Docket No. UM 1802
Exhibit PAC/300
Witness: Daniel MacNeil

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

PACIFICORP

July 2017 Opening Testimony of Daniel MacNeil

July 2017

JULY 2017 OPENING TESTIMONY OF DANIEL MACNEIL

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/301 –Confidential GRID Model Topology with Transfer Rights

Exhibit PAC/302 –Oregon Non-Standard Avoided Cost Rates Business Practices

Q. Are you the same Daniel MacNeil who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power?

A. Yes.

PURPOSE AND SUMMARY

Q. What is the purpose of this testimony?

A. This opening testimony, filed July 21, 2017, (July 2017 opening testimony) responds to testimony regarding whether PacifiCorp should offer a non-standard renewable avoided cost price stream, and if so, how that price stream should be calculated. Specifically, I respond to the testimony presented by:

- Ms. Brittany Andrus on behalf of Public Utility Commission of Oregon (Commission) Staff (Staff/100);
- Mr. Brad Mullins on behalf of the Industrial Customers of Northwest Utilities (ICNU) (ICNU/100);
- Mr. Brian Skeahan on behalf of the Community Renewable Energy Association (CREA) (CREA/100);
- Mr. John Lowe on behalf of the Renewable Energy Coalition (the Coalition) (REC/100);
- Mr. Kevin Higgins on behalf of the Coalition and CREA (the Joint Parties) (REC-CREA/100); and
- Ms. Diane Broad on behalf of the Oregon Department of Energy (ODOE) (ODOE/100).

As part of my response to parties' testimony, I also re-evaluate how cost-effective renewable resources identified in an integrated resource plan (IRP) should be considered when developing renewable non-standard avoided cost pricing. The policy basis for this proposal is set forth in the testimony of Ms. Etta Lockey.

Q. Please summarize your opening testimony filed on January 27, 2017.

A. My opening testimony, filed on January 27, 2017, (January 2017 opening testimony) proposed a renewable partial displacement differential revenue requirement (PDDRR) methodology based on deferral of renewable resources identified in PacifiCorp's IRP preferred portfolio. Parties raised concerns that not all eligible renewable resources would receive a renewable pricing option under my proposed methodology.

Q. How has PacifiCorp's proposal changed between your January 2017 opening testimony and July 2017 opening testimony?

A. My January 2017 opening testimony proposed two avoided cost price streams—a renewable price based on the deferral of a like renewable resource and a non-renewable price stream based on deferral of a non-renewable resource. That approach, however, did not accurately reflect the narrow circumstances under which the Commission has indicated that a qualifying facility (QF) is entitled to a renewable price stream.

I am familiar with Commission Order No. 11-505, and I understand that the Commission determined that a renewable price stream is available when a QF allows a utility to defer building or buying a renewable resource needed to meet renewable portfolio standard (RPS) compliance obligations. Under my initial proposal, a QF would be entitled to renewable pricing even if it did not allow PacifiCorp to defer RPS compliance costs—a result that proposal is inconsistent with Commission policy.

Consistent with Order No. 11-505, my revised proposal recognizes that the renewable price stream should fundamentally be tied to avoided Oregon RPS compliance costs. Consequently, my revised proposal differentiates renewable and non-renewable price streams on the basis of avoided Oregon RPS compliance costs rather than differentiating the two price streams based upon whether a QF defers a renewable resource. Because the distinguishing feature between the two price streams is tied to avoided RPS compliance costs, it is more precise to refer to the two price streams as the "RPS avoided cost price stream" and the "non-RPS avoided cost price stream."

Q. Please describe PacifiCorp's proposed non-RPS price stream.

A. The avoided cost for the non-RPS price stream is based on a QF deferring a capacity-equivalent amount of the next cost-effective resource in the IRP preferred portfolio. Under this proposal, a QF would defer cost-effective renewable resources, included in the IRP preferred portfolio to reliably meet system load, of the same type (*i.e.*, the like-for-like concept introduced in my January 2017 opening testimony). If there is no like-for-like resource in PacifiCorp's preferred portfolio during a QF's proposed term, avoided cost pricing for these QF resources would be based on deferring a capacity-equivalent amount of the next major thermal resource.

Q. What is PacifiCorp's updated proposal for determining the renewable price stream?

A. Oregon RPS compliance is based on retirement of renewable energy certificates (RECs). REC ownership has no impact on PacifiCorp's treatment of QF output when calculating avoided energy and capacity costs because system operations and dispatch would be the same for a given project regardless of REC ownership. Under PacifiCorp's updated proposal, the RPS avoided cost pricing stream reflects the non-RPS avoided cost price stream plus avoided Oregon RPS compliance costs.

Q. Is this docket the appropriate place for the Commission to adopt PacifiCorp's updated proposal for the renewable price stream?

A. Not necessarily. As explained in the concurrently-filed policy testimony of Ms. Lockey (PAC/200), PacifiCorp's revised proposal is consistent with precedent from the Commission and the Federal Energy Regulatory Commission (FERC) regarding renewable price streams. PacifiCorp's revised proposal, however, also reveals nuanced policy considerations about renewable pricing that will have an effect outside of the narrow issue addressed in this docket (how to calculate a renewable PDDRR price stream for PacifiCorp's non-standard QF purchases). Indeed, the Commission's resolution of these policy issues will impact both standard and non-standard price streams offered by PacifiCorp and other Oregon utilities. PacifiCorp therefore believes that the appropriate path forward is to investigate these issues in a generic docket involving a full range of stakeholders and all Oregon utilities with mandatory Public Utility Regulatory Policies Act of 1978 (PURPA) purchase obligations.

Q. How should the Commission resolve these policy issues?

A. As more fully explained in Ms. Lockey's policy testimony, the Commission directed parties to engage in workshops after the closure of docket UM 1794. I understand that some of the issues to be addressed in those workshops are similar to the policy issues raised by PacifiCorp's updated proposal. The workshops provide an initial forum for determining the next procedural steps for resolution of the policy issues raised in PacifiCorp's updated proposal.

Q. Will consideration of the policy issues in a separate proceeding harm QFs?

A. No. Under PacifiCorp's updated proposal, PacifiCorp's 2017 IRP, which includes renewable resources added to meet PacifiCorp's system load, shows an Oregon RPS compliance shortfall in 2035 indicating that QFs contracting with PacifiCorp in the near term would not receive the RPS price stream. Therefore, QFs will receive the non-RPS price stream and retain their RECs until their avoided cost pricing reflects deferral of cost-effective renewable resources.

Q. If the Commission adopts PacifiCorp's proposal to address the policy issues in a separate proceeding, what issues remain for Commission resolution in this proceeding?

A. The PDDRR methodology proposed in my January 2017 opening testimony, now referred to as a non-RPS avoided cost price stream, can still be considered by the Commission in this proceeding.

Q. What are the contested issues related to the PDDRR methodology?

A. Several parties propose modifications to specific aspects of the renewable PDDRR methodology proposed in my 2017 opening testimony. Those proposals respond to my recommendations to:

1) limit deferral of renewable resources of the same type;
2) prohibit deferral of 2021 wind resources identified in PacifiCorp's 2017 IRP preferred portfolio;
3) eliminate the market price floor; and
4) continue to utilize the potential QF queue.

Q. Please summarize your response to the recommendation that renewable resources in the preferred portfolio be deferrable by QFs of any type.

A. My July 2017 opening testimony demonstrates that renewable pricing that would allow a QF to displace other types of resources is inconsistent with PacifiCorp's resource needs and avoided capacity and energy costs.

Q. Please summarize your response to the recommendation that 2021 wind resources in the preferred portfolio should be deferrable by QFs of any type.

A. QFs located in Oregon are unlikely to either defer or supplant the 2021 Wyoming wind resources in the 2017 IRP preferred portfolio. If a QF defers a production tax credit (PTC)-qualifying wind resource beyond 2020, the cost of replacing the QF's capacity and energy at the end of its term will be at a higher cost because it will not have the benefits of the PTC, leaving customers with higher costs in the future than they would otherwise incur. Such a result conflicts with PURPA's customer indifference standard. If QFs are allowed to defer the 2021 Wyoming wind resource included in the 2017 IRP preferred portfolio, it would upset the economic calculus behind both the transmission investments and the wind investments, and would cause customers to pay higher costs that do not reflect an optimized resource portfolio that takes full advantage of PTCs.

