PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 13, 2018

VIA ELECTRONIC FILING

Steven V. King
Executive Director and Secretary
Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive S.W.
P.O. Box 47250
Olympia, WA 98504-7250

RE: Docket U-161024—Pacific Power & Light Company's Comments

In response to the Notice of Opportunity to File Written Comments issued by the Washington Utilities and Transportation Commission (Commission) March 16, 2018, Pacific Power & Light Company (Pacific Power), a division of PacifiCorp, submits these written comments.

I. BACKGROUND

In September 2016, the Commission initiated an inquiry into potential revisions to its rules related to the integrated resource plan (IRP) process and utility bidding processes. As part of this inquiry, the Commission is also examining whether to revise the rules that outline a utility's obligations under the Public Utility Regulatory Policies Act of 1978 (PURPA). After holding workshops and inviting comments on utility and stakeholder recommendations, the Commission asked the public to provide feedback on its draft PURPA rules by providing additional written comments and participating in a May 14, 2018 workshop.

Before discussing the Commission's draft rules in detail, PacifiCorp first offers a high-level overview of the Commission's implementation of PURPA since the statute's enactment in 1978, and observes that the draft rules are a marked departure from that history. The Commission certainly has broad authority to make sweeping changes to its PURPA policies should it choose to do so. But based on PacifiCorp's significant and varied experience with PURPA across several states, the Commission's proposed draft rules, if implemented as written, will fundamentally change the PURPA landscape in Washington by significantly altering avoided-cost pricing, as well as key provisions in power-purchase agreements (PPAs) and interconnection agreements. This will result in what this Commission has so aptly described as a "flood" of Washington PURPA projects, funded by Washington retail customers.

II. OVERVIEW OF WASHINGTON PURPA POLICY—A COMMITMENT TO CUSTOMER INDIFFERENCE

The Commission has a long history of prioritizing customer indifference in its implementation of PURPA. In one of its very first PURPA dockets, the Commission rejected a PURPA contract proposed by Avista, finding that the proposed price and contract structure did not adequately hold Avista's customers indifferent to the proposed purchase from the qualifying facility (QF).[1] In reviewing the still-new federal and state PURPA landscape, the Commission expressed support for QF development, but emphasized the importance of carefully scrutinizing avoided-cost prices, particularly during times of energy surplus, to "ensure that PURPA requirements do not unnecessarily burden ratepayers."[2]

The Commission's ratepayer concerns led to a number of PURPA decisions emphasizing the importance of customer indifference. Early on, for example, the Commission rejected a levelized cost structure for QF PPAs. The Commission noted the Federal Energy Regulatory Commission's (FERC) position that some level of mismatch between a QF's long-term contract price and a utility's avoided costs at the time of the QF purchase is acceptable and does not lead to a utility's retail customers subsidizing QFs because the mismatch will be in both directions and ultimately net out over time. In response, the Commission stated that it could not "accept that rationale on its face" because "[t]here is no empirical evidence that such a balance will finally be struck."[3] Finding nothing in the federal PURPA regulations or state PURPA rules requiring that a QF contract include levelized costs, the Commission held that the terms of a long-term QF contract should not add capacity costs to the payment until the point in the contract term when the utility projects a capacity need.[4] The Commission reasoned that a delayed capacity payment would "serve the multiple purposes of PURPA to encourage the development of cogeneration facilities, provide for the most efficient use of energy, conserve scarce fossil fuels to the extent applicable in the Pacific Northwest, and at the same time not encourage the development of excess capacity which must be paid by the ratepayers."[5]

While the Commission has refined its policies over time, it has not wavered from its original focus on the crucial importance of meeting PURPA's customer-indifference standard. In examining issues related to legally enforceable obligations (LEOs) in 1987, for example, the Commission found that it would have been "foolhardy" for Avista to make a preliminary offer to purchase the QF's power before negotiating certain important contractual terms, as the QF argued it should. "If [Avista] had taken such an action and then been found to have failed in its duty to protect the ratepayers, the staff and public counsel would be quick to charge

