	100.0%
7/1/2028	19.9%	64.1%	16.0%	100.0%	31.6%	15.8%	52.6%	100.0%
8/1/2028	16.6%	69.3%	14.1%	100.0%	24.1%	59.0%	16.9%	100.0%
9/1/2028	7.7%	58.9%	33.4%	100.0%	25.4%	14.2%	60.4%	100.0%
10/1/2028	28.5%	10.9%	60.6%	100.0%	20.5%	29.1%	50.3%	100.0%
11/1/2028	29.4%	8.9%	61.7%	100.0%	33.8%	20.0%	46.1%	100.0%
12/1/2028	27.5%	4.6%	67.9%	100.0%	25.4%	20.6%	54.0%	100.0%
1/1/2029	29.8%	7.0%	63.3%	100.0%	34.0%	19.0%	47.0%	100.0%
2/1/2029	30.7%	5.5%	63.8%	100.0%	28.1%	16.4%	55.5%	100.0%
3/1/2029	35.1%	12.0%	52.9%	100.0%	36.7%	35.9%	27.4%	100.0%
4/1/2029	45.2%	12.2%	42.6%	100.0%	28.8%	17.8%	53.5%	100.0%
5/1/2029	30.2%	1.5%	68.3%	100.0%	38.2%	6.4%	55.5%	100.0%
6/1/2029	26.9%	8.4%	64.7%	100.0%	22.2%	11.7%	66.2%	100.0%
7/1/2029	17.0%	68.2%	14.8%	100.0%	30.8%	14.6%	54.6%	100.0%
8/1/2029	20.0%	66.5%	13.5%	100.0%	25.2%	57.4%	17.4%	100.0%
9/1/2029	4.8%	63.1%	32.2%	100.0%	24.0%	0.0%	76.0%	100.0%
10/1/2029	22.6%	19.5%	57.9%	100.0%	25.3%	28.1%	46.5%	100.0%
11/1/2029	29.1%	11.3%	59.5%	100.0%	30.8%	26.6%	42.7%	100.0%
12/1/2029	30.7%	7.3%	62.0%	100.0%	24.3%	21.6%	54.1%	100.0%
1/1/2030	26.7%	9.2%	64.2%	100.0%	30.6%	29.1%	40.4%	100.0%
2/1/2030	23.0%	4.1%	72.9%	100.0%	37.5%	21.4%	41.0%	100.0%
3/1/2030	35.1%	14.3%	50.6%	100.0%	36.2%	32.1%	31.7%	100.0%
4/1/2030	43.3%	13.1%	43.6%	100.0%	37.9%	10.5%	51.6%	100.0%
5/1/2030	28.3%	0.0%	71.7%	100.0%	30.2%	3.0%	66.7%	100.0%
6/1/2030	31.9%	9.7%	58.4%	100.0%	15.4%	4.1%	80.5%	100.0%
7/1/2030	23.4%	57.6%	19.0%	100.0%	22.6%	13.0%	64.5%	100.0%
8/1/2030	13.4%	69.7%	16.8%	100.0%	36.8%	21.0%	42.2%	100.0%
9/1/2030	7.3%	62.5%	30.2%	100.0%	23.2%	13.6%	63.1%	100.0%
10/1/2030	24.8%	16.3%	58.9%	100.0%	26.3%	33.4%	40.3%	100.0%
11/1/2030	29.1%	10.9%	60.0%	100.0%	36.0%	31.0%	33.1%	100.0%
12/1/2030	37.8%	9.3%	52.9%	100.0%	31.9%	22.9%	45.2%	100.0%

Exhibit 9
Market Price - Blending Matrix (1)

Period	On-Peak				Off-Peak			
	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2031	22.4%	6.3%	71.3%	100.0%	37.6%	21.2%	41.2%	100.0%
2/1/2031	24.6%	9.6%	65.8%	100.0%	28.7%	17.5%	53.8%	100.0%
3/1/2031	41.1%	16.2%	42.7%	100.0%	44.3%	25.1%	30.6%	100.0%
4/1/2031	44.8%	11.0%	44.1%	100.0%	35.0%	26.8%	38.2%	100.0%
5/1/2031	24.0%	4.6%	71.4%	100.0%	22.7%	5.0%	72.3%	100.0%
6/1/2031	22.0%	7.3%	70.8%	100.0%	18.5%	11.1%	70.4%	100.0%
7/1/2031	21.5%	71.9%	6.6%	100.0%	37.9%	16.3%	45.8%	100.0%
8/1/2031	16.4%	79.8%	3.7%	100.0%	18.2%	64.7%	17.1%	100.0%
9/1/2031	10.8%	67.1%	22.1%	100.0%	37.1%	3.1%	59.8%	100.0%
10/1/2031	23.9%	13.7%	62.5%	100.0%	26.4%	39.0%	34.5%	100.0%
11/1/2031	34.6%	7.7%	57.7%	100.0%	42.0%	15.2%	42.8%	100.0%
12/1/2031	20.5%	4.4%	75.1%	100.0%	40.5%	12.6%	46.9%	100.0%
1/1/2032	28.9%	6.1%	65.0%	100.0%	37.3%	24.3%	38.4%	100.0%
2/1/2032	29.2%	7.6%	63.2%	100.0%	34.5%	19.5%	46.0%	100.0%
3/1/2032	40.1%	13.0%	46.9%	100.0%	40.8%	27.9%	31.3%	100.0%
4/1/2032	44.4%	10.4%	45.2%	100.0%	42.8%	20.3%	36.9%	100.0%
5/1/2032	22.4%	5.0%	72.6%	100.0%	20.0%	5.0%	75.1%	100.0%
6/1/2032	23.2%	11.5%	65.3%	100.0%	14.8%	11.9%	73.4%	100.0%
7/1/2032	24.1%	67.8%	8.2%	100.0%	35.3%	17.0%	47.7%	100.0%
8/1/2032	21.6%	70.6%	7.8%	100.0%	23.0%	60.8%	16.1%	100.0%
9/1/2032	13.1%	61.2%	25.7%	100.0%	31.2%	7.1%	61.7%	100.0%
10/1/2032	25.4%	13.9%	60.7%	100.0%	24.0%	42.3%	33.7%	100.0%
11/1/2032	33.6%	9.5%	56.9%	100.0%	41.5%	23.1%	35.3%	100.0%
12/1/2032	25.7%	6.7%	67.6%	100.0%	41.4%	15.1%	43.5%	100.0%
1/1/2033	35.2%	4.3%	60.5%	100.0%	42.9%	13.0%	44.1%	100.0%
2/1/2033	15.4%	13.2%	71.4%	100.0%	47.2%	4.1%	48.7%	100.0%
3/1/2033	40.0%	17.1%	42.9%	100.0%	47.5%	21.2%	31.3%	100.0%
4/1/2033	46.8%	11.1%	42.1%	100.0%	41.4%	18.7%	39.9%	100.0%
5/1/2033	28.8%	0.6%	70.6%	100.0%	18.3%	8.7%	73.0%	100.0%
6/1/2033	24.1%	9.2%	66.7%	100.0%	14.0%	13.1%	73.0%	100.0%
7/1/2033	14.8%	70.2%	15.0%	100.0%	30.7%	8.9%	60.4%	100.0%
8/1/2033	17.3%	77.9%	4.8%	100.0%	28.7%	56.2%	15.1%	100.0%
9/1/2033	11.1%	63.1%	25.8%	100.0%	30.4%	6.8%	62.8%	100.0%
10/1/2033	25.8%	13.0%	61.3%	100.0%	27.2%	41.7%	31.1%	100.0%
11/1/2033	28.8%	7.8%	63.4%	100.0%	43.5%	13.1%	43.5%	100.0%
12/1/2033	24.2%	5.8%	70.0%	100.0%	35.2%	13.6%	51.3%	100.0%
1/1/2034	23.2%	4.3%	72.5%	100.0%	31.1%	18.2%	50.7%	100.0%
2/1/2034	26.3%	5.2%	68.5%	100.0%	38.6%	11.1%	50.3%	100.0%
3/1/2034	40.0%	17.0%	43.0%	100.0%	39.7%	28.3%	32.0%	100.0%
4/1/2034	46.0%	9.6%	44.4%	100.0%	43.5%	14.1%	42.4%	100.0%
5/1/2034	30.5%	4.8%	64.7%	100.0%	23.1%	3.2%	73.7%	100.0%
6/1/2034	27.1%	7.4%	65.4%	100.0%	19.9%	10.5%	69.6%	100.0%
7/1/2034	15.2%	76.3%	8.5%	100.0%	33.4%	9.7%	56.8%	100.0%
8/1/2034	17.6%	74.8%	7.6%	100.0%	21.1%	55.1%	23.8%	100.0%
9/1/2034	11.5%	62.3%	26.2%	100.0%	26.0%	5.0%	69.0%	100.0%
10/1/2034	32.1%	14.1%	53.8%	100.0%	28.7%	25.2%	46.1%	100.0%
11/1/2034	28.7%	5.9%	65.4%	100.0%	34.7%	30.1%	35.2%	100.0%
12/1/2034	24.6%	4.2%	71.2%	100.0%	35.7%	13.6%	50.7%	100.0%
1/1/2035	22.0%	5.1%	72.9%	100.0%	26.2%	15.9%	57.9%	100.0%
2/1/2035	14.2%	6.3%	79.5%	100.0%	34.2%	16.8%	49.0%	100.0%
3/1/2035	36.7%	17.8%	45.5%	100.0%	36.5%	36.0%	27.6%	100.0%
4/1/2035	44.8%	11.2%	44.0%	100.0%	49.4%	10.9%	39.7%	100.0%
5/1/2035	24.6%	1.9%	73.4%	100.0%	23.9%	6.1%	70.0%	100.0%
6/1/2035	29.0%	7.9%	63.1%	100.0%	9.4%	7.9%	82.7%	100.0%
7/1/2035	18.3%	65.2%	16.5%	100.0%	26.7%	8.8%	64.6%	100.0%
8/1/2035	21.1%	69.6%	9.3%	100.0%	32.6%	42.1%	25.3%	100.0%
9/1/2035	15.0%	68.5%	16.5%	100.0%	24.4%	7.2%	68.4%	100.0%
10/1/2035	25.0%	17.1%	57.9%	100.0%	39.0%	24.5%	36.5%	100.0%
11/1/2035	31.4%	9.3%	59.3%	100.0%	38.9%	26.0%	35.2%	100.0%
12/1/2035	27.6%	2.5%	69.9%	100.0%	32.6%	17.2%	50.2%	100.0%

