CASE: UM 1802
WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Reply Testimony

May 5, 2017

Q. Please state your name, occupation, and business address.

A. My name is Brittany Andrus. I am a senior utility analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit Staff/101.

Q. What is the purpose of your testimony?

A. Staff provides testimony on whether PacifiCorp should offer nonstandard[1] avoided cost price streams to Qualifying Facilities (QF) that reflect the value of the renewable characteristics of those QF projects (Issue 1). Staff also addresses the question of how the nonstandard avoided costs for renewable QFs should be calculated (Issue 2). Finally, Staff responds to the issue of whether the market price should serve as the floor for avoided cost prices (Issue 3).

Q. Please summarize the Staff position.

A. First, on the question of whether PacifiCorp should offer nonstandard renewable avoided cost prices to renewable QFs, Staff believes that for policy reasons previously articulated by the Commission, PacifiCorp, as an Oregon regulated utility with an obligation to acquire renewable resources under state's Renewable Portfolio Standard (RPS), should be required to offer renewable

[1] "Nonstandard" refers to a category of QFs ineligible for standard avoided cost prices. Nonstandard prices are available to QFs with megawatt (MW) capacities that exceed specific "eligibility caps." For PacifiCorp, the standard price eligibility cap is 3 MW for solar QFs, and 10 MW for other QF types.

avoided cost prices to QFs that reflect the avoided costs of acquiring an RPS compliant resource.

Second, regarding the methodology for deriving the nonstandard renewable avoided cost prices, Staff rejects certain components of the proposed approach in the Company's opening testimony, and sets forth two alternatives.

Finally, Staff supports the application of market prices as the floor for nonstandard avoided cost prices.

ISSUE 1: WHETHER PACIFICORP'S NONSTANDARD AVOIDED COST PRICING SHOULD INCLUDE A RENEWABLE PRICE OPTION

Q. Please describe the Commission's policy regarding renewable avoided cost prices in Oregon.

A. In Order No. 11-505, the Commission addressed whether to require utilities to offer a renewable avoided cost price stream to renewable QFs. The Commission concluded the two utilities subject to the RPS should do so. The Commission decided that Portland General Electric Company (PGE) and PacifiCorp must offer renewable QFs two avoided cost price streams, finding that this is consistent with the Federal Energy Regulatory Commission's (FERC) ruling clarifying the right of the states to determine the avoided cost associated with utility purchases of energy from generators with certain characteristics.[2] The Commission noted that "[r]enewable QFs willing to sell their output and cede their RECs to the utility allow the utility to avoid building (or buying) renewable generation to meet their RPS requirements[,]" and that "[t]hese QFs should be offered an avoided cost stream that reflects the costs that utility will avoid."[3]

Q. What parameters did the Commission establish for renewable avoided costs?

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[2] *Investigation Into Resource Sufficiency Pursuant to Order No. 06-538* (Docket No. UM 1396); Order No. 11-505 at 9.
[3] *Id* at 9.

A. First, the renewable avoided cost price stream distinguishes between periods of resource sufficiency and deficiency, as is the practice for nonrenewable avoided cost prices. QFs are paid market prices during the sufficiency period. Second, the deferrable proxy resource under the renewable avoided cost price stream is the next avoidable *renewable* resource identified in the utility's acknowledged integrated resource plan (IRP) rather than the combined cycle combustion turbine that is used for the nonrenewable prices. The Commission has not addressed these requirements since the issuance of Order No. 11-505.

Q. Please explain the differences between standard and nonstandard avoided costs.

A. Standard prices are available to QFs with megawatt (MW) capacities that do not exceed specific "eligibility caps." Those prices are based on a proxy resource based on the utility's next avoidable resource. For PacifiCorp, the standard price eligibility cap is 3 MW for solar and 10 MW for other QF types.[4] "Nonstandard" pricing is available to all QFs and is the only option for QFs that are ineligible for standard avoided cost prices. Nonstandard prices are based on the characteristics of the selling QF, rather than a proxy resource.