---

[1] *Washington Utilities, and Transportation Commission v. Washington Water Power Company*, 56 P.U.R. 4th 615 (1983).
[2] *Id*. at 623-24 ("The WUTC fully supports the basic purpose of PURPA in increasing the utilization of cogeneration. The WUTC believes that cogeneration is a necessary and integral part of this region's future energy development. The WUTC recognizes that cogeneration is included as an integral part of the Northwest Conservation and Electric Power Plan issued by the Northwest Power Planning Council. However, both PURPA and the WUTC require that application of the statute and regulations must result in an outcome which is just and reasonable to the electric consumer of the electric utility involved in the purchase of energy from the cogeneration facility. In implementing its regulations, FERC intended to provide the maximum incentive allowed by PURPA for the development of cogeneration facilities in order to decrease reliance on scarce fossil fuels such as oil and gas. In adopting the full avoided cost rule, FERC also anticipated that ratepayers in the nation would benefit from the more efficient use of energy. If the WUTC required the company to purchase capacity which it does not need, the logic of promoting efficient use of energy would be violated.").
[3] *Id*. at 625.
[4] *Id*. at 625-26.
[5] *Id*.

'imprudence.' Yet in this case, both the staff and public counsel seem to give ratepayer protection a second priority. This is not the purpose of PURPA."[6] The Commission continued:

> ***By its own terms, PURPA was meant to protect the ratepayers***. Avoided costs should be established to be no greater than that which the ratepayers would be expected to pay without PURPA. Minimizing the cost to the ratepayer involves more than setting a reasonable purchase price. The purchase agreement must be carefully drafted, with minimal ambiguity, and maximum security in the event of a default, or other inability to perform. Such security is of critical importance where a "levelized" contract of long term and high volume is involved.[7]

The Commission has also explicitly recognized avoided-cost pricing as a cornerstone of maintaining customer indifference. "Consistent with the goals of PURPA, ratepayers and utilities should remain indifferent to whether power is purchased from qualifying facilities or from other sources. In achieving this objective, the Commission will use the best forecasts and best assumptions possible to arrive at accurate estimates of avoided costs."[8] Cautioning against the customer-indifference risks presented by inflated avoided-cost prices, the Commission explained that it had "observed a troublesome pattern in the development of PURPA resources" stemming from a statute that encourages the development of numerous small generators driven by industrial by-products or renewable resources capable of operating economically at a utility's avoided-cost rate, but the actual proliferation of large fossil-fueled projects "virtually identical to the type of resource which a utility would be expected to build for itself."[9]

The Commission noted as a cautionary tale that the availability of a relatively high avoided cost price in California "brought about such a flood of PURPA projects that the state commission was forced to institute a bidding system to limit the number of projects the ratepayers would have to fund."[10] While the Commission found that a bidding system can be an effective tool, it determined "another solution to the problem is to set avoided costs at conservative levels likely to encourage only those types of projects which are truly in the public interest. The ratepayers should be provided a reasonable opportunity to avoid the burden of a costly thermal plant without assuming the risk of purchasing too much PURPA power at too high a cost."[11] Ultimately the Commission found: "***All of these risks and concerns demand that regulators err, if at all, on the side of reducing the present cost to ratepayers.***"[12]

---

[6] *Spokane Energy, Inc. v. The Washington Water Power Co.*, Cause No. U-86-114 at 2 (1987).
[7] *Id*. (emphasis added).
[8] *Washington Utilities and Transportation Commission v. Washington Water Power Company*, 83 P.U.R.4th 364 at 375 (1987).
[9] *Id*.
[10] *Id*.
[11] *Id*.
[12] *Id*. (emphasis added). The Commission also explained: "If the error factor is small there should be little risk that reasonable opportunities for economical PURPA resources will be lost. This type of balancing is very much in keeping with the least cost planning initiative which this Commission has taken."