(1) Blending weights are calculated using system balancing purchases and sales from GRID run using March 2016 Official Forward Market Price Curve

Table 1
2015 IRP Preferred Portfolio
Excerpt from 2015 IRP Table 8.7

Resource	Capacity (MW)													
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Expansion Resources														
CCCT - DJohns - F 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423
CCCT - Utah-N - F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 2, ID	4	4	5	5	5	4	4	4	5	5	5	5	5	5
DSM, Class 2, UT	69	78	84	86	92	81	84	90	91	93	75	76	80	80
DSM, Class 2, WY	6	8	10	12	14	12	13	14	15	16	13	13	14	15
DSM, Class 2 Total	79	90	99	102	111	97	101	108	110	114	92	94	99	99
FOT Mona Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	161
Expansion Resources														
Oregon Solar Capacity Standard	-	7	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	10.6	-	-	10.6	-	-
DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	5.0	-	-	-	-	-	-
DSM, Class 1 Total	-	-	-	-	-	-	-	5.0	10.6	-	-	10.6	-	-
DSM, Class 2, CA	1	2	2	2	2	1	1	2	2	2	1	1	1	1
DSM, Class 2, OR	44	39	36	33	29	27	25	25	23	23	21	22	22	22
DSM, Class 2, WA	8	9	10	10	11	9	10	10	11	11	9	9	9	9
DSM, Class 2 Total	54	49	47	44	42	38	36	36	36	35	31	32	32	32
FOT COB Q3	-	62	29	-	60	104	-	-	-	-	-	-	-	268
FOT MidColumbia Q3 - 2	227	375	375	370	375	375	269	291	261	254	271	292	335	375
Total Annual Additions	860	1,084	1,050	1,016	1,088	1,113	906	941	917	903	893	928	965	1,859

The 2015 IRP was prepared using a 13% planning reserve margin. See 2015 IRP, page 81.

Table 2
Avoided Costs (\$/MWh)
Energy Prices 2016 through 2035

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

On-Peak (HLH Market Purchase)

2016						20.04	21.37	24.22	22.76	22.61	24.68	28.30
2017	28.10	27.24	24.24	20.50	21.04	22.62	29.23	29.77	26.71	26.67	28.41	31.07
2018	29.79	28.94	26.33	23.17	21.95	24.24	29.83	31.81	29.60	29.50	30.42	33.03
2019	32.09	30.86	27.99	25.24	23.50	25.55	31.43	33.26	30.83	30.25	30.85	31.47
2020	33.12	32.06	29.29	26.86	24.92	26.79	33.10	34.79	32.24	31.61	32.34	34.74
2021	34.57	33.59	31.17	28.73	26.70	28.77	37.09	36.40	33.89	33.67	34.74	36.97
2022	36.62	35.72	32.79	29.57	30.74	33.74	38.16	39.81	37.98	36.73	38.60	41.04
2023	41.99	41.58	37.56	34.65	35.30	38.47	40.84	43.22	41.89	39.85	43.27	44.47
2024	46.83	47.64	42.08	39.19	37.38	40.61	43.58	47.29	46.90	45.08	48.36	48.20
2025	49.39	50.84	44.82	43.01	38.83	43.19	45.48	50.58	50.20	45.79	46.97	50.20
2026	51.16	52.51	46.47	44.71	41.03	45.02	47.65	52.40	51.63	46.98	49.47	51.89
2027	52.90	54.45	48.57	45.76	42.20	46.53	49.09	54.20	53.79	50.20	53.48	55.69
2028	52.91	54.14	48.71	45.98	44.18	48.51	50.10	55.47	54.99	51.91	54.45	56.27
2029	55.93	57.02	51.69	48.80	45.15	48.09	50.50	57.34	56.00	51.53	54.14	56.32
2030	55.81	56.45	51.57	48.82	46.01	49.74	53.45	59.38	59.36	54.21	57.27	59.11
2031	57.61	58.12	52.52	49.88	46.99	51.83	54.56	60.88	61.55	54.98	57.32	59.71
2032	59.65	59.87	54.23	51.90	48.17	52.55	54.67	62.28	61.34	55.70	59.06	60.76
2033	60.61	61.29	55.04	52.92	49.52	54.07	56.52	63.63	62.30	57.32	61.14	62.09
2034	63.40	63.28	56.89	54.67	51.39	56.58	58.41	65.97	63.40	58.38	61.64	62.94
2035	62.61	62.85	57.48	55.52	53.11	56.30	60.06	67.28	64.71	59.12	61.39	64.05

