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July 12, 2018

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street, SE, Suite 100
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Attn: Filing Center

RE: UM 1729—PacifiCorp's Reply Brief

In response to the Public Utility Commission's May 23, 2018 request for legal briefing on the issue of whether to include transmission costs in Pacific Power's avoided cost prices, PacifiCorp d/b/a Pacific Power provides the attached Reply Brief.

Please direct any questions on this filing to Natasha Siores at (503) 813-6583.

Sincerely,

Etta Lockey,
Vice President, Regulation

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM 1729

In the Matter of PACIFICORP d/b/a PACIFIC POWER Application to Update Schedule 37 Qualifying Facility Information.	PACIFICORP'S REPLY BRIEF

PacifiCorp d/b/a Pacific Power submits this reply brief in response to the Public Utility Commission of Oregon's (Commission) request at the May 22, 2018 Public Meeting.

I. EXECUTIVE SUMMARY

It is a federal requirement—embodied in statute,[1] regulation,[2] and precedent[3]—that utility customers remain financially indifferent to a utility's purchase of qualifying facility (QF) power. This Commission has long recognized this requirement in its implementation of PURPA.[4]

The customer indifference requirement informs every aspect of a utility's interactions with QFs under the Public Utility Regulatory Policies Act of 1978 (PURPA), including the

[1] *See, e.g.*, 16 U.S.C. § 824a-3(b) ("No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."). Section 210(d) of PURPA defines "incremental cost of alternative electric energy" as "the cost to the electric utility of the electric energy which, **but for** the purchase from [the QF], such utility would generate or purchase from another source." 16 U.S.C. § 824a-3 (emphasis added).

[2] *See, e.g.*, 18 C.F.R. § 292.304(a)(2) ("Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases."); 18 C.F.R. § 292.101(b)(6) (defining "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, **but for** the purchase from the qualifying facility…, such utility would generate itself or purchase from another source.") (emphasis added); *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 45 (1980) (discussing industry comments on section 304(a) of the then-new regulations and noting that utility customers would be kept whole, paying the same rates as they would have paid had the utility not purchased energy and capacity from the qualifying facility).

[3] *See, e.g., S. Cal. Edison Co., San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269 at p. 62,080 (1995) ("The intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives.").

[4] *See, e.g., In the Matter of Portland Gen. Elec. Co.*, Docket No. UM 1894, Order No. 18-025 at 3 (2018) ("In implementing PURPA, we have, on a number of occasions, reaffirmed our intention 'to encourage the economically efficient development' of QFs, 'while protecting ratepayers by ensuring that utilities pay rates equal to that which they would have incurred in lieu of purchasing QF power.' Our orders implementing PURPA reflect our efforts to balance encouraging QF development with maintaining ratepayer indifference.") (internal citation omitted).

development of avoided cost rates that must not exceed the utility's avoided costs. The particular avoided cost rate question at issue in this proceeding is whether PacifiCorp's avoided cost rates should include the cost of segment D.2 because that transmission line is facilitating the interconnection of additional generators in the constrained area where PacifiCorp's proxy generating unit is located.[5] The answer is no. Neither the law nor the facts support increasing avoided cost rates in this way.

Avoided cost ratemaking has well-understood norms regarding the types of costs that are considered "avoided." Federal Energy Regulatory Commission (FERC) regulations enumerate several categories of costs that states may consider in setting QF rates, none of which include the capital costs of transmission.[6] While FERC allows states some latitude in implementing these avoided cost rate regulations, the notion proposed in this docket—that Oregon QFs are entitled to increased avoided cost rates to reflect the cost of a backbone transmission line in Wyoming on the theoretical assumption that construction of the line will be avoided by PacifiCorp's purchase of Oregon QF power—is a stark departure from those norms. As discussed in detail below, FERC case law sets a high bar that requires any such novel "adders" to avoided costs rates be based on real, not theoretical, costs. This Commission's own policies reflect FERC's high bar by establishing a presumption *against* including transmission costs in rates unless there is "compelling" evidence that transmission costs associated with the on-system proxy resource are both *avoidable* and *actually avoided* by the purchase of QF power.