Q. Does PacifiCorp offer renewable standard avoided cost prices to QFs?

[4] The Commission reduced PacifiCorp's standard price eligibility cap for solar QF projects from ten MW to three MW in Order No. 16-130; Docket No. UM 1734; March 29, 2016.

A. Yes. PacifiCorp offers a schedule of standard renewable prices, based on an avoided wind resource, with a deficiency period beginning in 2028.[5]

Q. Does PacifiCorp offer nonstandard renewable prices to QFs?

A. Following Order No. 11-505, PacifiCorp offered both standard and nonstandard renewable prices. PacifiCorp discontinued offering a nonstandard renewable avoided cost price stream after the Commission authorized PacifiCorp to use its Partial Displacement Differential Revenue Requirement (PDDRR) methodology to determine avoided cost prices for the non-standard avoided cost price stream at the conclusion of Phase II of Docket No. UM 1610. [6]

Q. Does Staff believe that the Commission's decision to allow PacifiCorp to use its PDDRR method to calculate non-standard avoided cost prices eliminates the requirement that PacifiCorp offer nonstandard renewable and nonstandard nonrenewable avoided cost price streams?

A. No. While PacifiCorp's testimony reflects that it is willing to offer nonstandard renewable avoided cost prices in limited circumstances, this limited offer is not sufficient to comply with the Commission's previous determination in Order No. 11-505.

Q. How did PacifiCorp calculate nonstandard avoided cost prices prior to Order No. 16-117 allowing it to use the PDDRR method?

A. PacifiCorp followed the methodology set out in Order No. 07-360. In

[5] The Commission directed PacifiCorp to use a deficiency period beginning in 2028, despite the lack of a deferrable renewable resource in the acknowledged 2015 IRP. Intervening events, including the passage of Senate Bill 1547 in 2015 and PacifiCorp's release of a Request for Proposals (RFP), informed this decision; Order No. 16-307, Docket UM 1729(1); August 18, 2016.

[6] *Investigation into Qualifying Facility Contracting and Pricing* (Docket No. UM 1610); Order No. 16-174.

Order No. 07-360 the Commission adopted Large QF Guidelines. This order defines, among other things, the Commission's approach to adjusting avoided cost prices to account for a specific QF's characteristics. These adjustments are based on factors that FERC requires avoided cost calculations to take into account "to the extent practicable."[7]

Q. Did Staff support or oppose the use of the PDDRR method?

A. Staff supported the use of PDDRR believing it could increase the ability of PacifiCorp to adjust avoided cost prices to take into account the characteristics of the selling utility.[8]

Q. When did PacifiCorp's use of the PDDRR method take effect?

PacifiCorp filed an update to its Standard Avoided Cost Prices (previously Schedule 37) and Nonstandard Avoided Cost Prices (previously Schedule 38) in compliance with Order 16-174. The Standard Avoided Cost Prices were

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[7] *CFR 292.304(e):* "(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;…"

[8] Docket No. UM 1610 Phase II Staff/500, Andrus/34-35.

approved at the October 25, 2016 public meeting, and the Commission deferred a decision on the Nonstandard Avoided Cost Prices. Stakeholders and the Company submitted comments on the proposed pricing, included in the Staff Report for the November 8, 2016 public meeting. Because the filing met the requirements of Order No. 16-174, which did not specifically direct a PDDRR methodology for renewable nonstandard QF prices, the Commission approved the use of the PDDRR and directed that an expedited investigation be opened "to examine whether PacifiCorp's nonstandard avoided cost pricing should include a renewable price option, and if so, how that renewable price option should be calculated."[9]

Q. Why does Staff believe that the renewable PDDRR, or another method of calculating a renewable avoided cost, should be available to QFs ineligible for standard pricing?