Q. Please summarize your response to the recommendation that the market price floor remain in place.

A. The market price floor significantly increases avoided costs relative to the PDDRR methodology, does not correspond to the treatment of QF generation in the development of retail prices in contradiction with the PURPA customer indifference standard, and disregards the impact of previous QF additions on PacifiCorp's avoided capacity and energy costs. In addition, QF output is not delivered to markets and is not equivalent to firm market transactions, particularly the monthly market prices on which it is based.

Q. Please summarize your response to the recommendations related to the potential QF queue.

A. To address parties' concerns about the effect of the potential QF queue on avoided cost pricing, I propose additional procedures to ensure that QF-contract negotiations proceed in a timely manner, allowing all QFs an opportunity to receive prices from the top of the potential QF queue while ensuring that customers are protected from paying more than PacifiCorp's forecast of avoided costs.

RENEWABLE AND NON-RENEWABLE PRICING OPTIONS

Q. Please describe your updated proposal for the RPS avoided cost price stream.

A. My proposal aligns the renewable price stream with PacifiCorp's avoided RPS compliance costs. The RPS avoided cost price stream reflects the non-RPS avoided cost price stream plus avoided Oregon RPS compliance costs.

Q. What RPS compliance cost do you recommend including in the RPS avoided cost pricing streams?

A. Avoided RPS compliance costs should be based on the value to the utility of deferring a future RPS compliance shortfall. PacifiCorp's 2017 IRP shows an RPS compliance shortfall in 2035. PacifiCorp's RPS compliance cost for 2035 is the net present value of the least-cost RPS compliance instruments available to be acquired between now and 2035.

Q. Do you propose a specific cost here?

A. No. As previously discussed, the harm to QFs from not having an RPS avoided cost price option is limited since PacifiCorp's Oregon RPS compliance shortfall is not until 2035, which for QFs having projected commercial operation dates prior to 2020, is beyond the 15-year portion of a maximum contract term for which QF pricing is not based on a market index. In addition, RECs from Oregon QFs are exempt from restrictions on the use of unbundled RECs for RPS compliance, so the value of RECs a QF retains will remain the same whether acquired through a power purchase agreement or separate REC purchase agreements. In light of these factors, not having an RPS avoided cost price option while waiting for resolution of the policy questions related to Oregon RPS compliance costs will not be unduly burdensome to QFs.

Q. Does your modified proposal for an RPS-based avoided cost price stream clarify the cost-allocation concerns raised by the Coalition?

A. Yes. Under PacifiCorp's revised RPS avoided cost proposal, pricing consists of avoided RPS compliance costs added to non-RPS avoided cost pricing. The differentiation of renewable avoided cost pricing is consistent with FERC and Commission guidance regarding renewable price streams reflecting compliance with state-imposed requirements, such as Oregon's RPS regulations. Oregon customers would be responsible for all of the avoided cost associated with RPS compliance, and would receive all of the RECs acquired or allocated for Oregon RPS compliance. Because the avoided RPS compliance costs are discrete additions with defined timeframes, cost-allocation and REC assignment are straightforward.

Q. Does the presence of a renewable resource in the preferred portfolio indicate that PacifiCorp faces incremental Oregon RPS compliance costs?

A. No. Simply put, the renewable resources in the preferred portfolio are not proposed to address an RPS compliance shortfall (i.e., renewable resource deficiency). Based upon its 2017 IRP, PacifiCorp does not have an Oregon RPS compliance shortfall until 2035. The renewable resources identified in PacifiCorp's 2017 IRP come online well before 2035, and are included in the preferred portfolio because they are the least-cost, least-risk resources that are used to reliably meet system load. The renewable resources identified in the preferred portfolio supply lower cost energy and capacity than other resource alternatives and would remain in the preferred portfolio even if the Oregon RPS ceased to exist. Consequently, Oregon RPS compliance costs cannot be attributed to these renewable resources and the cost for these renewable resources should not be considered when developing an avoided cost pricing stream based on RPS compliance costs.

Q. Are there any special considerations related to the RECs associated with deferral of cost-effective renewable resources from PacifiCorp's preferred portfolio?

A. To the extent the Commission establishes a value for avoided RPS compliance costs as contemplated by PacifiCorp's updated proposal, it would be appropriate to account for any difference between a QF's generation and that of the renewable resource it is deferring.

Q. Does the 2017 IRP identify any renewable resources to be acquired for compliance with the Oregon RPS?

A. No. The 2017 IRP preferred portfolio does not include any renewable resources added for the purpose of meeting Oregon RPS targets; however, as previously discussed, the 2017 IRP Action Plan calls for PacifiCorp to issue RFPs for unbundled RECs. As a result, determining the appropriate treatment for situs physical resources under the PDDRR methodology is moot at this time. It would be reasonable to address the treatment of renewable resources added for the purposes of meeting Oregon RPS targets in conjunction with the consideration of methodologies for determining avoided RPS compliance costs in a separate proceeding.

RESPONSE TO PARTIES' RENEWABLE PRICING STREAM PROPOSALS

Q. Do parties offer renewable pricing stream proposals based on the energy output of a renewable resource?

A. Staff suggests that it may be appropriate to use the PDDRR methodology to allow a renewable QF to defer an equivalent volume of energy from a renewable resource in PacifiCorp's preferred portfolio. An RPS pricing stream based on a single RPS avoided cost for all renewable resource types takes this proposal to its logical conclusion, by recognizing that resource eligibility for RPS compliance does not impact system dispatch.

Q. Do parties offer any other alternatives for developing a renewable pricing stream?

A. Staff supports adjusting standard avoided cost prices to account for a specific QF's characteristics, based on the factors prescribed by FERC.[1]

Q. Does PacifiCorp support this proposal from Staff?

A. No. The current standard renewable pricing methodology significantly overstates PacifiCorp's avoided RPS compliance cost.

Q. Do standard renewable prices reflect a single avoided RPS cost for all QF types?

A. No. PacifiCorp's non-renewable and renewable standard avoided cost prices approved on October 25, 2016, were presented in Staff's testimony.[2] The only difference between a QF selecting the standard renewable avoided cost and the same QF selecting the standard non-renewable avoided cost is the transfer of RECs in support of RPS compliance.

Consistent with the policies articulated by FERC and the Commission, and more fully described in Ms. Lockey's policy testimony, standard renewable prices should reflect PacifiCorp's costs to meet its Oregon RPS obligations. Table 1 below illustrates that the implied cost of RPS compliance, calculated as the difference between standard non-renewable and renewable prices in calendar year 2028, varies by technology type and delivery period (on and off peak). These variations are not consistent with PacifiCorp's RPS compliance obligations, which are indifferent to different types of RPS-eligible resources and to energy generated during on and off-peak periods. Table 1 shows only the implied cost of RPS compliance under the

[1] Staff/100 Andrus/6.
[2] Staff/100 Andrus/12.

standard renewable avoided cost prices and does not include the value of a QF's energy or capacity.

Table 1: Implied Cost of RPS Compliance in Standard Renewable Avoided Cost Prices ($/MWh)

	On-Peak	Off-Peak	On-Peak	Off-Peak
	Baseload		**Wind**	
2028	39.8	33.5	24.1	33.5
	Fixed Solar		**Tracking Solar**	
2028	27.1	33.5	29.9	33.5

Q. Can the cost of RPS compliance in standard renewable avoided cost prices be reconciled to a single value?

A. Yes. A proxy wind resource is used to set the standard renewable avoided costs for other resources types, so the difference between the standard renewable and non-renewable avoided cost prices for wind reflects the fewest adjustments. Based on the expected on- and off-peak output of the proxy wind resource, PacifiCorp's standard avoided cost prices imply that the 2028 cost of RPS compliance is $28.42/MWh.

Q. Is $28.42/MWh consistent with PacifiCorp's actual costs of RPS compliance?

A. No. In Order No. 16-482, the Commission found that: (1) there is not currently a reliable way of estimating RPS compliance costs in future periods; and (2) PacifiCorp would not need to take resource actions to comply with the RPS until the mid-2020s. The Commission concluded that any reasonable estimate of those future deferred RPS compliance costs related to the loss of load from Direct Access customers would be de minimis when discounted to today's dollars. Since that time, PacifiCorp's IRP preferred portfolio has incorporated a significant quantity of cost-effective renewable resources that further delay PacifiCorp's need for actions to comply with the RPS to 2035, indicating that future RPS compliance costs will be even lower than the de minimis level identified by the Commission in Order No. 16-482.