That high bar has not been satisfied here. Segment D.2 will create additional interconnection capability, which means additional generators will be able to secure

[5] The proxy resource is the resource identified in the Integrated Resource Plan (IRP) as the next, future resource needed to serve load. This hypothetical resource is the one assumed to be avoided by accepting QF power, and its costs become the basis for avoided cost rates.
[6] 18 C.F.R. § 292.304(e).

interconnection to PacifiCorp's system. These additional generators impact the economics of constructing segment D.2. This physical and economic relationship between segment D.2 and the generators should not, however, be misinterpreted as a *causal* relationship. Segment D.2 is not a "but for" result of new interconnection requests (or the proxy resource) in Wyoming. Rather, PacifiCorp is constructing segment D.2 in accordance with its long-standing, federally regulated, transmission expansion plan because segment D.2 provides significant reliability and other system benefits beyond just increased interconnection. This means the construction of segment D.2 is not avoidable even in the absence of the Wyoming generators or the proxy resource, much less as a result of PacifiCorp's purchase of power from QFs in Oregon. Including the costs of segment D.2 in avoided cost rates would therefore violate: (1) FERC and this Commission's policies because no "real" transmission costs will *actually* be avoided by the QF purchases, so there is no justification for a special avoided cost rate adder; and (2) PURPA's customer indifference standard because PacifiCorp's customers would be paying increased rates for QF power based on the theoretical assumption that a line will be avoided, when in fact its construction is not actually avoided.

II. PROCEDURAL BACKGROUND

The issue before the Commission is the proper application of the rebuttable presumption *against* including transmission costs in avoided cost rates when the proxy resource is on-system, as is the case with PacifiCorp's pending avoided cost rates. PacifiCorp first offers an overview of the procedural background leading to the Commission's establishment of this rebuttable presumption to provide important context for its accurate application.

A. Order No. 14-058 – Categorical Exclusion of Transmission Costs

In Phase I of docket UM 1610, the Commission examined several generic PURPA issues, including "Issue 4B" related to whether Oregon utilities must include in avoided cost rates the costs of transmission over a third party system associated with two different kinds of proxy resources: off-system and on-system.[7] In short, the Commission only recognized an avoided transmission cost if an entire transmission service arrangement across a third party system could be avoided because of the location of the off-system proxy resource versus the on-system QF, but it categorically excluded the consideration of avoided transmission costs where both the proxy resource and the QF are both on-system and no third-party transmission service arrangement is avoided.

More specifically, the Commission concluded that if the proxy resource is an off-system resource (*i.e.,* interconnected with a third party system and transmitted or "wheeled" over that third party system to the utility's system), then the cost of procuring transmission service over the third party system is deemed avoided by the utility's purchase of an on-system QF's power and, therefore, included in the calculation of avoided cost prices.[8] By contrast, the Commission concluded that if the proxy resource is an on-system resource (*i.e.,* interconnected with the utility's system and not "wheeled" over any third party system), then there would be no third party transmission service costs for the utility to avoid by purchasing the on-system QF power

[7] Docket No. UM 1610 had its origins in a separate docket concerning Idaho Power Company's application to revise its methodology for standard avoided cost prices in Docket No. UM 1593. *In the Matter of Idaho Power Company*, Dockets UM 1590 and UM 1593, Order No. 12-146, Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices and Motion for Temporary Stay of Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities (Apr. 25, 2012). Upon recognition of broader issues related to QF contracting, avoided cost pricing, and the transmission of QF power, the Commission ordered the establishment of a separate, generic proceeding to further examine these issues. *Id*. at 2. On October 25, 2012, the Chief Administrative Law Judge (Chief ALJ) adopted a finalized list of seven QF issues for examination, to be conducted in phases, by the Commission. *In the Matter of Public Utility Commission of Oregon Investigation Into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Issues List Finalized (Oct. 25, 2012).
[8] *In the Matter of Public Utility Commission of Oregon Investigation Into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 14-058 at 17 (Feb. 24, 2014) (Order No. 14-058).