A. When the Commission directed that renewable avoided cost prices should be offered to QFs in Order No. 11-505, it did not make a distinction between standard and nonstandard pricing. That order directed, in part,

> • Separate renewable avoided cost rates should be adopted for Portland General Electric Company (PGE) and PacifiCorp, dba Pacific Power (Pacific Power). Because Idaho Power Company (Idaho Power) is not fully subject to the Oregon renewable portfolio standard (RPS), no renewable resources avoided cost rate should be adopted for that utility at this time;
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> • During periods of renewable resource sufficiency, the rate will be based on market prices. During periods of renewable resource deficiency, the rate will be based on the renewable avoided cost of the next utility scale renewable resource acquisition in that utility's IRP. The renewable resource QF will

[9] Docket No. UM 1610, Order No. 16-429; November 9, 2016.

> keep all associated Renewable Energy Certificates (RECs) during periods of renewable resource sufficiency, but will transfer those RECs to the purchasing utility during periods of renewable resource deficiency;
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> • The IRP Action Plan should be used to identify when a renewable resource acquisition could be avoided. Out-of-state renewable portfolio standards should not be used to determine when a renewable resource can be avoided;
>
> • A renewable QF should have the option of choosing among the renewable avoided cost stream and the standard avoided cost stream…

Staff maintains its position stated in the November 8, 2016 Staff Report that nothing in Order No. 16-174 indicates that the Commission intended to rescind the requirement imposed under Order No. 11-505.

ISSUE 2: METHODOLOGY FOR DERIVING THE NONSTANDARD RENEWABLE AVOIDED COST PRICES

Q. Has PacifiCorp maintained its position that it should not be required to offer renewable nonstandard prices?

A. Not entirely. PacifiCorp is now proposing to offer renewable avoided cost prices, but only for a subset of the QFs that are ineligible for standard prices. In opening testimony, PacifiCorp states,

> The Company agrees that renewable avoided cost pricing should be available for nonstandard renewable QFs when: (1) the preferred portfolio in the Company's most recent Integrated Resource Plan (IRP) identifies the need for a renewable resource of the same type; and (2) the identified need exists during the term of the QF's PPA. Renewable avoided cost prices for non-standard QFs would be calculated using limited modifications to the Partial Displacement Differential Revenue Requirement (PDDRR) methodology recently approved by the Commission.[10]

Q. Under this approach, which QFs would be ineligible for nonstandard renewable prices?

A. The key phrase is "a renewable resource of the same type." In PacifiCorp's recently-filed 2017 IRP, the next avoided renewable resource is a wind project online in 2021. By proposing this restriction, PacifiCorp would deny the opportunity for nonstandard renewable prices for any QF technology other than wind: solar, hydro and all other non-wind technologies.

Q. On what basis does PacifiCorp support this technology limit?

A. PacifiCorp claims that "Because wind and solar have different seasonal and hourly shapes, this could rapidly create an imbalance. Deferring a smaller

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[10] PAC/100, MacNeil/2.

quantity of a thermal resource with little seasonality would create less of a potential mismatch."[11]

However, earlier the testimony, witness MacNeil states that "The same reasons that supported use of PDDRR to defer non-renewable resources apply to renewable resources, and it can be easily tailored to reflect deferral of various resource types."[12] These conflicting statements do not appear to be resolved in PacifiCorp's opening testimony.

Q. Other than the question of whether to apply the PDDRR to QFs of a different type than the next renewable resource in the IRP, does Staff differ with PacifiCorp on the application of the PDDRR method?

A. Yes. PacifiCorp proposes the following:

> QFs partially displace the next major thermal resource in the IRP based on their capacity contribution. The Company proposes that under a renewable PDDRR, renewable QFs would instead defer the next major renewable resource of the same type in the IRP preferred portfolio, again based on equivalent capacity contributions.[13]

Thermal resources planned for in the IRP are intended to serve load, but renewable resources planned for in the IRP are intended to meet the utility's obligation under the RPS. A MWh of renewable solar provides the same RPS value as a MWh of renewable wind. A renewable QF defers the next renewable resource in the IRP preferred portfolio, with no capacity equivalence constraint.