Q. Has the implied cost of RPS compliance included in the standard renewable avoided cost prices changed recently?

A. Yes. Since this proceeding was initiated, PacifiCorp's standard avoided costs were recently updated, with new prices effective June 1, 2017. The implied cost of RPS compliance in 2028 associated with the updated prices has increased to $33.16/MWh, primarily as a result of a reduction in the non-renewable price stream.

Q. How do the RPS compliance costs derived from the current standard avoided costs compare to the cost of renewables in the 2017 IRP preferred portfolio?

A. The 2017 IRP preferred portfolio includes cost-effective wind, solar, and geothermal resources as part of PacifiCorp's least-cost, least-risk plan. While these resources are included in the preferred portfolio regardless of their renewable attributes, they will defer PacifiCorp's RPS compliance need from 2030 to 2035. Because the renewable resources are cost-effective and being added to reliably meet system load, the RPS compliance cost of these resources is zero.

Q. What do you propose regarding RPS compliance costs?

A. As more fully explained in Ms. Lockey's policy testimony, RPS compliance costs should be determined in a separate proceeding. QFs entering contracts in the interim would retain their RECs until their avoided cost pricing reflects deferral of cost-effective renewable resources.

PDDRR METHODOLOGY

Q. Please summarize the parties' positions with regard to the PDDRR methodology generally.

A. Certain aspects of the capacity contribution-based PDDRR methodology proposed by PacifiCorp were addressed by many parties and are each separately addressed in other sections of my testimony. These topics include PacifiCorp's proposals to: limit deferral to renewables of the same type, not allow deferral of 2021 wind resources, eliminate the market price floor, and continue to utilize the potential QF queue.

With regard to the PDDRR methodology in general, ICNU agrees with PacifiCorp's initial proposal for calculating avoided costs. The Joint Parties, supported by CREA, opposed certain details, but did not oppose the PDDRR methodology generally. ODOE similarly opposes certain aspects of PacifiCorp's proposal, and also proposes incorporating updates in avoided cost calculations beyond the date a contract is signed.

Staff proposes an alternative PDDRR methodology based on deferral of energy-equivalent renewable resources, with the intent of being more consistent with RPS compliance obligations. Staff also suggests that returning to the previous non-standard avoided cost methodology, which was based on specific adjustments to standard prices, may be necessary if its proposal to use an energy-equivalent PDDRR is not adopted.

The Coalition also supports returning to the previous methodology if non-standard prices are not roughly comparable to the published price offered to QFs in standard contracts.

Q. What is the position of ODOE with regard to the timing of updates to avoided cost inputs?

A. ODOE asks the Commission to clarify that the schedule for updating inputs to non-standard avoided costs adopted in Order No. 14-058 should continue to be used.

Q. How do you respond?

A. This specific issue was addressed in my January 2017 opening testimony.[3] The updates incorporated in the determination of non-standard avoided costs are consistent with the methodology the Commission approved in Order No. 16-174.

Q. Do you have any additional comments on this issue?

A. Yes. Under PURPA, QFs are entitled to avoided costs calculated at either the time of delivery or at the time the obligation is incurred. Even allowing for the administrative difficulties of managing updates to standard prices, using cost, performance, and system requirement information from a past IRP that was locked down in 2014 during the early stages of IRP preparation is not consistent with setting an avoided cost at the time the obligation is incurred and is at odds with PURPA.

Q. Both Staff and the Coalition support prices derived from standard avoided costs. Should standard and non-standard avoided cost prices be roughly comparable for an equivalent project?

A. Yes. But I question the Coalition's conclusion that the detailed and comprehensive determination of avoided costs using the PDDRR methodology and the Generation and Regulation Initiative Decision Tools (GRID) model is less accurate than the outdated, simplistic assumptions incorporated in standard avoided cost prices. As I

[3] PAC/100, MacNeil/8.

described above with regard to ODOE's opposition to updating avoided cost inputs, standard avoided cost prices incorporate several inputs that were established in 2014. As previously noted in Table 1 above, standard renewable prices include levels of compensation for RECs that vary by resource type and delivery period, neither of which is relevant to RPS compliance. As a result some of the prices are necessarily deviating from avoided cost to the detriment of customers. Finally, the compensation for RECs in the current standard renewable prices is far in excess of PacifiCorp's expected Oregon RPS compliance costs.

Q. The Coalition suggests that since the GRID model is overly complex and controlled by PacifiCorp, it is likely to result in lower QF prices. How do you respond?

A. First, I would note that the Commission has already determined that the PDDRR methodology more accurately forecasts avoided costs. The relevant issue is not whether the GRID model results in lower or higher QF prices; the relevant issue is whether the GRID model results in a more accurate forecast of avoided costs, which it does. A sophisticated model is necessary to accurately account for the wide-ranging conditions experienced in actual operations. This is increasingly true as the proportion of PacifiCorp's load met with intermittent solar and wind resources increases. The proportion of regional load met by these resources is also relevant as it drives volatility in market prices, increasing the value of flexible resources and reducing the value of uncontrollable resources.

As experience with these effects grows, I anticipate that GRID model inputs and assumptions will need to become more sophisticated. While GRID is used for determining avoided cost pricing, it is first and foremost used to set the rates paid by retail customers, whom also pay for QF purchases and receive the associated benefits from QF generation. Ultimately, the GRID model and PDDRR methodology need to be sufficiently sophisticated to ensure retail customers pay just and reasonable rates.

Second, after signing a non-disclosure agreement, QF developers may request access to the GRID model, including all inputs and outputs associated with their indicative pricing request. PacifiCorp provides GRID assistance to help users locate the information of interest to them, most of which is readily available. PacifiCorp also routinely responds to data requests from developers seeking additional background on the assumptions in their indicative pricing. To the extent their concerns cannot be resolved, QFs may bring contested issues related to their indicative pricing to the Commission.

Finally, I would note that both witnesses with significant experience with the GRID model (ICNU and the Joint Parties) support the PDDRR methodology in some form.

Q. The Coalition indicates that QFs should be allowed to challenge the implementation of the PDDRR methodology on an as-applied basis. How do you respond?

A. The procedures for the negotiation of avoided cost purchases from non-standard resources specify that a QF may file a complaint asking the Commission to adjudicate any unresolved contract terms or conditions.[4] A pricing dispute would be covered by this clause.

DEFERRAL OF LIKE RENEWABLES

Q. Please summarize PacifiCorp's proposal to allow QFs to defer renewable resources identified in its IRP preferred portfolio.

A. Under the proposed renewable PDDRR methodology, a renewable resource would be eligible to defer the next major renewable resource of the same type in the IRP preferred portfolio, based on equivalent-capacity contributions.

Q. Do you agree with parties' proposals that all renewable QF resources should be eligible to defer any renewable resource identified in the IRP preferred portfolio?

A. No. The identified wind, solar, and geothermal resources are cost-effective components of the least-cost, least-risk portfolio. The IRP preferred portfolio analysis does not include any special obligations for the acquisition of renewables or include any value for renewable attributes, and only accounts for the contribution of their operating characteristics to the composition and dispatch of PacifiCorp's portfolio of resources. As a result, labeling resources as "renewable" is not pertinent to the composition of the preferred portfolio. Ensuring reasonable alignment between the operating characteristics of a QF and the resources it defers from the preferred portfolio helps to ensure that the least-cost, least-risk outcomes achieved by the preferred portfolio are maintained.

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[4] AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES OF GREATER THAN 10,000 KW. Available at: https://www.pacificpower.net/content/dam/pacificorp/doc/Efficiency_Environment/Net_Metering_Customer_Generation/Avoided_Cost_Purchases_from_Qualifying_Facilities_of_Greater_than_10_000_kw.pdf.

Q. What is meant by renewables of the same type?

A. The "type" is meant to reflect the operational characteristics of the QF on PacifiCorp's system, not the specific technology of the resource identified in the preferred portfolio. The 2017 IRP preferred portfolio includes wind, solar, and geothermal resources. The geothermal resource in the 2017 IRP preferred portfolio is expected to have a flat generation profile with little daily or seasonal variation. Biomass, biogas, hydro, and other renewable resources with similar output profiles would also be eligible to displace the geothermal resource. Any resource with relatively flat output over a daily and monthly timeframe would be considered a resource of the same type as the geothermal resource in the 2017 IRP.