This customer-indifference focus has remained at the heart of the Commission's PURPA policy for approximately 40 years, which means Washington has implemented PURPA in a way that is less impactful to customers than other western states and chosen instead to use other methods to encourage development of renewable energy resources.[13] The Commission has repeatedly championed its authority to choose which policies are paid for by its taxpayers or customers, as its state's policy-makers determine, finding likewise that Oregon's and California's renewable energy policies should be paid for by the taxpayers and customers of those states, as determined by their policy makers.[14]

In PacifiCorp's 2013 general rate case, the Commission rejected the company's proposal to include the costs associated with QF contracts in Oregon and California in west control area net power costs, rather than assigning on a situs basis. The impact of this decision was a disallowance of approximately $11 million on a Washington-allocated basis. The Commission chose to assume the output of the out-of-state QF PPAs was replaced by market purchases in setting PacifiCorp's Washington rates.[15] In reaching that decision, the Commission did not make any findings that the Oregon or California QF costs exceeded PacifiCorp's avoided costs or were imprudent. Rather, the Commission stated that as a policy matter, Washington was less supportive of PURPA than Oregon and California. The Commission disallowed the out-of-state QF PPAs based on the "significant financial impact on Washington state ratepayers due to the different QF policies in Oregon and California."[16]

Now, the Commission is looking to implement rules that appear to be even more favorable to QFs than any other state in which PacifiCorp serves customers—a radical departure from the Commission's history of PURPA implementation. Based on this enormous policy shift, PacifiCorp questions whether the Commission would also reconsider its decision to disallow $11 million of QF costs, particularly since Washington would become the most QF-friendly of any of PacifiCorp's six-state service territory if these draft rules are implemented.

The following chart summarizing the current QF requests for PPA indicative pricing from PacifiCorp highlights the differences in state implementation of PURPA thus far:

STATE	PROJECT	Megawatts (MW)
California	0	0
Idaho	0	0
Oregon	42	2,010
Utah	21	1,575
Washington	2	82
Wyoming	34	1,792
TOTAL	**98**	**5,458**

[13] *WUTC v. Pacific Power & Light Co.*, Docket No. UE-130043, Order 05 ¶ 111 (Dec. 4, 2013) ("Washington policy makers have relied less on PURPA and more on renewable portfolio standards and greater use of tax-related incentives to promote renewable energy development in this state.").
[14] *See, e.g., id*.
[15] *Id.* at 98.
[16] *Id.* at 113.

The Commission has many tools that can be used to ensure the customer-indifference standard is not violated. These include establishing the appropriate eligibility cap for standard rates and the appropriate maximum contract term, but the most critical component is accurately setting the avoided-cost prices. These other components are important, but if the prices are significantly higher than the company's true avoided costs, then customers cannot be indifferent to QFs as required by PURPA.

As noted above, based on PacifiCorp's significant and varied experience with PURPA across several states, the Commission's draft rules, if implemented as written, will fundamentally change the PURPA landscape in Washington, resulting in what this Commission described as a "flood" of Washington PURPA projects to be funded solely by Washington retail customers.

III. COMMENTS ON DRAFT RULES

A. Response to the Commission's Questions for Consideration

1. Is the proposed definition of *capacity*, as described in WAC 480-106-DDD, an appropriate definition for the purpose of this rule?

PacifiCorp has significant concerns with how the definition of capacity would be implemented under the proposed draft rules. While adequate on its face, the proposed definition of capacity is overly broad and is not suitable in certain applications. The word "capacity" is used 37 times in the informal draft rule. It is used to describe the amount of capacity supplied by a QF, in reference to design capacity, in reference to nameplate capacity, in reference to avoided capacity cost, and in reference to capacity additions. Additionally, the proposed draft rules do not accurately account for the role of relatively low-cost capacity options in the form of market purchases (also called front-office transactions) in PacifiCorp's IRP and therefore risks significantly over-estimating avoided costs.