[11] PAC/100, MacNeil 6.
[12] Id. p. 3.
[13] Id. p. 3-4.

Q. Is there a precedent for comparing wind capacity to capacity of a different technology?

A. Yes. Standard prices, both nonrenewable and renewable, are based on adjustments to an avoided IRP resource to account for the different capacity contribution of the QF type.

Q. How does this capacity adjustment impact avoided cost prices?

A. Tables 1 and 2 below show how PacifiCorp's current standard avoided cost prices differ by technology for both nonrenewable and renewable QFs. Nonrenewable prices, Table 1, include an adjustment for the capacity of the QF relative to the capacity of the avoided *nonrenewable* resource (CCCT). The capacity value of the QF is paid during on-peak hours[14] only, i.e., over the course of a year, the total dollar value of the QF capacity is paid on a per-MWh basis based on the expected generation pattern.

So, the baseload QF receiving nonrenewable pricing is compensated at the cost of the avoided baseload CCCT in the IRP, which in this case is $62.80 on-peak for the energy and capacity, and $32.50 off-peak for the energy only. In contrast, the on-peak prices for the two types of solar QFs (fixed and tracking) are lower than that of a baseload QF, reflecting the relatively lower capacity value. Similarly, the wind QF receives yet a lower price, as it brings an even smaller capacity amount.

[14] Defined by the North American Electric Reliability Corporation as 6:00 a.m. to 10:00 p.m. Monday through Saturday, except certain holidays.

Table 1. Standard Nonrenewable Prices ($/MWh)

	On-Peak	Off-Peak	On-Peak	Off-Peak
	Baseload		Wind	
2028	62.80	32.50	51.80	28.40
	Fixed Solar		Tracking Solar	
2028	58.40	32.50	57.90	32.50

In the case of renewable QF standard prices, the capacity adjustments are based on the QF relative to the avoided *renewable* resource (wind). It follows that renewable QFs providing more capacity relative to wind, such as solar or baseload, receive a higher capacity payment, as shown in Table 2.[15]

Table 2. Standard Renewable Prices ($/MWh)

	On-Peak	Off-Peak	On-Peak	Off-Peak
	Baseload		Wind	
2028	102.60	66.00	75.90	61.90
	Fixed Solar		Tracking Solar	
2028	85.50	66.00	87.80	66.00

Q. How is the standard pricing method applicable to nonstandard pricing?

Nonstandard prices for a specific renewable nonstandard QF can similarly be calculated to account for the resource's capacity contribution by adjusting the IRP renewable resource to account for capacity of a specific QF. The difference between the standard and nonstandard method is that the QF

[15] Additional adjustments, e.g., for integration costs and avoided transmission, may also be incorporated into standard avoided cost prices.

resource generation output profile is specific to a particular QF rather than a generalized proxy resource, and therefore the benefit described in Staff's opening testimony in Docket No. UM 1610 Phase II is attained: "…a more accurate quantification of the impact of a QF based on its specific characteristics."[16] These characteristics need not be constrained to a specific technology.

Q. Does Staff agree with the renewable PDDRR process as described by the Company for calculating the renewable avoided cost stream?

A. To an extent. Staff agrees generally that GRID (or a similar tool) should be used to determine the value of the avoided energy created by the QF, and that the value of its avoided capacity is additional to that energy value.

Staff also agrees that the next avoided renewable resource should be used to calculate the avoided capacity.

Staff fundamentally disagrees with PacifiCorp's assertion that it would create "imbalance" and a "potential mismatch"[17] to adjust the deferred capacity value for QFs of resource types other than that of the next renewable resource in the IRP preferred portfolio.

Also, Staff disagrees that "potential QFs" should be included when running the PDDRR calculation to determine prices for a particular QF.[18] There is no certainty that all QFs requesting pricing will move to the next stage in the

[16] Docket No. UM 1610 Phase II Staff/500, Andrus/34.
[17] PAC/100, MacNeil 6.
[18] PAC/100, MacNeil/10, "Signed and potential QFs (located anywhere on PacifiCorp's system) are accounted for in the GRID model when calculating avoided costs for the next QF."

contracting process. Accordingly, Staff believes that only contractual obligations should be included, i.e., executed QF PPAs.