Off-Peak (LLH Market Purchase)

2016						15.51	17.44	19.31	20.00	20.58	22.66	23.48
2017	24.39	23.42	21.01	18.47	16.22	16.23	20.21	23.40	24.19	22.79	24.25	25.63
2018	26.43	25.46	23.81	19.16	16.38	17.63	20.62	22.26	25.34	25.25	26.03	27.25
2019	27.27	26.57	25.05	19.74	16.35	17.41	21.16	23.77	25.98	26.78	27.20	28.34
2020	28.79	28.02	26.66	19.89	17.54	18.91	23.54	25.76	27.45	27.80	28.05	29.31
2021	29.51	28.68	27.18	23.82	21.40	22.45	26.21	28.54	29.61	28.82	29.08	30.44
2022	31.30	30.33	29.01	25.12	25.90	26.77	30.09	30.85	32.61	31.23	32.85	34.37
2023	35.73	35.42	32.92	30.35	29.45	29.46	33.81	33.13	35.56	34.00	36.26	38.24
2024	39.85	40.66	36.56	35.82	32.08	33.29	35.61	36.36	39.23	37.68	39.90	40.63
2025	42.17	43.70	39.26	39.08	33.88	34.72	38.15	39.61	41.32	38.00	39.40	42.53
2026	43.20	45.40	41.07	40.06	35.54	36.16	40.60	41.17	42.95	39.47	41.11	44.03
2027	44.67	46.47	42.26	41.25	36.74	37.03	42.19	42.93	45.36	42.23	44.64	47.12
2028	44.74	46.81	41.36	42.23	38.27	39.94	44.01	43.55	46.64	43.89	45.52	48.47
2029	47.22	49.59	43.92	43.76	38.93	40.71	44.59	44.70	47.67	43.49	45.31	48.56
2030	46.50	47.98	44.94	44.70	40.72	43.76	46.26	48.08	49.33	45.59	47.48	50.66
2031	47.86	50.26	46.33	44.98	42.15	44.19	46.81	47.99	49.36	46.41	48.13	50.71
2032	50.13	51.75	48.18	46.81	43.69	45.09	47.23	48.43	49.94	47.35	48.73	51.86
2033	51.84	52.66	49.42	48.18	44.52	46.30	49.84	49.80	51.33	48.83	50.61	54.14
2034	54.18	55.20	51.06	49.82	46.60	48.08	51.34	51.65	52.14	50.15	50.30	55.18
2035	54.58	55.22	51.55	50.76	47.87	49.18	53.14	53.65	54.15	50.27	51.35	56.12

Table 2
Avoided Costs (\$/MWh)
Energy Prices 2016 through 2035

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Combined												
2016						18.09	19.68	22.11	21.57	21.74	23.81	26.23
2017	26.50	25.60	22.85	19.63	18.97	19.87	25.35	27.03	25.63	25.00	26.62	28.73
2018	28.35	27.44	25.25	21.44	19.55	21.40	25.87	27.70	27.77	27.67	28.53	30.54
2019	30.02	29.02	26.73	22.87	20.42	22.05	27.01	29.18	28.74	28.76	29.28	30.12
2020	31.26	30.32	28.16	23.86	21.75	23.40	28.99	30.91	30.18	29.97	30.50	32.41
2021	32.39	31.48	29.45	26.62	24.42	26.05	32.41	33.02	32.05	31.58	32.31	34.16
2022	34.34	33.40	31.16	27.66	28.66	30.74	34.69	35.96	35.67	34.37	36.12	38.17
2023	39.30	38.93	35.56	32.80	32.78	34.60	37.82	38.88	39.17	37.33	40.26	41.79
2024	43.83	44.64	39.70	37.74	35.10	37.46	40.15	42.59	43.60	41.90	44.72	44.95
2025	46.28	47.77	42.43	41.32	36.70	39.55	42.33	45.86	46.38	42.44	43.71	46.90
2026	47.74	49.45	44.15	42.71	38.67	41.21	44.62	47.57	47.90	43.75	45.87	48.51
2027	49.36	51.02	45.85	43.82	39.85	42.45	46.13	49.36	50.16	46.77	49.68	52.00
2028	49.40	50.99	45.55	44.36	41.64	44.83	47.48	50.35	51.40	48.46	50.61	52.92
2029	52.18	53.83	48.35	46.63	42.48	44.92	47.96	51.91	52.42	48.07	50.34	52.99
2030	51.81	52.81	48.72	47.05	43.73	47.17	50.36	54.52	55.05	50.51	53.06	55.48
2031	53.42	54.74	49.86	47.77	44.91	48.54	51.23	55.34	56.31	51.29	53.37	55.84
2032	55.56	56.38	51.63	49.71	46.24	49.34	51.47	56.33	56.44	52.11	54.62	56.93
2033	56.84	57.58	52.62	50.88	47.37	50.73	53.65	57.68	57.58	53.67	56.61	58.67
2034	59.43	59.80	54.38	52.58	49.33	52.93	55.37	59.81	58.56	54.84	56.76	59.60
2035	59.16	59.57	54.93	53.47	50.85	53.24	57.08	61.42	60.17	55.32	57.07	60.64

Annual Average

	On-Peak	Off-Peak	Combined
2016	\$23.43	\$19.86	\$21.89
2017	\$26.30	\$21.68	\$24.32
2018	\$28.22	\$22.97	\$25.96
2019	\$29.44	\$23.80	\$27.02
2020	\$30.99	\$25.14	\$28.48
2021	\$33.03	\$27.14	\$30.50
2022	\$35.96	\$30.03	\$33.41
2023	\$40.26	\$33.69	\$37.44
2024	\$44.43	\$37.30	\$41.37
2025	\$46.61	\$39.32	\$43.47
2026	\$48.41	\$40.90	\$45.18
2027	\$50.57	\$42.74	\$47.20
2028	\$51.47	\$43.79	\$48.16
2029	\$52.71	\$44.87	\$49.34
2030	\$54.27	\$46.33	\$50.85
2031	\$55.50	\$47.10	\$51.88
2032	\$56.68	\$48.27	\$53.06
2033	\$58.04	\$49.79	\$54.49
2034	\$59.74	\$51.31	\$56.12
2035	\$60.37	\$52.32	\$56.91

Source Official Market Price Forecast dated March 2016
Blending weights which are used to calculate blended market prices are based on system balancing purchases and sales from GRID run using March 2016 Official Forward Market Price Curve