and, therefore, no reflection of third party transmission costs in avoided cost rates.[9] Specifically, the Commission concluded:

> *If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs, and thus the costs of third-party transmission are not included in the calculation of avoided cost prices. This is the situation for Pacific Power.*[10]

The effect of this finding reached by the Commission was a categorical exclusion of avoided transmission costs when the proxy is an on-system resource.

B. Order No. 16-174 – Creation of Rebuttable Presumption *Against* Inclusion of Transmission Costs

In Phase II of docket UM 1610, the Commission modified its resolution to Issue 4B (now "Issue 2" in Phase II) after several parties raised concerns over the impact of the Commission's *per se* categorical exclusion on PacifiCorp's future avoided cost calculations.[11] PacifiCorp objected to the notion that avoided cost pricing should include transmission costs "associated with" an on-system proxy resource, as no party had demonstrated a utility would avoid transmission costs—third party or other—when the utility's proxy resource is on-system. PacifiCorp argued that attributing transmission upgrades to a particular proxy resource and then deeming those transmission upgrades avoidable along with the proxy resource fails to appreciate that federal policy, not proxy resource location, drives the company's regional transmission expansion plans. Further, even if specific transmission costs might be incurred to accommodate an on-system proxy resource, these costs would not be avoided by purchases from QF resources.

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[9] *Id*.
[10] *Id.*
[11] *In the Matter of Public Utility Commission of Oregon Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 16-174 at 6 (May 13, 2016) (Order No. 16-174).

In response to confusion over the drivers behind the Gateway West project (which includes many segments, including D.2) in particular, PacifiCorp provided testimony that the costs of the project were not avoidable by avoiding the proxy resource:

> Completion of the Gateway West transmission project is not directly tied to the proxy renewable resource and will not be avoided due to the addition of renewable QFs in Oregon. OneEnergy is correct that transmission constraints exist in the bubble where the proxy resource is planned; however, ***the constraints exist regardless of whether the proxy resource is built or not***. The purpose of the Gateway West transmission project is to alleviate existing transmission constraints and improve the ability to deliver energy from all existing resources to load. Additionally, Gateway West's planned in service date assumed in the 2013 IRP was more than five years before the proxy resource's in-service date. ***In short, the proxy resource does not create the need for Gateway West***.[12]

In response to intervenor concerns, the Commission expanded its previous holding, but acknowledged the importance of proceeding with caution on this issue. The Commission concluded that its prior determination that incremental transmission costs were precluded "from *ever* being included in the avoided costs calculation, even if a party demonstrates that the purchase of QF power actually avoided incremental transmission costs," was too conclusive.[13] The Commission modified the resolution from Order No. 14-058 and established the following "rebuttable presumption":

> *If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there is a rebuttable presumption that there are no avoided transmission costs, and thus the costs of third-party transmission are not included in the calculation of avoided cost prices. This is the situation for Pacific Power*.[14]

The order explained that QFs could overcome this rebuttable presumption by demonstrating, through factual evidence, that real transmission costs could *actually* be avoided

[12] Docket No. UM 1610, Exhibit PAC-1100, Response Testimony of Brian S. Dickman (July 2015) (emphasis added).
[13] Order No. 16-174 at 8.
[14] *Id*.

by a utility's purchase of power from the QF.[15] The Commission acknowledged the complexity of such a rebuttable presumption, stating that it recognized PacifiCorp's advisement "that a factual determination about whether there are avoidable transmission costs associated with a renewable proxy resource, will involve resolving complex legal questions, reconciling state and federal policy issues, and working through implementation intricacies."[16]