Q. Are there additional considerations associated with capacity deferral by other renewable resource types?

A. Yes. Resources that can be economically dispatched by PacifiCorp to their maximum output would have capacity contributions based on their maximum output. Resources that cannot be economically dispatched by PacifiCorp have capacity contributions based on their expected output relative to the availability of the deferrable thermal or baseload resource identified in the IRP. Resources with seasonal variations in output would have capacity contributions based on their output during the months of PacifiCorp's peak load requirements, as identified in the loss of load probability study used to develop the wind and solar capacity contribution values in the IRP. These distinctions ensure that the capacity provided by a QF is equivalent to the capacity being removed from the IRP preferred portfolio when forecasting avoided costs.

Q. Please respond to ODOE's statement that PacifiCorp has not adequately explained why an imbalance is created when different renewable technologies are deferred.

A. PacifiCorp's 2017 preferred portfolio ensures that each load bubble can meet the specified planning reserve margin of 13 percent, inclusive of imports of excess resources from other transmission areas. Imports are restricted to the firm transmission rights between each area. The GRID model does not enforce the planning reserve margin requirements by transmission area, and PacifiCorp's PDDRR allows for displacement of wind and solar resources from across PacifiCorp's system with only limited restrictions.

As an example, replacing wind resources that generate more in the winter with solar resources that generate more in the summer is likely to result in periods when transmission prevents delivery of resources to the locations where they are needed. Daily and seasonal shapes of solar and wind resources are complementary and can make better use of limited transmission resources than either resource on its own.

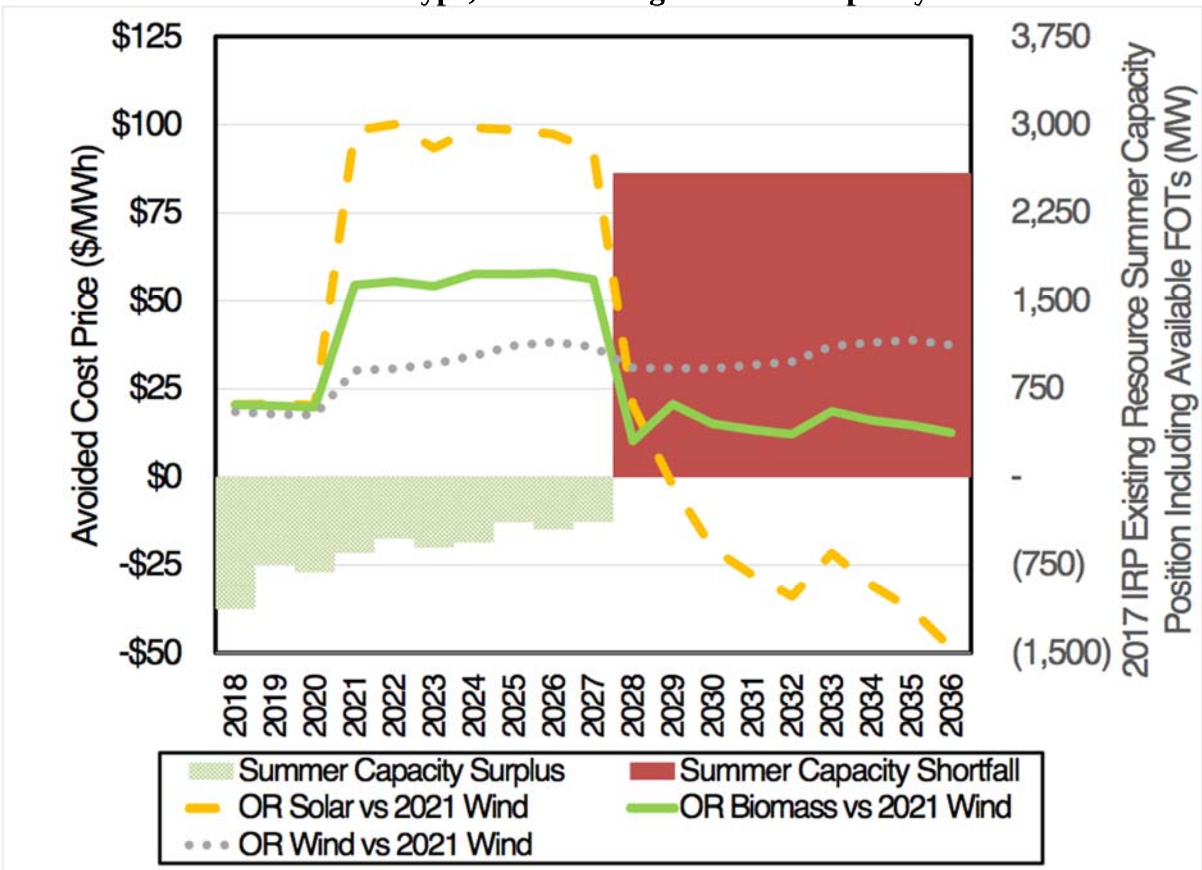
Wind and solar resources also exhibit significant variation both within the hour and over multiple hours. While the cost of maintaining flexible capacity within the hour is included in the IRP analysis, the cost of adjusting PacifiCorp's resource balance to accommodate solar and wind ramping has not been fully quantified. PacifiCorp's optimization models determine least-cost market transactions to balance the solar and wind in each hour independently.

In actual operations, PacifiCorp must rely on a combination of day-ahead block products and a limited supply of hourly transactions at prices that are often unfavorable—a tendency toward high prices when PacifiCorp is purchasing and low prices when PacifiCorp is selling. Renewable QFs will exacerbate these costs if their variations are correlated with other resources already in PacifiCorp's portfolio or with resources across the broader region, particularly as it becomes increasingly integrated via the Energy Imbalance Market. Deferring like renewable resources thus ensures that a QF results in a portfolio with a comparable risk profile.

Q. Can you provide more detail on the inconsistencies when deferral of varying renewable resource types occurs?

A. In response to the Coalition's data requests, PacifiCorp prepared indicative avoided cost pricing for 20 MW wind, solar, and biomass resources. Figure 1 shows the annual avoided cost using the PDDRR methodology when these same resources instead defer capacity-equivalent amounts of the 2021 wind resource in PacifiCorp's 2017 IRP preferred portfolio. The 2021 wind resource was selected to provide a sense of the range of variation in avoided costs over the course of the IRP forecast period and a QFs contract term. On the right axis of Figure 1 is PacifiCorp's summer capacity position when only existing resources and available front office transactions (FOTs) are considered (*i.e.*, not including any new resources), as identified in the 2017 IRP. PacifiCorp has surplus capacity through 2027, and a capacity shortfall starting in 2028.

Figure 1: Avoided Cost Assuming Deferral of IRP Wind Resources, by Resource Type, with Existing Resource Capacity Position



Q. Are the solar and biomass avoided cost prices shown in Figure 1 reasonably consistent with PacifiCorp's capacity needs and costs?

A. No. The discrepancy is most evident in the prices for a solar QF, which are extremely high and much higher than PacifiCorp's avoided cost through 2027, but drop precipitously in 2028 and become negative in 2029 when the QF would be required to pay PacifiCorp for each MWh it delivered to PacifiCorp's system. Faced with these avoided costs, a solar QF would be expected to elect a ten-year contract term through 2027, which does nothing to address PacifiCorp's capacity needs in 2028.

Through 2027 existing resources and capacity available from FOTs are sufficient to meet PacifiCorp's summer capacity needs, so avoided capacity costs are expected to be low—at or below market prices, not significantly in excess of market prices.

Starting in 2028, FOTs are not sufficient to meet PacifiCorp's summer capacity needs and more expensive thermal and renewable resources are required, so a drop in avoided capacity in this time frame is not reasonable. The effect for a biomass QF is of a smaller magnitude, but still reflects a more than 80 percent reduction in avoided costs from 2027 to 2028.