Table 3
Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs	Simple Cycle CT Fixed Costs	Capitalized Energy Costs	Capitalized Energy Costs 72.1% CF
	(\$/kW-yr)	(\$/kW-yr)	(\$/kW-yr)	(\$/MWh)
	(a)	(b)	(c) (a) - (b)	(d) (c)/(8.760 x 72.1%)
2028	\$149.06	\$162.83	\$0.00	\$0.00
2029	\$152.18	\$166.26	\$0.00	\$0.00
2030	\$155.56	\$169.92	\$0.00	\$0.00
2031	\$158.99	\$173.66	\$0.00	\$0.00
2032	\$162.49	\$177.47	\$0.00	\$0.00
2033	\$166.05	\$181.39	\$0.00	\$0.00
2034	\$169.68	\$185.38	\$0.00	\$0.00
2035	\$173.39	\$189.45	\$0.00	\$0.00

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		Capitalized Energy Costs 72.1% CF	Total Standard Avoided Energy Cost
	Gas Price	Energy Cost		
	(\$/MMBtu)	(\$/MWh)	(\$/MWh)	(\$/MWh)
	(a)	(b)	(c)	(d)
		(a) x 6.530		(b) + (c)
2028	\$4.97	\$32.45	\$0.00	\$32.45
2029	\$5.11	\$33.37	\$0.00	\$33.37
2030	\$5.43	\$35.46	\$0.00	\$35.46
2031	\$5.57	\$36.37	\$0.00	\$36.37
2032	\$5.72	\$37.35	\$0.00	\$37.35
2033	\$5.91	\$38.59	\$0.00	\$38.59
2034	\$6.09	\$39.77	\$0.00	\$39.77
2035	\$6.26	\$40.88	\$0.00	\$40.88

Columns

- (a) Table 10
- (b) 6.530 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)/(8.76 x 0.75)	(b)+(a)/(8.76 x 0.85)	(b)+(a)/(8.76 x 0.9)
2028	\$149.06	\$32.45	\$55.14	\$52.47	\$51.36
2029	\$152.18	\$33.37	\$56.53	\$53.81	\$52.67
2030	\$155.56	\$35.46	\$59.14	\$56.35	\$55.19
2031	\$158.99	\$36.37	\$60.57	\$57.72	\$56.54
2032	\$162.49	\$37.35	\$62.08	\$59.17	\$57.96
2033	\$166.05	\$38.59	\$63.86	\$60.89	\$59.65
2034	\$169.68	\$39.77	\$65.60	\$62.56	\$61.29
2035	\$173.39	\$40.88	\$67.27	\$64.17	\$62.87

Columns

- (a) Table 3 Column (a)
- (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 4,993 Hours	Off-Peak 3,767 Hours
	(\$/kW-yr)	(\$/MWh)	(\$/MWh)	(\$/MWh)	(\$/MWh)
	(a)	(b)	(c)	(d)	(e)
		(a) / (8.76 x 100.0% x 57%)		(b) + (c)	(c)
2028	\$149.06	\$29.85	\$32.45	\$62.30	\$32.45
2029	\$152.18	\$30.48	\$33.37	\$63.85	\$33.37
2030	\$155.56	\$31.15	\$35.46	\$66.61	\$35.46
2031	\$158.99	\$31.84	\$36.37	\$68.21	\$36.37
2032	\$162.49	\$32.54	\$37.35	\$69.89	\$37.35
2033	\$166.05	\$33.26	\$38.59	\$71.85	\$38.59
2034	\$169.68	\$33.98	\$39.77	\$73.75	\$39.77
2035	\$173.39	\$34.73	\$40.88	\$75.61	\$40.88

Columns

- (a) Table 3 Column (a)
- (b) Table 9 100.0% is the on-peak capacity factor of the Proxy Resource
57.0% 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 72.1% CF
	(\$/kW-yr)	(\$/kW-yr)	(\$/kW-yr)	(\$/MWh)
	(a)	(b)	(c) ((a) - (b))	(d) (c)/(8.760 x 72.1%)
2028	\$149.06	\$162.83	\$0.00	\$0.00
2029	\$152.18	\$166.26	\$0.00	\$0.00
2030	\$155.56	\$169.92	\$0.00	\$0.00
2031	\$158.99	\$173.66	\$0.00	\$0.00
2032	\$162.49	\$177.47	\$0.00	\$0.00
2033	\$166.05	\$181.39	\$0.00	\$0.00
2034	\$169.68	\$185.38	\$0.00	\$0.00
2035	\$173.39	\$189.45	\$0.00	\$0.00

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 6 (Renewable)
Avoided Capacity Costs**

Year	Avoided Firm Capacity Costs	Capacity Cost Allocated to On-Peak Hours
	(\$/kW-yr)	(\$/MWh)

(a)

(b)

(a) / (8.76 x 100.0% x 57%)

2028	\$149.06	\$29.85
2029	\$152.18	\$30.48
2030	\$155.56	\$31.15
2031	\$158.99	\$31.84
2032	\$162.49	\$32.54
2033	\$166.05	\$33.26
2034	\$169.68	\$33.98
2035	\$173.39	\$34.73

Columns

- (a) Table 3 Column (a)
- (b) Table 9 100.0% is the on-peak capacity factor of the Proxy Resource
57.0% is the percent of all hours that are on-peak