C. Docket UM 1729 – Application of the Rebuttable Presumption

On April 26, 2018, PacifiCorp submitted in the instant docket a filing with updates to its standard avoided cost schedule,[17] including updates to the renewable avoided cost prices based on a proxy Wyoming wind resource to become available in 2024.[18] On the same date, PacifiCorp filed a Motion for Emergency Rate Relief, asking the Commission to issue an order: "(1) approving the concurrently filed updated avoided cost prices based on the acknowledgment of the company's 2017 Integrated Resource Plan (IRP); (2) requiring that all qualifying facilities (QFs) receive the same avoided cost price based on the assumed deferral of a new wind resource in 2021 (*i.e.*, the renewable avoided cost price stream included in the update to the avoided cost information formerly known as Schedule 37); and (3) granting the requested relief immediately, and on an interim basis pending the Commission's review of the updated avoided cost prices and resolution of the request to modify the methodology for calculating standard avoided cost prices implicated by the above requests."

In response to the 2018 Compliance Filing and Emergency Motion, several stakeholders filed comments that argued that the purchase of Oregon QF power could avoid the need for the

[15] *Id*.
[16] *Id*.
[17] *Pacific Power*, Docket No. UM 1179, Schedule 37 Avoided Cost Purchases from Qualifying Facilities - Compliance Filing (Apr. 26, 2018) (2018 Compliance Filing).
[18] 2015 Compliance Filing, Appendix 2 at 3, n.2.

proxy unit, and therefore avoid the need to construct segment D.2 to which the proxy unit would interconnect.[19] The stakeholders argued that PacifiCorp should increase Oregon avoided cost rates because sufficient evidence had been presented to rebut the Commission's presumption against inclusion of avoided transmission costs for on-system proxy resources.[20] On May 15, 2018, Commission Staff issued a report recommending that PacifiCorp file to revise its renewable avoided cost prices to include the costs of segment D.2 on the theory that the transmission line "enables the interconnection of the wind resources in PacifiCorp's IRP with PacifiCorp's transmission system."[21]

On May 18, 2018, PacifiCorp filed comments responding to Staff's report and a Reply in Support of the Motion for Interim Relief, arguing that it would be unreasonable to include the cost of segment D.2 in avoided cost rates because the transmission project was not actually avoidable.[22]

III. ARGUMENT

Consistent with federal guidance establishing a high bar for including unique avoided cost rate "adders," such as an adder reflecting avoided transmission costs, the Commission created a presumption *against* including on-system proxy resource transmission costs in avoided cost rates unless it could be overcome by "compelling" evidence.[23] Staff and parties representing QF interests who seek to overcome this presumption bear the burden to demonstrate with "factual and not anecdotal"[24] evidence that there are transmission costs associated with the

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[19] *See In the Matter of PacifiCorp, dba Pacific Power*, Application to Update Schedule 37, Docket No. UM 1729, Comments of the Community Renewable Energy Association and The Renewable Energy Coalition (May 11, 2018).
[20] *Id*.
[21] *Public Utility Commission of Oregon*, Docket No. UM 1729, Staff Report (May 22, 2018).
[22] *Pacific Power*, Docket No. UM 1729, PacifiCorp's Comments to Staff's Report on Annual and Post-IRP Avoided Cost Updates at 1 (May 18, 2018).
[23] Order No. 16-174 at p.8.
[24] *Id*.

proxy resource that are both *avoidable* and *avoided* in order to prevail. Neither test is met in this proceeding because segment D.2 is not avoidable, nor will it actually be avoided by PacifiCorp's purchase of Oregon QF power.