Q. How do these avoided costs compare to cost assumptions for solar resources in the 2017 IRP?

A. The 2017 IRP included Oregon solar resource options that were not selected as part of the preferred portfolio, indicating that lower-cost, lower-risk resource alternatives were available. The cost of an Oregon tracking solar resource in the 2017 IRP was $61/MWh in 2021, rising at inflation to $70/MWh in 2027. This is well below the avoided cost of solar based on displacement of the 2021 wind resources shown in Figure 1, which range from $92-$100/MWh in this same time frame. The fact that this resource was not selected as part of the 2017 IRP preferred portfolio indicates that actual avoided costs through 2027 are even lower.

Q. Why do these resources produce such significant variations in avoided cost?

A. Generally these variations reflect the relative quantity of capacity and energy provided by each of the QF resources. As shown in Table 2, wind resources provide the least amount of capacity relative to energy, while solar resources provide the most. The significant variation in the relative value of energy and capacity results in different resources being more valuable at different periods of the IRP forecast based on their overall characteristics. While the PDDRR methodology and GRID model cannot reflect a comprehensive reoptimization of PacifiCorp's resource portfolio, deferral of renewable resources of the same type has the greatest potential to maintain the least-cost, least-risk characteristics of the preferred portfolio.

Table 2: Capacity to Energy Ratios

Resource	Capacity Factor	Capacity Contribution	Capacity to Energy Ratio
Oregon Solar	28.8%	64.8%	2.25
Oregon Biomass	100.0%	100.0%	1.00
Oregon Wind	28.2%	11.8%	0.42
2021 IRP Wind	41.2%	15.8%	0.38

Q. Is there a place for resources producing predominantly energy, rather than capacity?

A. Yes. Utility systems have traditionally included both peaking units built primarily for capacity, and baseload units built for energy production. Solar units share many characteristics with peaking units because they have relatively high all-in cost per unit output, but greater contribution to serving peak requirements. On the other hand, wind units generally have a lower cost per unit output, along with a lower contribution to serving peak requirements. Coal units have traditionally provided much of the energy on PacifiCorp's system and the significant coal plant retirements assumed in the 2017 IRP result in a greater need and associated value from low-cost energy resources such as wind when compared to solar resources.

Q. Are there significant differences between the generation of the QF resources and the 2021 IRP wind they would displace as described above?

A. Yes. Because a 20 MW Oregon solar QF provides capacity equivalent to 81 MW of 2021 IRP wind and has a lower capacity factor, PacifiCorp loses six RECs from the 2021 IRP wind resource for each REC received from the QF. Similarly a 20 MW Oregon Biomass QF provides capacity equivalent to 127 MW of 2021 IRP wind and has a higher capacity factor. The higher capacity contribution partially offsets the capacity deferral, but PacifiCorp still loses 2.7 RECs from the 2021 IRP wind resource for each REC received from the QF. On the other hand, the Oregon wind QF generates 18 percent more RECs than the 2021 IRP wind resource. As a result, even if PacifiCorp receives the RECs from solar or biomass QFs, its Oregon RPS compliance needs would increase significantly as a result of the greater loss of generation from displaced IRP wind resources.

NEW WIND AND TRANSMISSION

Q. Several parties state that the wind and transmission resources identified in PacifiCorp's 2017 IRP preferred portfolio should be deferrable by any renewable QF. Do you agree?

A. No. The 1,100 MW of new PTC-eligible Wyoming wind resources added in 2021 (as a proxy for a December 31, 2020 in-service date to ensure the assumed tax benefits are achieved) is tied to the Aeolus-to-Bridger/Anticline transmission line (Energy Gateway Sub-Segment D2). The new wind and transmission associated with this project provides all-in economic benefits to PacifiCorp customers in all jurisdictions. Therefore, QF projects that do not interconnect with and/or use PacifiCorp's

Wyoming transmission system (*i.e.*, Oregon QFs) to deliver energy and capacity in this timeframe would not partially displace or defer any of the 1,100 MW of new wind associated with the project.

Q. Please describe the partial displacement methodology.

A. A 10 MW Oregon tracking solar QF can defer 10.9 MW of an east-side tracking solar resource or 6.5 MW of a thermal resource from an IRP preferred portfolio.[5]

In both cases, the IRP resource is reduced in size by exactly the capacity contribution of the QF, even though resources generally have to be constructed in discrete sizes. This captures the PURPA requirement that avoided costs should take into the account smaller capacity increments and the shorter lead times available with additions of capacity from QFs.

Q. How does the partial displacement concept relate to the potential deferral of the 2021 Wyoming wind resources included in the 2017 IRP preferred portfolio?

A. Two characteristics of the 2021 Wyoming wind resources make them inappropriate to consider for capacity deferral. First, these resources cannot be deferred to a later date, as they would not qualify for the PTC after December 31, 2020. The loss of the PTC would eliminate much of the benefits associated with the 2021 Wyoming wind resources. And without those benefits, the Wyoming wind would not be part of PacifiCorp's least-cost, least-risk plan to reliably meet system load.

Second, the transmission line that enables the addition of these resources to PacifiCorp's system cannot be reduced in size. To the extent it is economic to build it at all, an optimized resource plan would continue to include as much of the 2021

[5] East Tracking Solar: 59.7%. West Tracking Solar: 64.8%. 64.8% / 59.7% = 109%
Thermal Resource: 100%. West Tracking Solar: 64.8%. 64.8% / 100% = 65%

Wyoming wind resource as possible, so long as it provides benefits in excess of its costs. As a result of these characteristics, resources outside of the area of the new transmission line would not either delay or supplant the 2021 Wyoming wind resources in the 2017 IRP preferred portfolio.

Q. Does the expiration of the PTC create differences in deferral value when compared to other resources that are not eligible for the PTC?

A. Yes. For most resources, the real-levelized annual cost assumed in the IRP is fixed, so a plant built at a later date has the same real cost as a plant built today. As a result, if a QF defers a gas plant for five years, the gas plant can be built in year six at the same real-levelized cost that would have been incurred in year six if the QF had not deferred the gas plant for five years.

This is not the case for a PTC-qualifying wind resource, as wind resources online by the end of 2020 will receive the full value of the PTC, whereas wind resources constructed at a later date will receive a reduced PTC value (or no value at all). As a result, if a QF defers a PTC-qualifying wind resource for five years beyond 2020, their real-levelized annual cost in year six will be higher than if they were built before the end of 2020. So a QF deferring the 2021 Wyoming wind resource in the IRP would leave customers with higher costs in the future than they would otherwise incur.

Q. Should the fact that the 2021 wind resources are renewable influence the determination of whether they are deferrable?

A. No. As previously discussed, the 2017 IRP preferred portfolio does not assign any additional value to renewables, simply for being renewable resources, relative to other resource options. As such, if capacity contribution is the only pertinent factor for determining resource deferral, the entire 2021 wind project could be deferred by 174 MW of baseload resources of any type.

Q. Have you prepared indicative avoided costs assuming 2021 Wyoming wind could be deferred by resources outside of the area supported by the Wyoming transmission additions?

A. Yes. Table 3 provides a comparison of avoided costs based on the proposed partial displacement of like renewables (and excluding displacement of the 2021 Wyoming wind resource), relative to partial displacement of 2021 Wyoming wind by any renewable resource as proposed by parties. For ease of comparison these results do not reflect the potential QF queue or the market price floor.

Table 3: 15-year Levelized Avoided Cost Prices Starting 2018

Deferral	Solar	Wind	Biomass
Like Renewables	$38.12	$26.87	$30.94
2021 Wind	$50.36	$28.79	$36.15

Q. Does the additional value shown in Table 3 as a result of deferring 2021 Wyoming wind reasonably reflect PacifiCorp's avoided cost?

A. No. As shown in Figure 1 and previously discussed, the avoided cost results for solar and biomass resources have dramatic inconsistencies over time when they are assumed to defer the 2021 Wyoming wind resource.

Q. What do you conclude with regard to deferral of the 2021 Wyoming wind resource?

A. It is inappropriate to partially displace the 2021 Wyoming wind resource based on resource additions outside of the constrained area connected by the proposed transmission line.

MARKET PRICE FLOOR

Q. Can you please summarize the issues raised by parties concerning PacifiCorp's proposal to remove the market price floor?

A. Parties' substantive issues are related to two elements of the market price floor. First, parties claim that only transmission limits can impact the applicability of the market price floor. Second, parties claim that the GRID model understates avoided cost and the market price floor represents a more accurate measure of avoided cost.