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

Year	Proposed Standard		Current Standard		Difference Standard		Proposed Standard		Current Standard		Difference Standard		Proposed Standard		Current Standard		Difference Standard	
	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF
	Wind QF (2)		Wind QF (2)		Wind QF (2)		Wind QF (2)		Fixed Solar QF		Fixed Solar QF		Fixed Solar QF		Fixed Solar QF		Fixed Solar QF	
2016	\$21.89	\$25.80	\$18.77	\$23.11	(\$4.33)	\$22.88	\$27.63	(\$4.75)	\$22.88	\$27.63	(\$4.75)	\$22.88	\$27.63	(\$4.75)	\$22.88	\$27.63	(\$4.75)	\$22.88
2017	\$24.31	\$28.30	\$21.12	\$25.56	(\$4.44)	\$25.59	\$30.25	(\$4.66)	\$25.59	\$30.25	(\$4.66)	\$25.59	\$30.25	(\$4.66)	\$25.59	\$30.25	(\$4.66)	\$25.59
2018	\$25.96	\$30.16	\$22.69	\$27.36	(\$4.67)	\$27.41	\$32.46	(\$5.05)	\$27.41	\$32.46	(\$5.05)	\$27.41	\$32.46	(\$5.05)	\$27.41	\$32.46	(\$5.05)	\$27.41
2019	\$27.01	\$31.97	\$23.66	\$29.11	(\$5.44)	\$28.57	\$34.22	(\$5.64)	\$28.57	\$34.22	(\$5.64)	\$28.57	\$34.22	(\$5.64)	\$28.57	\$34.22	(\$5.64)	\$28.57
2020	\$28.47	\$34.37	\$25.04	\$31.45	(\$6.40)	\$30.09	\$36.81	(\$6.73)	\$30.09	\$36.81	(\$6.73)	\$30.09	\$36.81	(\$6.73)	\$30.09	\$36.81	(\$6.73)	\$30.09
2021	\$30.50	\$37.08	\$26.99	\$34.10	(\$7.11)	\$32.12	\$39.63	(\$7.51)	\$32.12	\$39.63	(\$7.51)	\$32.12	\$39.63	(\$7.51)	\$32.12	\$39.63	(\$7.51)	\$32.12
2022	\$33.41	\$39.93	\$29.82	\$36.89	(\$7.07)	\$35.05	\$42.59	(\$7.55)	\$35.05	\$42.59	(\$7.55)	\$35.05	\$42.59	(\$7.55)	\$35.05	\$42.59	(\$7.55)	\$35.05
2023	\$37.43	\$42.77	\$33.76	\$39.66	(\$5.89)	\$39.25	\$45.63	(\$6.38)	\$39.25	\$45.63	(\$6.38)	\$39.25	\$45.63	(\$6.38)	\$39.25	\$45.63	(\$6.38)	\$39.25
2024	\$41.36	\$48.24	\$37.61	\$28.13	\$9.48	\$43.33	\$34.14	\$9.20	\$43.33	\$34.14	\$9.20	\$43.33	\$34.14	\$9.20	\$43.33	\$34.14	\$9.20	\$43.33
2025	\$43.48	\$49.89	\$39.65	\$29.34	\$10.31	\$45.49	\$35.48	\$10.01	\$45.49	\$35.48	\$10.01	\$45.49	\$35.48	\$10.01	\$45.49	\$35.48	\$10.01	\$45.49
2026	\$45.18	\$50.19	\$41.27	\$29.22	\$12.06	\$47.25	\$35.48	\$11.77	\$47.25	\$35.48	\$11.77	\$47.25	\$35.48	\$11.77	\$47.25	\$35.48	\$11.77	\$47.25
2027	\$47.20	\$51.89	\$43.20	\$30.46	\$12.74	\$49.36	\$36.86	\$12.50	\$49.36	\$36.86	\$12.50	\$49.36	\$36.86	\$12.50	\$49.36	\$36.86	\$12.50	\$49.36
2028	\$49.46	\$55.30	\$32.68	\$33.43	(\$0.75)	\$40.58	\$39.96	\$0.62	\$41.72	\$39.96	\$0.62	\$41.72	\$39.96	\$0.62	\$41.72	\$39.96	\$0.62	\$41.72
2029	\$50.74	\$56.72	\$33.60	\$34.41	(\$0.81)	\$41.67	\$41.08	\$0.60	\$42.83	\$41.08	\$0.60	\$42.83	\$41.08	\$0.60	\$42.83	\$41.08	\$0.60	\$42.83
2030	\$53.22	\$57.92	\$35.70	\$35.16	\$0.54	\$43.95	\$41.96	\$1.99	\$45.13	\$41.96	\$1.99	\$45.13	\$41.96	\$1.99	\$45.13	\$41.96	\$1.99	\$45.13
2031	\$54.52	\$60.76	\$36.62	\$37.52	(\$0.90)	\$45.04	\$44.46	\$0.58	\$46.26	\$44.46	\$0.58	\$46.26	\$44.46	\$0.58	\$46.26	\$44.46	\$0.58	\$46.26
2032	\$55.90	\$62.23	\$37.60	\$38.51	(\$0.91)	\$46.21	\$45.60	\$0.62	\$47.45	\$45.60	\$0.62	\$47.45	\$45.60	\$0.62	\$47.45	\$45.60	\$0.62	\$47.45
2033	\$57.55	\$63.26	\$38.85	\$39.03	(\$0.19)	\$47.65	\$46.28	\$1.37	\$48.92	\$46.28	\$1.37	\$48.92	\$46.28	\$1.37	\$48.92	\$46.28	\$1.37	\$48.92
2034	\$59.14	\$65.14	\$40.03	\$40.40	(\$0.37)	\$49.03	\$47.80	\$1.23	\$50.32	\$47.80	\$1.23	\$50.32	\$47.80	\$1.23	\$50.32	\$47.80	\$1.23	\$50.32
2035	\$60.68	\$67.24	\$41.15	\$41.99	(\$0.84)	\$50.34	\$49.54	\$0.80	\$51.66	\$49.54	\$0.80	\$51.66	\$49.54	\$0.80	\$51.66	\$49.54	\$0.80	\$51.66

15 Year (2016 - 2030) Nominal levelized Price at 6.660% Discount Rate (1) \$/MWh \$34.52 \$39.80 (\$5.28) \$29.25 \$30.47 (\$1.23) \$34.74 \$36.07 (\$1.34) \$34.89 \$36.07 (\$1.18)

Notes: (1) Discount Rate - 2015 IRP Discount Rate

(2) Avoided cost prices have been reduced by a wind integration charge of \$3.06/MWh (\$2014) for wind QFs located resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .

If the QF wind resource is not in PacifiCorp's BAA, prices will be increased by the \$3.06/MWh (\$2014) integration charges

15 Year (2017 - 2031) Nominal levelized Price at 6.660% Discount Rate (1) \$/MWh \$36.70 \$42.16 (\$5.46) \$30.67 \$31.55 (\$0.88) \$36.43 \$37.32 (\$0.89) \$36.64 \$37.32 (\$0.68)