A. Regulatory Framework Applicable to Special Avoided Cost Rate "Adders"

FERC regulations enumerate several categories of costs that states may consider in setting QF rates, none of which include capital costs of transmission.[25] While FERC gives states some latitude in implementing those regulations, FERC case law sets a high bar for any novel "adders" or "bonuses" to avoided costs rates. In contrast to base avoided cost rates, which rely to some degree on approximation and assumptions regarding the potential for QF power to avoid costs associated with energy and capacity needed to serve load,[26] the costs identified in adders

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[25] 18 C.F.R. § 292.304(e) ("Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account: (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data; (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including: (i) The ability of the utility to dispatch the qualifying facility; (ii) The expected or demonstrated reliability of the qualifying facility; (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance; (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities; (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation; (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.").

[26] In its landmark PURPA order, Order No. 69, FERC reviewed the circumstances under which it would be appropriate for QFs to receive a capacity payment (*i.e.*, a core component of traditional avoided cost rates), as well as the difficulties presented by actually calculating such a payment. FERC noted, for example, that capacity payments can only be required when the availability of capacity from a QF "actually permits the purchasing utility to reduce its need to provide capacity by deferring the construction of a new plant or commitments to firm power purchase contracts," but nevertheless recognized that "the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise, and is one which, by definition, is based on estimation and forecasting of future occurrences." *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 59-66 (1980). While FERC's policy does not abandon the causal nexus between actual avoidance of a capacity need and the addition of QF capacity, it leaves room for the state to allow some degree of estimation when calculating the appropriate capacity payment. As discussed in this section, this is not the case for avoided cost rate "adders."

must be real utility costs that are actually avoidable by the addition of the QF if they are to be included in QF rates.

FERC examined the concept of an avoided cost rate transmission cost adder in 2010 when it considered two petitions for declaratory order filed by the California Public Utility Commission (CPUC) and three California utilities,[27] seeking guidance on a variety of different contested issues related to the CPUC's decision to require the California utilities to offer a set price to certain combined heat and power (CHP) generating facilities.[28] As most relevant here, the CPUC established a tiered price for CHP purchases based on, among other factors, the location of the facility, *i.e.*, a price "adder" that applied when a QF sited in a transmission constrained area where more generation is needed.[29] In that case, the adder reflected the avoided cost of distribution and transmission upgrades that would otherwise be necessary to transmit additional generation to the constrained area in the absence of the QF's helpful siting choice.[30]

In July 2010, FERC issued an order declining to address the specifics of the CPUC's rate, including the location "bonus" or "adder," but making the general finding that the CPUC's program was not preempted by PURPA as long as the rate established by the CPUC did not exceed the avoided cost of the purchasing utility, consistent with PURPA, FERC's regulations, and FERC's long-standing precedent.[31] In October 2010, FERC issued a subsequent order in which it still declined to rule on the CPUC's specific rate, but did discuss the conceptual framework of the CPUC's location "adder" with more specificity, emphasizing the importance of

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[27] Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.
[28] *See generally* FERC Dockets EL10-64 and EL10-66. At various points throughout the UM 1610 and UM 1729 proceedings, parties have pointed to certain orders in these FERC dockets as authority for the proposition that FERC has expressed blanket support for inclusion of transmission costs in avoided cost rates. As discussed in more detail in this brief, that is an oversimplified, inaccurate, and misleading characterization of FERC's precedent.
[29] *Cal. Pub. Utils.*, 133 FERC ¶ 61,059 at PP 12, 21, 31 (2010).
[30] *Id*.
[31] *Cal. Pub. Utils.*, 132 FERC ¶ 61,047 at PP 65-67 (2010).

the locational adder reflecting an *actual*, not *theoretical*, avoided transmission cost. FERC reviewed its precedent finding that "an avoided cost rate may not include a 'bonus' or 'adder' above the calculated full avoided cost rate of the purchasing utility, to provide for, for example, environmental externalities *above* avoided costs."[32] If, however, the costs at issue are "***real costs*** that would be incurred by utilities," then they may be accounted for in avoided cost rates.[33] Thus, FERC found that if the CPUC bases the "adder" on "an actual determination of the expected costs of upgrades to the distribution or transmission system that the QFs will permit the purchasing utility to avoid, such an 'adder' or 'bonus' would constitute an ***actual avoided cost determination***" and would therefore be consistent with PURPA and FERC's regulations."[34]