Q. Do parties have an accurate understanding of PacifiCorp's transmission rights?

A. No. ODOE erroneously claims that PacifiCorp's modeled transmission constraints are highly speculative, and that the Mid-Columbia market is between PacifiCorp's generation and its loads, neither of which is accurate.

Q. Are the transmission constraints modeled in GRID highly speculative?

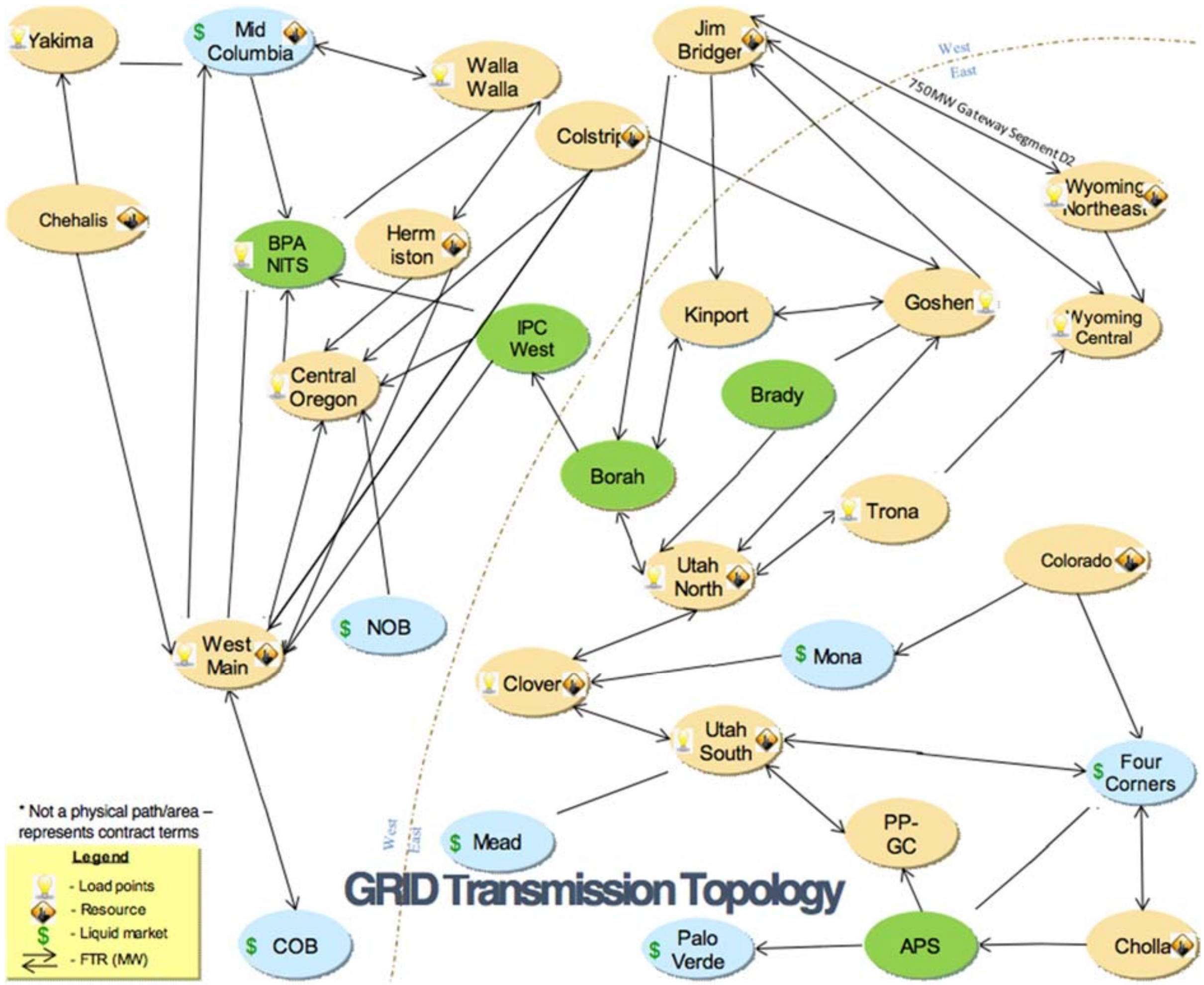
A. No. The transmission constraints in the GRID model reflect the sum of PacifiCorp's long term firm transmission rights between each transmission area in the model. Each of PacifiCorp's transmission reservations has a specified point of receipt and point of delivery. To manage performance of the GRID model, closely located delivery points which do not normally have binding transmission limits between them in actual operations are aggregated to the transmission areas represented in GRID. Transfer capability within a single transmission area is thus effectively unlimited.

Transmission outages or changes in the load and resource mix in the area can lead to binding transmission limits not represented in GRID. The GRID model also includes historical levels of short term and non-firm rights at zero incremental cost.

Q. Is the Mid-Columbia market between PacifiCorp's generation and its loads?

A. While the Mid-Columbia market is geographically west of PacifiCorp's resources in Idaho, Utah, and Wyoming, and east of the majority of its Oregon loads, PacifiCorp's long-term firm transmission rights into the Mid-Columa market are limited, as its primary transmission connection from east to west passes through central Oregon on its way to southern Oregon (a.k.a. West Main) and does not intersect with the Mid-Columbia market. The transmission topology used in PacifiCorp's GRID model is shown in Figure 2. The same figure including PacifiCorp's transfer rights between bubbles is provided as Exhibit PAC/301.

Figure 2: GRID Model Transmission Topology



Q. Are the transmission constraints experienced by PacifiCorp the same as the transmission constraints that might be identified in a QF's interconnection request?

A. No. In accordance with FERC rules, PacifiCorp's Open Access Transmission Tariff (OATT) identifies the two distinct duties of PacifiCorp's transmission function: generation interconnection service and transmission service. An Oregon QF's generation interconnection study identifies the transmission modifications necessary to deliver the aggregate generation in the area of the proposed resource to a network customer's network load without displacement of existing or higher queued network resources or QFs. The studies examine the transmission system at peak and minimum load under a variety of severely stressed conditions in order to determine the necessary transmission modifications.

Q. ODOE claims that there is no need to address transmission issues outside of load pockets, and PacifiCorp has requested closure of docket on transmission for load pockets. Why did PacifiCorp request closure of the docket related to transmission for load pockets?

A. Transmission service for a QF involves two separate requests. First, a QF submits a generation interconnection request and PacifiCorp's transmission function performs a study identifying the changes necessary to connect the proposed resource to the system and deliver its output to load.

Second, after a power purchase agreement with the QF has been signed, PacifiCorp's Energy Supply Management (ESM) function submits a transmission service request for the right to transfer the QF's output from its interconnection point to PacifiCorp's network loads. In accordance with PacifiCorp's OATT and FERC regulations, these two processes are separate and independent.

Furthermore, ESM's request cannot be submitted until a commitment has been made to accept a resource's output. Transmission service requests submitted by other transmission customers and other changes to the transmission system can occur between the time a QF signs its interconnection agreement and the time it signs the power purchase agreement, which enables ESM to submit a transmission service request. As a result, ESM does not have assurance that transmission service sufficient to deliver a QF's output to its network loads will be available. If sufficient transmission service is not available, ESM could be faced with additional costs for transmission system upgrades or third-party transmission.

While PacifiCorp requested that QFs be made responsible for such costs, I understand that the FERC precedent for cost allocation between a QF's generation interconnection request and PacifiCorp ESM's transmission service request does not support this position. As a result, PacifiCorp concluded that it was inappropriate to request that QFs be allocated the costs identified in PacifiCorp ESM's transmission service request and requested closure of the docket where it had proposed allocating those costs to QFs.

Q. Are there conditions when it is appropriate to adjust indicative pricing for identified transmission issues?

A. Yes. To the extent a QF's interconnection agreement identifies network upgrades to be paid for by the QF which allow the delivery of the QF to load elsewhere on PacifiCorp's system, it would be appropriate to adjust the delivery location of the QF to reflect delivery at the identified location. Because transmission upgrades are typically required when resources exceed the load in the proposed area of the QF, the new delivery location would result in higher avoided costs.