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

Year	Proposed Renewable		Current Renewable		Difference Renewable		Proposed Renewable		Current Renewable		Difference Renewable	
	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF	Fixed	Base Load QF
2016	\$21.89	\$25.80	\$25.80	\$25.80	(\$3.90)		\$18.77	\$23.11	\$23.11	\$27.63	\$27.63	(\$4.75)
2017	\$24.31	\$28.30	\$28.30	\$28.30	(\$3.99)		\$21.12	\$25.56	\$25.56	\$30.25	\$30.25	(\$4.66)
2018	\$25.96	\$30.16	\$30.16	\$30.16	(\$4.20)		\$22.69	\$27.36	\$27.36	\$32.46	\$32.46	(\$5.05)
2019	\$27.01	\$31.97	\$31.97	\$31.97	(\$4.95)		\$23.66	\$29.11	\$29.11	\$34.22	\$34.22	(\$5.64)
2020	\$28.47	\$34.37	\$34.37	\$34.37	(\$5.89)		\$25.04	\$31.45	\$31.45	\$36.81	\$36.81	(\$6.73)
2021	\$30.50	\$37.08	\$37.08	\$37.08	(\$6.58)		\$26.99	\$34.10	\$34.10	\$39.63	\$39.63	(\$7.51)
2022	\$33.41	\$39.93	\$39.93	\$39.93	(\$6.52)		\$29.82	\$36.89	\$36.89	\$42.59	\$42.59	(\$7.55)
2023	\$37.43	\$42.77	\$42.77	\$42.77	(\$5.33)		\$33.76	\$39.66	\$39.66	\$45.63	\$45.63	(\$6.38)
2024	\$41.36	\$98.47	\$98.47	\$98.47	(\$57.10)		\$37.61	\$78.36	\$78.36	\$89.35	\$89.35	(\$46.02)
2025	\$43.48	\$100.64	\$100.64	\$100.64	(\$57.16)		\$39.65	\$80.09	\$80.09	\$91.15	\$91.15	(\$45.66)
2026	\$45.18	\$102.73	\$102.73	\$102.73	(\$57.55)		\$41.27	\$81.75	\$81.75	\$92.46	\$92.46	(\$45.21)
2027	\$47.20	\$104.89	\$104.89	\$104.89	(\$57.68)		\$43.20	\$83.46	\$83.46	\$94.22	\$94.22	(\$44.85)
2028	\$86.65	\$107.09	\$107.09	\$107.09	(\$20.44)		\$69.86	\$85.22	\$85.22	\$95.99	\$95.99	(\$16.44)
2029	\$88.46	\$109.22	\$109.22	\$109.22	(\$20.76)		\$71.32	\$86.91	\$86.91	\$97.70	\$97.70	(\$16.53)
2030	\$90.41	\$111.40	\$111.40	\$111.40	(\$20.99)		\$72.90	\$88.64	\$88.64	\$99.44	\$99.44	(\$16.37)
2031	\$92.34	\$113.68	\$113.68	\$113.68	(\$21.34)		\$74.44	\$90.44	\$90.44	\$100.98	\$100.98	(\$16.20)
2032	\$94.43	\$116.13	\$116.13	\$116.13	(\$21.70)		\$76.13	\$92.41	\$92.41	\$103.28	\$103.28	(\$16.67)
2033	\$96.50	\$118.54	\$118.54	\$118.54	(\$22.05)		\$77.79	\$94.32	\$94.32	\$104.81	\$104.81	(\$16.38)
2034	\$98.63	\$121.01	\$121.01	\$121.01	(\$22.37)		\$79.52	\$96.27	\$96.27	\$106.42	\$106.42	(\$16.06)
2035	\$100.77	\$123.53	\$123.53	\$123.53	(\$22.76)		\$81.24	\$98.28	\$98.28	\$108.66	\$108.66	(\$16.57)

15 Year (2016 - 2030) Nominal levelized Price at 6.660% Discount Rate (1)
\$/MWh \$39.41 \$57.97 (\$18.55) \$34.14 \$48.64 (\$14.50) \$39.87 \$55.81 (\$15.94) \$40.02 \$55.81 (\$15.79)

Notes: (1) Discount Rate - 2015 IRP Discount Rate

(2) Avoided cost prices have been reduced by a wind integration charge of \$3.06/MWh (\$2014) for wind QFs located resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .

If the QF wind resource is not in PacifiCorp's BAA, prices will be increased by the \$3.06/MWh (\$2014) integration charges

15 Year (2017 - 2031) Nominal levelized Price at 6.660% Discount Rate (1)
\$/MWh \$43.46 \$63.70 (\$20.24) \$37.44 \$53.09 (\$15.66) \$43.53 \$60.68 (\$17.15) \$43.74 \$60.68 (\$16.94)

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)

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

2015	\$825	\$64.07	\$46.13	\$4.29	\$58.54	\$122.61
2016		\$64.84	\$46.69	\$4.34	\$59.24	\$124.08
2017		\$66.27	\$47.72	\$4.44	\$60.56	\$126.83
2018		\$67.86	\$48.87	\$4.55	\$62.02	\$129.88
2019		\$69.49	\$50.04	\$4.66	\$63.51	\$133.00
2020		\$71.16	\$51.24	\$4.77	\$65.03	\$136.19
2021		\$72.87	\$52.47	\$4.88	\$66.58	\$139.45
2022		\$74.55	\$53.68	\$4.99	\$68.11	\$142.66
2023		\$76.26	\$54.91	\$5.10	\$69.65	\$145.91
2024		\$78.01	\$56.17	\$5.22	\$71.26	\$149.27
2025		\$79.73	\$57.41	\$5.33	\$72.82	\$152.55
2026		\$81.48	\$58.67	\$5.45	\$74.42	\$155.90
2027		\$83.27	\$59.96	\$5.57	\$76.06	\$159.33
2028		\$85.10	\$61.28	\$5.69	\$77.73	\$162.83
2029		\$86.89	\$62.57	\$5.81	\$79.37	\$166.26
2030		\$88.80	\$63.95	\$5.94	\$81.12	\$169.92
2031		\$90.75	\$65.36	\$6.07	\$82.91	\$173.66
2032		\$92.75	\$66.80	\$6.20	\$84.72	\$177.47
2033		\$94.79	\$68.27	\$6.34	\$86.60	\$181.39
2034		\$96.88	\$69.77	\$6.48	\$88.50	\$185.38
2035		\$99.01	\$71.30	\$6.62	\$90.44	\$189.45

Source: (a)(c)(d) Plant Costs - 2015 IRP - Table 6.1 & 6.2
 (b) = (a) x Payment Factor
 (e) = (d) x (8.76 x 33%) + (c)
 (f) = (b) + (e)

SCCT Frame ("F"x1) - West Side Options (1500')		
212	MW Plant capacity	MW
\$ 820	Plant capacity cost	\$/kW
\$ 10.73	Fixed O&M & Capitalized O&M	\$/kW-yr
\$ 35.13	Fixed Pipeline	\$/kW-yr
\$ 45.86	Fixed O&M Including Fixed Pipeline & Capitalized	\$/kW-yr
\$ 4.27	Variable O&M and Other Costs	\$/MWH
7.767%	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)

CCCT (Dry "J" Adv 1x1) - West Side Options (1500')

2015	\$872	\$67.00	\$31.01	\$2.25	\$45.25	\$112.25			
2016		\$67.81	\$31.39	\$2.28	\$45.79	\$113.60			
2017		\$69.30	\$32.08	\$2.33	\$46.80	\$116.10			
2018		\$70.96	\$32.85	\$2.39	\$47.95	\$118.91			
2019		\$72.66	\$33.64	\$2.45	\$49.11	\$121.77			
2020		\$74.40	\$34.45	\$2.51	\$50.30	\$124.70			
2021		\$76.19	\$35.28	\$2.57	\$51.51	\$127.70			
2022		\$77.94	\$36.09	\$2.63	\$52.70	\$130.64			
2023		\$79.73	\$36.92	\$2.69	\$53.91	\$133.64			
2024		\$81.56	\$37.77	\$2.75	\$55.14	\$136.70			
2025		\$83.35	\$38.60	\$2.81	\$56.35	\$139.70			
2026		\$85.18	\$39.45	\$2.87	\$57.58	\$142.76			
2027		\$87.05	\$40.32	\$2.93	\$58.83	\$145.88			
2028		\$88.97	\$41.21	\$2.99	\$60.09	\$149.06	\$4.97	\$32.45	\$56.05
2029		\$90.84	\$42.08	\$3.05	\$61.34	\$152.18	\$5.11	\$33.37	\$57.46
2030		\$92.84	\$43.01	\$3.12	\$62.72	\$155.56	\$5.43	\$35.46	\$60.09
2031		\$94.88	\$43.96	\$3.19	\$64.11	\$158.99	\$5.57	\$36.37	\$61.54
2032		\$96.97	\$44.93	\$3.26	\$65.52	\$162.49	\$5.72	\$37.35	\$63.08
2033		\$99.10	\$45.92	\$3.33	\$66.95	\$166.05	\$5.91	\$38.59	\$64.88
2034		\$101.28	\$46.93	\$3.40	\$68.40	\$169.68	\$6.09	\$39.77	\$66.64
2035		\$103.51	\$47.96	\$3.47	\$69.88	\$173.39	\$6.26	\$40.88	\$68.33