As to other aspects of PacifiCorp's renewable PDDRR proposal, Staff's assessment is limited to the process as explained in testimony. However, not all of the details of the methodology were presented for analysis. For example, the Company did not indicate the time period it used to test the PDDRR in the GRID modeling, nor were the various assumptions about commodity and market prices explained.

Q. What is Staff's proposal regarding operation of the PDDRR methodology?

A. The PDDRR process begins by comparing two GRID modeling runs – the first is a baseline run of the system without the additional QF and the second run is made after adding the QF to the system. When the QF is added to the second run, its energy is offered at zero cost. Also in the second run, the capacity of the Company's next planned renewable resource is reduced by the amount of capacity represented by the QF.

Q. How are the two GRID runs used?

A. The GRID runs will produce two useful outputs – the amount of energy generated by the QF and the difference in system cost resulting from the addition of the QF. Because the QF provides zero-cost energy, the second GRID run will reflect a lower cost which is a direct result of burning less traditional fuel on the system – this represents one part of the avoided cost.

There is a second potential cost savings due to the partial capacity reduction of the planned resource.

Q. What is the avoided cost of this capacity reduction?

A. The capacity cost avoided by the utility is equal to the cost of the portion of the renewable resource that is avoided by the utility. This is a pure capital cost (since there are no fuel related costs) and can readily be calculated as the displaced portion of the planned plant capacity. In the easiest example, if the utility is planning for a 100 MW wind plant, a 10 MW wind QF with similar operating characteristics will reduce that need by 10 MW, and the planned resource now is only 90 MW.

Q. Does the QF necessarily need to be a wind plant to avoid capacity if the next planned renewable resource is wind?

A. No. The Company chose the planned renewable resource because the Company's analysis indicated it would be the least cost, least risk path to RPS compliance. However, any technology that is eligible under the RPS can fill this need for compliance. The Company's RPS obligation is expressed in annual energy terms, in MWhs. Any eligible technology that produces the same amount of annual energy fulfills this need.

Q. How does this fact affect the PDDRR methodology?

A. Although the PDDRR methodology identifies a specific, physical wind plant for "partial displacement" of capacity, there is no requirement that the QF be wind. The only requirement is that the QF produce RPS eligible energy.

Q. Please provide an illustrative example.

A. As I pointed out previously in my testimony, a wind QF will reduce the planned need for wind capacity on a one-for-one basis as long as capacity factors are similar. The reason for this is that the annual energy production from two plants with the same capacity factor is essentially equal. If the QF is a solar plant instead of a wind plant, the QF will displace an amount of planned capacity that produces the same annual energy output as the solar QF. That is, if the solar QF produces 100,000 MWh in a year it will displace an amount of planned capacity that also produces 100,000 MWh per year. However, because the technologies are different, it is likely that a different (nameplate) capacity rating in MW will also be different between the QF and the planned wind resource – that is, 1 MW of solar does NOT produce the same amount of energy as 1 MW of wind. In our example, based on typical capacity factors,[19] it takes about 45 MW of solar to produce the 100,000 MWh in a year ((100,000 MWh/8760 hours in a year) divided by solar capacity factor (25 percent)). However, a wind resource of only 33 MW is needed to produce the same amount of energy. So, it is clear that in this example, 45 MW of a solar QF resource will displace about 33 MW of the planned wind resource. The avoided capacity cost is then the cost associated with 33 MW of planned wind.

Q. Does Staff believe this is the only appropriate way to apply the PDDRR methodology for nonstandard renewable QF pricing?

[19] Approximately 25 percent for solar and 35 percent for wind.