Q. Can indicative pricing automatically incorporate transmission upgrades necessary to move a QF to load?

A. No. PacifiCorp's ESM function manages the owned and contracted resources used to serve PacifiCorp's retail load, including purchases from QFs. PacifiCorp ESM receives transmission service from PacifiCorp's transmission function. Under FERC's Standards of Conduct requirements, PacifiCorp ESM cannot receive special treatment not available to other customers of PacifiCorp transmission. As a result, PacifiCorp ESM does not have sufficient information to identify transmission upgrades for a QF. Additionally, non-public transmission information related to other transmission customer's requests cannot be communicated to PacifiCorp ESM by PacifiCorp transmission. Because a QF requesting generation interconnection service is itself a customer of PacifiCorp transmission, it must either provide the studies prepared by PacifiCorp transmission to PacifiCorp ESM or sign a waiver to allow PacifiCorp transmission to discuss its non-public transmission information with PacifiCorp ESM. As a result, indicative pricing can only incorporate information on transmission upgrades after the associated transmission studies are provided to PacifiCorp ESM.

Q. Please reiterate the second theme of parties' opposition to removing the market price floor.

A. Parties conclude, without evidence, that the market price floor is a more accurate representation of PacifiCorp's avoided cost than the GRID results.

Q. Are the monthly market prices reflected in the market price floor an accurate representation of PacifiCorp's avoided cost?

A. No. First, in accordance with North American Electric Reliability Corporation (NERC) reliability standard BAL-002-WECC-2, which took effect in October 2014, PacifiCorp must hold contingency reserves equal to 3 percent of generation for on-system QF resources, but does not need to hold contingency reserves for market purchases. The cost of holding these reserves is not reflected in the current market floor.

Second, monthly market prices assume that a QF's output will either displace a purchase from that market or support an additional sale at the market. If PacifiCorp is purchasing at multiple markets, purchases at the highest cost market would be displaced first and additional QF resources would then displace purchases from lower cost markets. If PacifiCorp's resources are less than the market price, it will not need to purchase from the market but may be able to make sales. However, if PacifiCorp has sufficient resources less than the market price to serve load and fill up its transmission rights to a given market, the QF will be unable to support an additional sale at that market. These conditions routinely occur.

Third, even if transmission is available to deliver resources to electricity markets, those markets have limited depth. When preparing indicative avoided cost pricing for Oregon QFs, the GRID model uses the relaxed market capacity limits approved by the Commission in docket UE 245 (Order No. 12-409), rather than the more stringent limits applied in PacifiCorp's other jurisdictions.

The market price floor incorrectly assumes that unlimited volumes can be sold at the market price, in excess of the caps approved by the Commission. To the extent willing buyers cannot be found or market prices fall in response to the quantities available from PacifiCorp and other market participants, the average market price reflected in the market price floor will overstate PacifiCorp's avoided cost.

Q. Can QF generation integrated solely with market transactions?

A. No. The 2017 IRP included a "Flexible Reserve Study," which calculated the reserve requirements and costs associated with balancing variations in load, wind, solar, and non-variable resources to maintain PacifiCorp's system reliability and comply with NERC reliability standards.[6] The Flexible Reserve Study identifies wind integration costs of $0.57/MWh (2016$), and solar integration costs of $0.60/MWh (2016$). This represents the cost of keeping dispatchable PacifiCorp resources available to compensate for variations in the output of wind and solar resources. While specific integration costs were not calculated on for non-variable resources, the study did identify regulation reserve requirements for these resources that were equivalent to 2.3 percent of their nameplate capacity.[7] In accordance with the proposal in my direct testimony,[8] integration costs would be included in the avoided costs for any solar or wind QF. To the extent a QF is deferring a solar or wind resource, it would also avoid the integration costs associated with the deferred solar or wind resource's generation.

Q. If integration costs are accounted for, are market prices a reasonable representation of a QFs avoided cost?

A. No. Integration costs only reflect the cost of maintaining a supply of dispatchable capacity to compensate for changes in loads and resources. To the extent a QF's output varies from forecasted levels, PacifiCorp's dispatchable resources must increase or decrease their output to compensate. PacifiCorp's avoided cost would then reflect the dispatch costs of those resources.

[6] 2017 Integrated Resource Plan. Volume II. Appendix F: Flexible Reserve Study. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf.

[7] *Id.* Table F.7.

[8] PAC/100, MacNeil/10, lines 14-16.

Q. What is the impact of the market price floor on QF purchase prices?

A. Since the 2017 IRP was published, PacifiCorp has provided indicative avoided cost prices for six proposed solar QFs in Oregon totaling 399 MW of nameplate capacity. As shown in Table 4, during the course of the proposed term, the market price floor results in indicative prices that are 54 percent higher than the prices without the floor. This would amount to additional costs with overpayments above PacifiCorp's forecasted avoided costs totaling $242 million over the fixed price term of the proposed contracts.

Table 4: Impact of the Market Price Floor on Recent Pricing Requests

			15-Year Levelized Price				
Project	**COD**	**Capacity**	**2016 Floor**	**2017 Floor**	**w/o Floor**	**Additional Cost ($)**	**% Change**
Market Price Floor: Standard Prices Approved October 25, 2016							
QF - 380 - OR - Solar	Jan-19	50	$42.54		$24.93	29,100,622	63%
QF - 383 - OR - Solar	Dec-19	80	$46.01		$28.25	49,059,119	53%
QF - 384 - OR - Solar	Dec-19	80	$44.51		$26.64	49,474,321	58%
QF - 385 - OR - Solar	Dec-19	80	$43.89		$25.78	50,201,431	61%
QF - 381 - OR - Solar	Jan-21	80	$49.82		$32.32	48,793,964	43%
Market Price Floor: Standard Prices Effective June 1, 2017							
QF - 293 - OR - Solar	Aug-19	28.6	$41.11	$35.53	$21.96	15,471,803	60%

Q. How do these indicative pricing results demonstrate the issues related to the market price floor?

A. First, while all six of the indicative pricing studies utilized PacifiCorp's March 31, 2017 Official Forward Price Curve (OFPC), the first five projects received indicative pricing incorporated the market price floor based on the March 31, 2016 OFPC used to determine standard avoided cost prices. The last project received prices after new standard avoided cost prices were approved, so its indicative pricing incorporated the market price floor based on the March 31, 2017 OFPC. The switch to the updated market price floor reduced the last project's indicative price over the term by $5.58/MWh, or 14 percent. This significant change demonstrates that using a market price floor based on market prices that are more than a year out of date may result in QF pricing that is not consistent with PacifiCorp's avoided costs at the time a contract is executed.

Second, projects 383, 384, and 385 are identical projects submitted by the same developer. Consistent with the pricing queue methodology, these projects were studied in succession. In the GRID model, the first project displaces the highest cost purchases and resources or contributes to additional sales at the highest-priced markets. The volume available to be displaced at the highest cost resources or markets is limited, so successive projects result in declining avoided costs, which is logical and expected. With the market price floor, prices during the sufficiency period are identical for all three projects, which is not consistent with the forecast of avoided costs. As a result, the impact the market price floor has on artificially inflating avoided costs increases as additional resources are considered.

Q. Does eliminating the potential QF queue eliminate the issues associated with the market price floor?

A. While eliminating the potential QF queue reduces the impact of the market price floor, it does not eliminate it. PacifiCorp provided sample indicative pricing calculations for solar, wind, and biomass resources in response to the Coalition's data requests 6.3, 6.5, and 6.7. As shown in Table 5, the previous market price floor in effect through May 31, 2017 resulted in costs which were 17 percent to 37 percent higher than the GRID model results. Under the current market price floor effective June 1, 2017, costs are still 8 percent to 18 percent higher than the GRID model results. The additional cost associated with the market price floor would increase as additional signed contracts are reflected in the GRID model.

Table 5: Impact of the Market Price Floor on Pricing without Potential QF Queue

			15-Year Levelized Price			
Project	**COD**	**Capacity**	**w/ Floor**	**w/o Floor**	**Incremental Cost ($)**	**% Change**
Market Price Floor: Standard Prices Approved October 25, 2016						
REC 6.3 Solar	Jan-18	20	$46.48	$38.12	5,586,977	17%
REC 6.5 Wind	Jan-18	20	$37.95	$26.87	10,917,589	37%
REC 6.7 Biomass	Jan-18	20	$39.62	$30.94	21,529,121	24%
Market Price Floor: Standard Prices Effective June 1, 2017						
REC 6.3 Solar	Jan-18	20	$42.15	$38.12	2,686,914	8%
REC 6.5 Wind	Jan-18	20	$32.45	$26.87	5,481,026	18%
REC 6.7 Biomass	Jan-18	20	$34.78	$30.94	9,536,322	10%

Q. What do you recommend with regard to the market price floor?

A. I continue to recommend that the market price floor be removed to align avoided cost pricing with the best forecast of the benefits retail customers will receive in actual operations. Maintaining the market price floor is in contradiction with the PURPA customer indifference standard.