FERC's findings in that case are important for several reasons. As a threshold observation, the facts considered by FERC were entirely at odds with the question currently before this Commission. The CPUC's program incentivized, on a QF-by-QF basis, projects siting in well-known, transmission-constrained areas where generation was needed. Such a QF siting decision could *actually avoid* the utility's need to upgrade its transmission system to deliver additional generation to the constrained area. Thus, there was a direct nexus between the QF's siting decision and the avoided transmission cost. Here, there is no such nexus. The Oregon QFs have no electrical nexus to the D.2 segment whatsoever. The mere existence of a QF in the state of Oregon does not alleviate a Wyoming transmission constraint, nor does it reduce in any manner the transmission costs associated with segment D.2. The QFs' plea for a generically applicable price adder available to all QFs that are eligible for a standard rate is

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[32] *Cal. Pub. Utils.*, 133 FERC ¶ 61,059 at P 31, citing *Southern Cal. Edison*, 71 FERC ¶ 61,269 at 62,080 (emphasis added).
[33] *Id*. (emphasis added).
[34] *Id*. (emphasis added). In January 2011, FERC issued a final order in this proceeding denying rehearing and reemphasizing, as most relevant here, the core PURPA principle of customer indifference, which, when applied to avoided cost rates, mandates that rates cannot exceed the cost of energy that a utility would itself generate or purchase **but for** the QF purchase. *Cal. Pub. Utils.*, 134 FERC ¶ 61,044 at P 32 (2011).

instead based on a highly tenuous, theoretical justification that falls well short of this Commission's compelling evidence standard and violates PURPA customer indifference principles.

With respect to compelling evidence, FERC's findings reflect a core principle of ensuring unique avoided cost rate adders relate to actual, not theoretical, costs—a principle this Commission reflected in its own policies when it created a rebuttable presumption against including avoided transmission costs for on-system resources that can only be overcome by "compelling" and "not anecdotal" evidence that transmission costs are *actually* avoided. As discussed in detail in the next section, the D.2 segment is a result of PacifiCorp's transmission plan, and cannot be avoided by avoiding the proxy resource or by purchasing Oregon QF power.

B. Segment D.2 Is Not Avoidable

Throughout this proceeding there has been confusion about the Gateway West transmission project in general, the D.2 segment specifically, and whether or how it might be avoided if the proxy resource is avoided. D.2 is not avoidable because it is not caused by any single generator or group of generators. Rather, it is part of PacifiCorp's long-term transmission expansion plan that serves many purposes. To provide context for that distinction, PacifiCorp will first explain each driver of transmission upgrades under FERC's paradigm.

1. Federal Drivers of Transmission System Upgrades

a. Service Request-Driven Transmission System Upgrades

Upgrades to a utility's integrated transmission system—or "network upgrades" in FERC's open access transmission tariff (OATT) parlance—can be driven by specific requests for either transmission service (*i.e.*, delivery service) or interconnection service (*i.e.*, interconnection with a utility's transmission system). When a customer requests transmission service or interconnection service, transmission providers are obligated to perform studies to determine what, if any, transmission system network upgrades are necessary to provide the requested service. If the requested service cannot be granted without network upgrades, the transmission provider is obligated to construct them.

b. Federally Regulated Transmission Planning

In contrast to network upgrades driven by specific service requests, network upgrades can also be planned by the transmission provider as part of a local or regional transmission plan. This type of network upgrade is not tied to or caused by a specific request for service. Rather, it is identified in planning studies as necessary to maintain reliability, accommodate load growth, or satisfy other federal planning criteria.[35] For example, Attachment K of PacifiCorp's OATT contains its FERC-approved transmission planning principles and identifies the following criteria relevant to its local transmission plan (*i.e.*, the plan for PacifiCorp's balancing authority area not planned in conjunction with other regional transmission providers):