PacifiCorp's IRP assesses the ability for specific types of resources to meet forecasted coincident system peak load while accounting for reserve requirements, which ensures reliable electric service for PacifiCorp customers. When used in reference to capacity additions and avoided capacity cost, it is important that the definition of capacity is aligned with how utilities characterize capacity in their IRPs. PacifiCorp's IRP distinguishes between a resource's "nameplate capacity" (i.e., maximum output) and its "capacity contribution." The capacity contribution is a measure of a resource's ability to supply capacity at times when capacity is most needed. For instance, variable resources, such as wind and solar, have a capacity contribution that is less than the nameplate capacity to account for the fact that these variable resources may not be generating at full output when capacity is most needed.

The primary objective of the IRP is to identify the best mix of resources to serve customers in the future. The best mix of resources is identified through analysis that measures cost and risk, and the least-cost, least-risk resource portfolio is defined as the "preferred portfolio." In the 2017 IRP, the mix of resources in the preferred portfolio included traditional thermal resource additions, renewable resources, demand-side management, and market purchases. It is the combined characteristics of all of the resources in the preferred portfolio that make it least-cost and least-risk.

FERC has recognized that a firm market price paid to QFs when a utility is resource sufficient includes an embedded capacity cost. Therefore, to the extent prices during the resource sufficiency period incorporate avoided market purchases, QFs are being compensated for capacity. The absence of a specific capacity payment during resource sufficiency periods is therefore not the same as denying a capacity payment when the QF allows the utility to avoid a capacity cost. Ascribing an incremental capacity payment for avoided market purchases is not aligned with how capacity from market purchases are accounted for in the IRP and will overstate avoided-cost prices.

Additionally, a utility's avoided costs are not static; they must be updated to account for changes in market and system conditions. As avoided costs are updated and QFs seek new contracts, the most current avoided-cost information should be applied to new contracts, consistent with the customer-indifference standard. Given that utilities are typically limited to contracting and hedging horizons of less than 36 months because of concerns about price risk, market liquidity, prudency, and other risk considerations, it would be harmful to customers to guarantee a never-ending capacity payment to a QF without accounting for the risk to utility customers.

PacifiCorp uses its latest official forward price curve (OFPC) to develop the most accurate and up-to-date avoided-cost prices possible. The OFPC takes into account forward prices of electricity from various market sources and includes a model-based forecast of prices for region-wide loads, resources, and market conditions. The OFPC, therefore, represents PacifiCorp's best and most complete projection of what it would pay in the market to secure delivery of firm power that is relied upon to satisfy PacifiCorp's capacity requirements.

2. WAC 480-106-GGG strengthens the relationship between a utility's integrated resource plan and the avoided cost rates available to qualifying facilities. Consequently, avoided cost rates calculated at the time a legally enforceable obligation is incurred will reflect the utility's own forecasts and plans for meeting anticipated demand through a combination of supply-side and demand-side resources over a specified future period. Please comment on the merits of strengthening the relationship between a utility's integrated resource plan and its avoided cost.

PacifiCorp generally does not oppose the stronger connection proposed between inputs and assumptions applied in the IRP process and setting avoided cost rates, as the analysis and tools in the IRP are the same as those PacifiCorp uses to make resource commitments to meet anticipated demand. However, PacifiCorp has several concerns with the proposal in WAC 480-106-GGG.

Inter-Jurisdictional Allocation Methodologies

Because PacifiCorp is a multi-state utility with a unique allocation methodology only used in Washington, it is unclear how the results of its IRP should be applied to avoided costs in Washington. This is particularly true since Washington has disallowed recovery of several types of resources that remain part of the PacifiCorp portfolio and its forward planning.

Avoided Capacity Costs

The IRP selects market purchases because they meet capacity needs and contribute to the least-cost, least-risk combination of resources selected to meet load-and-resource-balance needs. Forcing a utility to set avoided capacity costs based on the cost of a peaker unit that is not selected in an IRP as part of a least-cost portfolio of resources is arbitrary, unreasonable, and will overstate avoided-cost prices.