POTENTIAL QF QUEUE

Q. Please summarize your proposal for managing the potential QF queue.

A. When a QF request indicative pricing, its project proposal is added to the queue of potential QFs currently negotiating contracts. Based on the distinction between RPS-based pricing and non-RPS pricing, and the proposed pricing differential based on REC value, it is not necessary for the QF to identify a specific pricing stream for indicative pricing. Instead, all potential QFs would defer cost-effective resources from the 2017 IRP preferred portfolio, which represents expected system operations in the absence of Oregon RPS obligations. This deferral does not change if a QF selects an RPS-based pricing stream including payment for avoided RPS compliance costs.

Q. Do parties have alternative suggestions regarding how the potential QF queue should be applied?

A. Yes. ODOE proposes that avoided cost prices should be updated to reflect higher queued projects that withdraw their request, with updating continuing until the project is placed in service. The Coalition suggests that the historic percentage of the queue that was constructed should be used, rather than the entire queue, and also identifies other alternatives to determine projects that are likey to be developed. The Joint Parties, supported by CREA, suggests that only signed QFs should be considered in indicative pricing, and that indicative pricing would not be subject to change for 60-90 days.

Q. Does PacifiCorp update avoided cost pricing to reflect higher queued projects that have withdrawn?

A. Yes. When repricing is requested or required, PacifiCorp updates the potential QF queue to remove any projects which have been withdrawn or not met their negotiating milestones.

Q. Are QFs always priced at the bottom of the potential QF queue?

A. No. After receiving indicative pricing, a QF may proceed to negotiating a contract, a process that typically takes several months. During this time PacifiCorp's avoided costs are likely to change, but as time passes before queued QFs will either sign contracts or drop out and the QF in question would retain its queue position. Proposed QFs in Utah are subject to milestones for negotiations and specific restrictions on changes to their proposals. The first key milestone is that a QF must request a draft PPA and submit necessary additional information within 60 days of receiving indicative pricing.

The second key milestone is that a PPA must be executed by both parties within five months of the draft PPA being provided to the QF, unless delays are caused by PacifiCorp's ESM function. If a QF misses either of these milestones it is removed from the pricing queue and will no longer impact the prices of later queued projects when they are repriced. This ensures that each QF has an opportunity to be repriced with projects that did not proceed toward a contract removed from the QF queue. Exhibit PAC/302 attached to my testimony is a proposed Business Practice for managing Oregon QF pricing requests that incorporates these milestones and would ensure Oregon QFs are appropriately reflected in the potential QF queue and removed in a timely manner.

Q. Can you provide an example illustrating how projects move up in the pricing queue?

A. Yes. PacifiCorp provided sample indicative prices for various renewable resources in response to the Coalition's data request set six. Since that data request was prepared, 141 MW of QFs have signed contracts, 568 MW of higher queued QFs have dropped out of the queue, and 450 MW of higher queued QFs have been moved to the end of the queue. When the projects from the Coalition's data request set six are repriced, the changes in the QF queue would be reflected in their updated indicative pricing. Since that data request was prepared, PacifiCorp has also received indicative pricing requests for an additional 2,211 MW of nameplate capacity.

Q. Is it appropriate to continue updating QF pricing until the project goes into service as recommended by ODOE?

A. Per the PURPA statute, QFs may select pricing based on either avoided costs calculated at the time the obligation is incurred (*i.e.*, when the contract is executed), or at the time of delivery. It is my understanding that continuing to update the contract price to reflect changes in avoided costs after the contract is executed may not be consistent with PURPA.

Q. Is the historic percentage of the potential QF queue that was constructed a reasonable proxy for providing indicative avoided cost pricing?

A. No. Utah only implemented explicit QF negotiation procedures related to the queue in mid-2016, and while PacifiCorp has used the Utah procedures as guidelines for

Oregon QFs, the obligations of QFs in Oregon have not been clearly established. As a result, the historical data available may not be representative of future conditions. In addition, avoided cost prices and QF development costs can both vary. If QF development costs drop and avoided cost prices rise, a significant number of projects could immediately become viable and sign contracts in a limited time frame. By prioritizing projects in advance and establishing milestones and time limits for negotiations, each project can receive the opportunity to be at the top of the queue without the risk of providing pricing based on the top of the queue to every project.

Q. Is there a risk in providing indicative pricing at the top of the queue to every project?

A. Per the PURPA statute avoided cost pricing is not necessarily based on the timing of contract execution. QFs may also establish or claim a legally enforceable obligation without PacifiCorp signing a contract. According to PURPA, avoided cost pricing should be calculated at the time that obligation is established. In practice, QFs often argue that this means the most recent prices provided regardless of changes in circumstances since that time. This is currently the circumstance in an open docket before the Wyoming Commission.[9]

Q. Is there a real risk of multiple signed contracts within a short time frame?

A. Yes. Table 6 presents the updated list of potential QFs ahead of the indicative pricing proposals prepared in response to the Coalition's data request set six, broken down by developer and by state. Most of the projects in PacifiCorp's potential QF queue are

[9] Docket No. 20000-505-EC-16 (Record No. 14579): Complaint of EverPower Wind Holdings, Inc. et al.

from developers with multiple projects and several developers are active in more than one state.

Parties have not contested the fact that avoided costs under the PDDRR methodology decline as additional QF resources are added. To the extent the rules allow for two contracts that displace the same marginal resources in the sufficiency period or the same increment of capacity in the deficiency period, this would result in retail ratepayers paying in excess of avoided cost.

The potential for two or more developers to sign contracts for substantial QF capacity within a short period is real. This is particularly true when changes (i.e. reductions) in avoided costs are anticipated. As a result, providing prices based on signed contracts are likely to result in customers paying more than avoided costs for QF output and is likely to cause disputes. Prices that are not subject to change for a length of time would exacerbate the risk and cost to customers, as does the absence of clear procedures establishing the necessary steps for a QF to receive an executable power purchase agreement or establish a legally enforceable obligation.

Table 6: Potential QF Queue by Developer and State

	Nameplate				QF Count			
Developer #	**OR**	**UT**	**WY**	**Total**	**OR**	**UT**	**WY**	**Total**
1	50			50	1			1
2	80	139		219	1	2		3
3		80		80		1		1
4	286			286	4			4
5		1,280		1,280		16		16
6	55	58		113	1	1		2
7			240	240			3	3
8	55			55	1			1
9			280	280			4	4
10	160			160	4			4
11			40	40			1	1
12	18			18	1			1
Total	704	1,557	560	2,821	13	20	8	41

Q. The Joint Parties recommend that indicative pricing assume that only signed contracts are included in the QF pricing queue and that indicative pricing is not subject to change for a specified time. Is there a circumstance under which it might be reasonable to include only signed contracts in the QF queue?

A. Yes. If a QF signs a final execution version of a contract which is subject to the determination of pricing, PacifiCorp would be willing to provide pricing with only previously signed contracts incorporated in the potential QF queue and incorporating assumptions as of the time the contract is signed. The contract could include the right to terminate the contract within 30 days of receiving final pricing if it was inadequate to support development of their project. This would ensure that the impact of successive proposals is reflected in QF pricing and that projects which are not moving forward are removed in a timely manner.

Q. What do you recommend with regard to the potential QF queue?

A. The potential QF queue should continue to be used in the preparation of indicative avoided costs and the milestones identified in the QF Pricing Status Management Business Practices contained in Exhibit PAC/302 should be adopted.

CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I recommend the Commission take the following actions:

1. Move consideration of the policy issues associated with the PacifiCorp's updated RPS and non-RPS avoided cost price streams to a generic investigation proceeding, beginning with the workshops directed by the Commission at the conclusion of docket UM 1794;
2. Adopt PacifiCorp's proposed refinements to the PDDRR methodology used to calculate non-RPS avoided cost price streams.

Q. Does this conclude your July 2017 opening testimony?

A. Yes.