> …investments to the Transmission System and Demand Resources necessary to reliably satisfy, over the planning horizon, Network Customers' resource and load growth expectations for designated Network Load and Network Resource additions; Transmission Provider's resource and load growth expectations for Native Load Customers; Transmission Provider's transmission obligation for Public Policy Requirements; Transmission Provider's obligations pursuant to grandfathered, non-OATT agreements; and Transmission Provider's Point-to-Point Transmission Service Customers' projected service needs including obligations for rollover rights.

2. Applying Federal Principles to Segment D.2

Understanding these various FERC-endorsed drivers of transmission upgrades helps put the D.2 segment into context and provides a basis for understanding why this transmission

[35] FERC's transmission planning requirements are primarily set forth in two landmark orders. *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 (2007); and *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011).

project is not actually avoidable, and therefore should not be part of avoided cost rates. In short, D.2 is not *caused* by any single generator or group of generators, but rather is part of PacifiCorp's long-term transmission expansion plan that serves many purposes.

PacifiCorp's long-term, federal transmission planning process has long identified the construction and benefits of Gateway West (including segment D.2) beyond just additional generator interconnection capability, including increased reliability, congestion relief, and reduction of capacity and energy losses.[36] Indeed, PacifiCorp has been pursuing permitting for the construction of Gateway West since 2007[37]—long before PacifiCorp's recent Energy Vision 2020 proposal to accelerate the construction of segment D.2 from 2024 to 2020. As PacifiCorp recently testified in Utah:

> [T]he Aeolus-to-Bridger/Anticline line is necessary to relieve existing congestion on the system and…the North American Electric Reliability Corporation's and Western Electricity Coordinating Council's standards and criteria influenced the need for the Aeolus-to-Bridger/Anticline line. The Company made it clear that the Aeolus-to-Bridger/Anticline line has been an integral component of the long-term transmission plan for the region long before the Wind Projects were contemplated.[38]

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[36] *Pacific Power*, Docket No. UM 1729, PacifiCorp's Comments to Staff's Report on Annual and Post-IRP Avoided Cost Updates at 2 (May 18, 2018); Docket No. LC 67, 2017 Integrated Resource Plan at 63 (Apr. 4, 2017) ("Other customer benefits of the new transmission segment include increased reliability of the transmission system, congestion relief, reduction of capacity and energy losses on the transmission system, and greater flexibility managing existing generation resources. Reliability will be augmented with the addition of the new transmission segment, which will provide support to the underlying 230 kV system during outages. Most of these outages result in a deration of TOT 4A transfer capacity and some outage scenarios require significant generation curtailment. The new 500 kV transmission segment will significantly reduce, if not eliminate, many of the impacts caused by the 230 kV outages. Increased energy imbalance market (EIM) and transmission wheeling opportunities under the OATT will also result from the additional system capacity. Capacity and energy losses on the transmission system are reduced with the new transmission segment, which has the potential to provide significant monetary savings over time.").

[37] As the Company stated in Utah: "The Aeolus-to-Bridger/Anticline transmission line has been part of the Company's long-term transmission plan since 2007 and provides substantial immediate benefits with or without the Wind Projects (Ekola Flats, TB Flats I and II, and Cedar Springs)." *Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities*, Public Service Commission of Utah, Docket 17-035-40, Redacted Surrebuttal Testimony of Rick A. Vail at 1 (May 15, 2018).

[38] *Id.* at 4.

Importantly, this means that segment D.2 will be constructed with or without the new Wyoming wind projects, and it will most certainly be built with or without additional QFs siting in Oregon. In other words, no amount of QFs located in Oregon could actually avoid—in whole or in part—the cost of this new transmission line, and the presumption that there are no avoided transmission costs associated with PacifiCorp's on-system proxy resource has not been rebutted.