A. Staff does not assume all the answers are to be found in the method described above. A more in-depth review is certainly required to arrive at a clearly defined methodology. But the core of the approach Staff defines in this Issue 2 testimony should be included.

Q. Does Staff propose any alternative to the method described above?

Yes. If the GRID/PDDRR method described above is not adopted, Staff supports reverting to the method adopted under Order No. 07-360 for pricing nonstandard QFs, both renewable and nonrenewable: adjusting standard nonrenewable avoided cost prices to account for a specific QF's characteristics, based on the factors prescribed by FERC, as described in my earlier testimony.

<u>ISSUE 3</u>: WHETHER THE MARKET PRICE SHOULD SERVE AS THE FLOOR FOR NONSTANDARD AVOIDED COST PRICES

Q. What did the Commission decide regarding the use of a market price floor issue for nonstandard prices?

A. In Order No. 16-174 the Commission simultaneously authorized the use of PDDRR, and "set the floor for non-standard avoided cost prices at the wholesale power price forecast that is used to set sufficiency period avoided cost prices in standard QF contracts."[20]

Subsequently, the Commission reaffirmed this decision in Order No. 16-337, stating: "We reaffirm that we find the market price to be the appropriate floor for the minimum avoided cost rate paid during a sufficiency period, even if the incremental cost of generation is lower than the market price because absent transmission constraints, a utility may sell the QF generation on the market."[21] Thus, the Commission has ordered and affirmed that market price is an appropriate floor during the sufficiency period "absent transmission constraints."

Q. Under what circumstances should the market price floor be reexamined?

A. The Commission's orders state that when transmission constraints inhibit the ability of the QF energy and displaced thermal power to get to market, then the market price floor may be reconsidered. Specifically, the Commission has asked to be "notified" when this occurs. Staff recommends that the

[20] Order No. 16-174 at 23.
[21] Order No. 16-337 at 6.

Commission, upon such notification, conduct a fact-finding review followed by a decision on whether or not to eliminate market floor pricing after a finding of actual constraint.

Q. Is now the appropriate time to reexamine the market price floor?

A. No. Staff comes to this conclusion for several reasons. First, in PacifiCorp's recently filed IRP, the company makes no reference to a current or pending issue associated with QF related transmission constraints. Transmission constraints that affect the ability of the Company to sell current or anticipated QF or thermal power into market represent major, near term exigencies that would rise to the level of IRP concerns. Second, PacifiCorp recently requested that the Commission close Docket No. UM1 610, in part justifying this decision because anticipated transmission constraints associated with moving QF production out of load pockets has not materialized.[22] Though Docket No. UM 1610 examined the transmission of QF production to customer load, not market, PacifiCorp's new position in that case still is indicative of a situation where anticipated transmission constraints have not materialized. Finally, lack of available transmission to market for a particular QF or for thermal resources is a specifically verifiable issue. If it is asserted or estimated that new QF development will cause transmission constraints, that question can be brought to the Commission in the context of the development in question.

[22] PacifiCorp's Motion to Close Docket No. UM 1610, March 15, 2017, at 5.

Q. Do the testimony or data request responses suggest now is the time to open a factual inquiry into whether or not transmission constraints due to QF's are present or likely in the near future?

A. No. The assertion of thermal back down in testimony is built on PDDRR and GRID runs with inappropriate assumptions. These runs assumed 692 MW of new QFs, including 431 MW of QFs that have requested pricing, and the assumption that all 261 MW of QF resource with executed contracts ("pending QFs") will be built.[23] These assumptions are not reasonable. There is no guarantee that either pending QFs or QF projects that have requested pricing will be constructed. In particular, including the 431 MW of projects requesting pricing is highly speculative.

Q. Does PacifiCorp include QFs that have requested pricing in its IRP process?

A. No. For the purposes of IRP planning, only QFs with executed agreements at the time of assumption development are permitted to be part of the analysis.[24] Inclusion of the 431 MW of QF resources with pricing requests is not consistent with PacifiCorp's own forecasting.