Table 9
Total Cost of Displaceable Resources

Sources, Inputs and Assumptions

- Source: (a)(c)(d) Plant Costs - 2015 IRP - Table 6.1 & 6.2
 (b) = (a) x 0.07682
 (e) = (d) x (8.76 x 72.1%) + (c)
 (f) = (b) + (e)
 (g) Gas Price Forecast
 (h) = 6530 x (g) / 1000
 (i) = (f) / (8.76 x 'Capacity Factor') + (h)

CCCT (Dry "J" Adv 1x1) - West Side Options (1500')

CCCT Statistics	MW	Percent	Cap Cost	Fixed
CCCT (Dry "J" Adv 1x1)	434	91.0%	\$906	\$30.82
CCCT Duct Firing (Dry "J" Adv 1x1)	<u>43</u>	<u>9.0%</u>	<u>\$481</u>	<u>\$30.93</u>
Capacity Weighted	477	100.0%	\$867	\$30.83

CCCT Statistics	MW	CF	aMW	Percent	Variable	Heat Rate
CCCT (Dry "J" Adv 1x1)	434	78.0%	339	98.5%	\$2.27	6,495
CCCT Duct Firing (Dry "J" Adv 1x1)	<u>43</u>	<u>12.0%</u>	<u>5</u>	<u>1.5%</u>	<u>0.10</u>	<u>8,611</u>
Energy Weighted	477	72.1%	344	100.0%	\$2.24	6,530

Rounded

CCCT Duct Firing Plant Costs - 2015 IRP - Table 6.1 & 6.2

CCCT	Duct Firing	
434	43	MW Plant capacity
\$906	\$481	Plant capacity cost
\$7.50	\$0.00	Fixed O&M & Capitalized O&M
<u>\$23.33</u>	<u>\$30.93</u>	Fixed Pipeline
\$30.82	\$30.93	Fixed O&M Including Fixed Pipeline & Capitalized O&M (\$/kW-Yr)
\$2.27	\$0.10	Variable O&M and Other Costs
6,495	8,611	Heat Rate in btu/kWh
7.682%	7.682%	Payment Factor
78%	12%	Capacity Factor
	72.1%	Energy Weighted Capacity Factor
	100.0%	Capacity Factor - On-peak 72.1% / 57% (percent of hours on-peak)

Company Official Inflation Forecast - Dated March 2016

2015	0.6%	2021	2.4%	2027	2.2%	2033	2.2%
2016	1.2%	2022	2.3%	2028	2.2%	2034	2.2%
2017	2.2%	2023	2.3%	2029	2.1%	2035	2.2%
2018	2.4%	2024	2.3%	2030	2.2%	2036	2.2%
2019	2.4%	2025	2.2%	2031	2.2%	2037	2.2%
2020	2.4%	2026	2.2%	2032	2.2%	2038	2.3%

Table 10
Gas Price Forecast
\$/MMBtu

Year	Burner tip West Side Gas Fuel Cost
2028	\$4.97
2029	\$5.11
2030	\$5.43
2031	\$5.57
2032	\$5.72
2033	\$5.91
2034	\$6.09
2035	\$6.26

Source

Official Market Price Forecast dated March 2016

Table 11
Wind Integration Cost

Year	Wind Integration Cost \$/MWh
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2014	\$3.06
2015	\$3.08
2016	\$3.12
2017	\$3.19
2018	\$3.27
2019	\$3.35
2020	\$3.43
2021	\$3.51
2022	\$3.59
2023	\$3.67
2024	\$3.75
2025	\$3.83
2026	\$3.91
2027	\$4.00
2028	\$4.09
2029	\$4.18
2030	\$4.27
2031	\$4.36
2032	\$4.46
2033	\$4.56
2034	\$4.66
2035	\$4.76

Note: Wind Integration Charge is \$3.06 (2014 \$ per MWh)
2015 IRP Volume II-Appendix H, Table H.3

Table 12
2015 IRP WY Wind Resource
43% Capacity Factor

Year	Estimated Capital Cost \$/kW (a)	Capital Cost at Real Levelized Rate \$/kW-yr (b)	Fixed O&M \$/kW-yr (c)	Fixed Costs \$/MWh (d)	Variable O&M \$/MWh (e)	Tax Credit \$/MWh (f)	Avoided Cost \$/MWh (g)	Wind Integration Cost \$/MWh (h)
2015 IRP WY Wind Resource - 43% Capacity Factor								
2015	\$2,169	\$160.48	\$34.67	\$51.81	\$0.67	\$0.00	\$52.48	\$3.08
2016		\$162.41	\$35.08	\$52.43	\$0.68	\$0.00	\$53.11	\$3.12
2017		\$165.98	\$35.85	\$53.58	\$0.69	\$0.00	\$54.27	\$3.19
2018		\$169.96	\$36.71	\$54.87	\$0.71	\$0.00	\$55.58	\$3.27
2019		\$174.04	\$37.59	\$56.18	\$0.73	\$0.00	\$56.91	\$3.35
2020		\$178.22	\$38.49	\$57.53	\$0.75	\$0.00	\$58.28	\$3.43
2021		\$182.50	\$39.41	\$58.91	\$0.77	\$0.00	\$59.68	\$3.51
2022		\$186.70	\$40.32	\$60.27	\$0.79	\$0.00	\$61.06	\$3.59
2023		\$190.99	\$41.25	\$61.65	\$0.81	\$0.00	\$62.46	\$3.67
2024		\$195.38	\$42.20	\$63.07	\$0.83	\$0.00	\$63.90	\$3.75
2025		\$199.68	\$43.13	\$64.46	\$0.85	\$0.00	\$65.31	\$3.83
2026		\$204.07	\$44.08	\$65.88	\$0.87	\$0.00	\$66.75	\$3.91
2027		\$208.56	\$45.05	\$67.33	\$0.89	\$0.00	\$68.22	\$4.00
2028		\$213.15	\$46.04	\$68.81	\$0.91	\$0.00	\$69.72	\$4.09
2029		\$217.63	\$47.01	\$70.26	\$0.93	\$0.00	\$71.19	\$4.18
2030		\$222.42	\$48.04	\$71.80	\$0.95	\$0.00	\$72.75	\$4.27
2031		\$227.31	\$49.10	\$73.38	\$0.97	\$0.00	\$74.35	\$4.36
2032		\$232.31	\$50.18	\$74.99	\$0.99	\$0.00	\$75.98	\$4.46
2033		\$237.42	\$51.28	\$76.64	\$1.01	\$0.00	\$77.65	\$4.56
2034		\$242.64	\$52.41	\$78.33	\$1.03	\$0.00	\$79.36	\$4.66
2035		\$247.98	\$53.56	\$80.05	\$1.05	\$0.00	\$81.10	\$4.76