C. Arguments in this Docket To-Date Offer Multiple Versions of a Standard, All of Which are Wrong

The Commission Staff and stakeholders representing QF interests appear to assume an oversimplified and inaccurate causal relationship between the Wyoming wind generators (and, thus, the proxy resource) and segment D.2. For example, they suggest that because segment D.2 is "associated with" the renewable proxy resource, the cost of segment D.2 can be avoided if the proxy resource is avoided.[39] The Staff Report furthers states that "[b]ecause PacifiCorp would not build the avoided wind resource without new transmission, the renewable proxy resource should include transmission costs…."[40] Stakeholders representing QF interests assume that "the combined costs of the new wind plus the required transmission" should be reflected in the avoided cost rate and argue that the "planned" transmission line is "only economic if tied to the

[39] Docket No. UM 1729, Public Utility Commission of Oregon Staff Report, 5 (May 22, 2018) (Staff Report); Docket No. UM 1729, COALITION, CREA, and NIPPC's Comments on Staff Report, 3 (Mar. 23, 2018) (QF Parties' Comments).
[40] *Id*. at 5.

acquisition of new wind generation in Wyoming," and therefore, the transmission costs should be included in the avoided cost rate that the planned transmission line.[41]

These comments and false standards unnecessarily muddy the waters. Segment D.2 will create additional interconnection capability, which means additional generators will be able to secure interconnection to PacifiCorp's system in Wyoming. These additional generators impact the economics of constructing segment D.2. This physical and economic relationship between segment D.2 and the generators should not, however, be misinterpreted as a *causal* relationship. Segment D.2 is not a "but for" result of new interconnection requests (or the proxy resource) in Wyoming. Rather, PacifiCorp is constructing segment D.2 in accordance with its long-standing, federally regulated, transmission expansion plan because segment D.2 provides significant reliability and other system benefits far beyond just increased interconnection. This means the construction of segment D.2 is not avoidable even in the absence of the Wyoming generators or proxy resource, much less as a result of PacifiCorp's purchase of any amount of power from QFs in Oregon. As a result, including the costs of segment D.2 in avoided cost rates would violate: (1) FERC and this Commission's policies because no real transmission costs will *actually* be avoided by the QF purchases, so there is no justification for a special avoided cost rate adder; and (2) PURPA's customer indifference standard because PacifiCorp's customers would be paying increased rates for QF power based on the theoretical assumption that a line will be avoided, when in fact its construction is not avoidable.

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[41] QF Parties' Comments at 3. Finally, any discussion of "adders" to QF rates must also be accompanied by a discussion of "subtractors." Assuming for the sake of argument that a proxy resource's transmission costs were actually avoidable and eligible for inclusion in avoided cost prices, a related analysis would have to be conducted to determine with equal precision what additional transmission costs were caused by the QFs (*e.g.*, associated with the utility's transmission service arrangements to deliver the QF output to load) that might have to be subtracted from QF rates. PacifiCorp is not suggesting the Commission go down this road, only that the QF theory seeking cost adders is as incomplete as it is unsupported.

IV. CONCLUSION

There is no basis in fact or law to support the inclusion of the cost of segment D.2 in QF avoided cost rates because segment D.2 is not avoidable, and it will not actually be avoided by the purchase of Oregon QF power. The high bar this Commission established for rebutting the presumption against the inclusion of avoided transmission costs by identifying real, not theoretical, transmission costs cannot be satisfied with regard to the D.2 transmission project. If the Commission were to grant this request for increased avoided cost rates without compelling evidence of actual avoided transmission costs, customer costs will increase and no transmission will be avoided. Such a decision would run afoul of this Commission's prior decisions in this area, violate PURPA's bedrock principle of customer indifference, and unnecessarily and inappropriately increase the energy costs of Oregon customers.

Respectfully submitted this 12th day of July, 2018.

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