Q. How would using IRP or the executed 261 MW of pending QFs as the development assumption in the PDDRR and GRID analysis affect the results?

[23] PacifiCorp response to Staff data request 10.
[24] PacifiCorp 2017 IRP, Volume II, Appendix B, p. 35.

A. Remaining consistent with the IRP standard would reduce the amount of QF development in the PDDRR and GRID analysis provided in testimony by more than 62 percent.

Q. Is utilizing a QF development assumption different from the IRP in the context of this proceeding justifiable?

A. No. Including the 431 MW of QF proposals that have requested pricing in the context of PacifiCorp's testimony PDDRR and GRID runs demonstrates that the analysis is inherently flawed. In the IRP, PacifiCorp avoids analysis of hypothetical QF resources by assuming that executed qualifying contracts at the time modeling assumptions are locked down are the only contracts considered in the resource mix. It is reasonable to presume that QF development assumptions will be consistent across the Company's dockets; the same development assumptions used in the 2017 IRP should be applied in this investigation.

Q. Are there other reasons the testimony or data request responses are not compelling?

A. Yes. The model runs have not included the effect of incrementally available third party transmission. This is an important oversight, especially when considering the Company's position in Docket No. UM 1610. In that case, PacifiCorp has agreed to procure on behalf of QFs needed incremental third party transmission.[25] Accordingly, no analysis can be considered complete without taking this available transmission into account. Again, this is a

[25] PacifiCorp's Reply in Support of Motion to Close Docket, April, 6 2017 p. 4.

factually verifiable question that must be examined as part of any future reexamination of the market price floor. Also, if at the time of the asserted transmission constraint there are thermal sales on the system, any back down could be economic and not constraint-related. The Commission has determined that that only a transmission constraint may trigger an elimination of the market floor.

Q. Has PacifiCorp demonstrated a transmission constraint associated with QFs and access to market?

A. No. In no reasonable QF development assumption scenario has a get-to-market transmission constraint been demonstrated.

Q. How do you recommend this issue be addressed in the future?

A. Consistent with the several Commission orders on this issue, only when a QF cannot reach a market hub due to transmission constraints and at the same time, thermal resources that would otherwise be used to serve load displaced by the QF cannot reach a market hub due to transmission constraints, should the market floor be lifted. This is a fact-based question, and should center around specific development proposals, not on modeling assumptions that are unlikely to occur in the near term. If an individual, proposed QF under a PDDRR and GRID run with reasonable and defensible assumptions is shown to cause a transmission constraint for both the QF and displaced thermal resource, it would be reasonable for PacifiCorp to request a fact-finding docket be opened to review those anticipated constraints. At that time, steps could be taken to amend or eliminate the market price floor for that QF and for future QFs located within the constrained area, until circumstances change. However, if the modeled constraint is highly speculative, and based on indefensible assumptions, then all development occurring prior to the actual incidence of the constraint would receive a payment less than the true avoided cost because those projects actually would have access to market but would be paid as though they did not. Such a result is not consistent with PURPA requirements or the operative Commission orders on this issue. At the very least, in order for an argument asserting a transmission constraint to be credible, QF development assumptions must be consistent with those made in the IRP; and the availability of incremental third party transmission resources must be examined.

Q. Does this conclude your testimony?

A. Yes.

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WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

May 5, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME:	Brittany Andrus
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE Suite 100 Salem, Oregon, 97301-3612
EDUCATION:	M.B.A. Portland State University, Portland, Oregon B.A. English Michigan State University, East Lansing, Michigan
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission since 2011. My current responsibilities include research, analysis and technical support for electric company proceedings, with an emphasis on resource planning, power costs, and qualifying facilities under PURPA. I was previously employed for 17 years by the Bonneville Power Administration, a wholesale power marketing agency within the federal Department of Energy. My duties included energy efficiency planning and program management, long term load and revenue forecasting, long term power sales contracts, rate impact analysis, short term load forecasting, power and transmission scheduling, and management of load forecasting data and processes.