Sources, Inputs and Assumptions

Source: (c)(f) Plant Costs 2015 IRP (Table 6.2) in \$2014
(a) Plant capacity cost
(b) = (a) x 0.0739902205884359
(d) = ((b) + (c)) / (8.76 x 43.0%)
(g) = (d) + (f)
(h) 2015 IRP (Table 6.2) in \$2014

2015 IRP WY Wind Resource - 43% Capacity Factor	
Wind	Cost and Input Assumptions

\$2,156	Plant capacity cost	\$/kW-yr
\$34.46	Fixed O&M, plus on-going capital cost	\$/kW-yr
	2015 IRP (Table 6.2) in \$2014	
\$0.67	Variable O&M	\$/MWh
-	Tax Credit	\$/MWh
7.399%	Payment Factor	
43%	Capacity Factor	

Official Inflation Forecast Dated March 2016 Forecast							
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2015	0.6%	2021	2.4%	2027	2.2%	2033	2.2%
2016	1.2%	2022	2.3%	2028	2.2%	2034	2.2%
2017	2.2%	2023	2.3%	2029	2.1%	2035	2.2%
2018	2.4%	2024	2.3%	2030	2.2%	2036	2.2%
2019	2.4%	2025	2.2%	2031	2.2%	2037	2.2%
2020	2.4%	2026	2.2%	2032	2.2%	2038	2.3%

Table 13
2015 IRP Wind Resource Costs
Adjusted to On-Peak / Off-Peak Prices

Year	Renewable Price	On-Peak / Off-Peak Factors		On-Peak / Off-Peak Prices	
	\$/MWH	On-Peak	Off-Peak	On-Peak	Off-Peak
	(a)	(b)	(c)	(d)	(e)
				(a) x (b)	(a) x (c)
2018	\$55.58	1.1064	0.8644	\$61.49	\$48.04
2019	\$56.91	1.1057	0.8638	\$62.93	\$49.16
2020	\$58.28	1.0941	0.8791	\$63.77	\$51.23
2021	\$59.68	1.0865	0.8892	\$64.85	\$53.07
2022	\$61.06	1.0915	0.8829	\$66.65	\$53.91
2023	\$62.46	1.0953	0.8792	\$68.42	\$54.92
2024	\$63.90	1.0925	0.8819	\$69.81	\$56.36
2025	\$65.31	1.0902	0.8851	\$71.20	\$57.81
2026	\$66.75	1.0891	0.8862	\$72.70	\$59.16
2027	\$68.22	1.0872	0.8888	\$74.17	\$60.63
2028	\$69.72	1.0887	0.8872	\$75.90	\$61.86
2029	\$71.19	1.0877	0.8879	\$77.43	\$63.21
2030	\$72.75	1.0898	0.8855	\$79.29	\$64.42
2031	\$74.35	1.0879	0.8863	\$80.89	\$65.90
2032	\$75.98	1.0871	0.8891	\$82.60	\$67.56
2033	\$77.65	1.0855	0.8909	\$84.29	\$69.18
2034	\$79.36	1.0848	0.8925	\$86.09	\$70.82
2035	\$81.10	1.0803	0.8975	\$87.62	\$72.79

Columns

- (a) Table 12 Column (f)
- (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 – AUGUST 2016

**PACIFIC POWER
AVOIDED COST CALCULATION**

**STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE
QUALIFYING FACILITIES**

OREGON –AUGUST 2016

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 23, 2015.

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 2015 IRP which was acknowledged by the Commission on February 29, 2016.

Table 1 presents an excerpt from the 2015 IRP Table 8.7 and shows that the next major resource acquisition is a Combine Cycle Combustion Turbine (CCCT) starting in 2028. Therefore, the resource sufficiency period for the standard avoided cost rates is from 2016-2027 and the deficiency period starts in 2028.

The start of the renewable resource deficiency period in this filing is revised to start in January 1, 2028, pursuant to Order No. 16-307 in docket UM 1729. The Production Tax Credit sunsets prior to this date, so it is not included as a credit against the proxy resource cost.

Avoided Cost Calculation

Based on the 2015 IRP preferred portfolio shown in **Table 1**, the standard avoided cost calculation is separated into two distinct periods: (1) a period of standard resource sufficiency (2016 through 2027); and (2) a period of standard resource deficiency (2028 and beyond). During the resource sufficiency period (2016 through 2027), 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 2016 through 2027 and the renewable resource deficiency period starts in 2028. During the renewable resource sufficiency period (2016 through 2027), the renewable avoided energy costs are based on weighted market prices.

During the resource deficiency period, standard avoided costs are the fixed and variable costs of a proxy resource that could be avoided or deferred. The current thermal proxy resource used to set standard avoided cost rates beginning in 2028 is a west side CCCT from the 2015 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 in this case are zero because the costs of an SCCT exceed those of the CCCT. 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 2015 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 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 a QF resource.

¹ 477 MW CCCT (Dry "J" Adv 1x1) - West Side Options (1500') –available in 2028 as listed in Tables 6.1 and 6.2 of the 2015 IRP. Fuel costs are from the Company's March 2016 Official Forward Price Curve (1603 OFPC).

² SCCT Frame ("F"x1) - West Side Options (1500'), as listed in Tables 6.1 and 6.2 of the 2015 IRP.

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.

Because energy generated by a QF may vary, we have prepared total standard avoided costs 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 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 2016 Official Forward Price Curve (1603 OFPC). **Table 10** shows the natural gas price used in this avoided cost calculation.

Table 11 shows wind integration costs used in 2015 IRP.

Table 12 shows the calculation of total resource cost of the renewable proxy plant from 2015 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 2016-2027. For 2028 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the proxy CCCT. The on-peak price also includes a capacity adder based on the fixed costs a thermal proxy CCCT (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 2016-2027. For 2028 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the proxy CCCT. The on-peak price also includes a capacity adder calculated based on fixed costs of the thermal proxy CCCT (in \$/kW-yr) adjusted by the expected capacity contribution of a wind QF as identified in the 2015 IRP (wind: 25.4%). The adjusted capacity adder (in \$/kW-yr) is allocated to on peak hours by using the on peak capacity factor of a wind QF resource. Standard avoided cost rates for a wind QF are reduced by a wind integration charge of \$3.06/MWh (\$2014).

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 2016-2027. For 2028 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the proxy CCCT. 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 2015 IRP (fixed solar: 32.2%, tracking solar: 36.7%). 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.

Exhibit 5- Renewable Base Load tab shows the calculation of proposed standard renewable avoided cost rates for a Renewable Base Load QF. On- and off-peak renewable avoided cost rates are based on blended market rates for 2016-2027. For 2028 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. 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 Base Load QF relative to the avoided renewable wind 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. The renewable avoided cost rates for a base load QF are increased by the avoided wind integration charge of \$3.06/MWh (\$2014) during the renewable resource deficiency period.

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 2016-2027. For 2028 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.

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 2016-2027. For 2028 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. 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 wind 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. The standard renewable avoided cost rates for fixed and tracking solar QF resources are increased by the avoided wind integration charge of \$3.06/MWh (\$2014) during the renewable resource deficiency period.

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**.