Link to Acknowledged IRP

The proposal in WAC 480-106-GGG specifies that avoided costs be based on estimates of cost and need in a utility's most recently acknowledged IRP, with limited exceptions. Because IRPs may not be acknowledged for more than a year after filing and are based on assumptions that are finalized months before the initial filing, once the IRP is acknowledged, it is already stale. For example, as of April 12, 2018, PacifiCorp's 2015 IRP remains its most recently acknowledged IRP in Washington, and it reflects a plan that is now more than 36 months out of date. Instead, using PacifiCorp's most recently *filed* IRP or IRP Update with known and measurable adjustments (*e.g.,* executed contracts) is more likely to represent its least-cost, least-risk plan at any given time. Certainly, a filed IRP is a more accurate representation of a utility's long-term plan in the interim than an acknowledged IRP that is out of date. In addition, to the extent the IRP is used as the basis for future capacity needs, that forecast should be updated to account for known and measurable changes, including executed contracts, whether QF or non-QF.

60-Day Notice

The draft proposal provides QFs a 60-day notice for avoided-cost pricing changes, during which a QF may execute a PPA (or otherwise establish a LEO) at current rates or wait and execute a PPA at the updated rate if it is higher. The draft proposal also sets a relatively high bar to revise avoided-cost pricing between annual filings. These elements appear to be an attempt to balance QF and utility interest in avoided-cost pricing, but this balance is not consistent with PURPA. Instead, the appropriate balance is between accurate avoided costs and administrative efficiency. Providing QFs the opportunity to pick the higher of two avoided-cost prices would not be consistent with the customer-indifference standard. Alternatively, the Commission could make the proposed rates effective immediately upon filing, but subject to refund for any corrections or revisions identified during the Commission's review. Additionally, a utility, or any interested party, should be able to propose modifications to avoided-cost prices at any time, and the moving party would bear the burden of proving to the Commission that a proceeding to consider a price change is appropriate under the circumstances.

Levelized Payments

PacifiCorp does not support the application of levelized payments, which effectively requires the utility to provide a financial service to QFs. Front-end-loaded payments provide a disincentive to long-term performance because project returns for the QF are front-end loaded. Non-levelized payments require QFs to provide more project equity up front to retain project financing, which is an incentive for the QF to manage its asset in a way that promotes consistent performance throughout the contract term.

Should the Commission retain its requirement for levelized payments, section (iii) does not provide sufficient clarity on methodology or obligations. For instance, PacifiCorp's 2017 IRP levelizes costs and benefits across the study period using an after-tax weighted average cost of capital of 6.57 percent. It is unclear whether this is consistent with a "utility's authorized rate of return" in the draft proposal. In addition, levelized payments that are higher than a utility's avoided cost in the early years of a contract represent a loan from customers to a QF that must be repaid with interest via purchases at less than avoided cost in the later years of a contract. As with any loan, performance assurances are necessary, for instance in the form of levelization security tied to the differential between levelized payments and the non-levelized avoided cost. Levelization security is separate and distinct from other security requirements, such as development and default security, which cover normal forms of performance assurances in the QF contract. The degree to which customers are indifferent between levelized and non-levelized avoided-cost streams is also a fair question with an answer that may be utility specific or change over time.

3. WAC 480-106-GGG(1)(a) requires a utility to file an avoided energy cost based on the utility's forecast of market prices. WAC 480-106-GGG(1)(b) requires the utility to determine the avoided capacity cost using the Proxy Unit method. When using the Proxy Unit method, one option is to set the avoided energy price based on the energy price of the proxy resource. Should the avoided energy price be based on the market forecast or the price of the energy used for the proxy resource?

The distinction between avoided capacity costs and avoided energy costs is largely arbitrary. Regardless of the methodologies used to calculate these costs, the combined total of these components should be no more than the cost of the resource it is avoiding to ensure customer indifference. Forward market purchases and QF purchases have significant differences, and there should be adjustments to account for these differences. Forward market purchases are firm products with fixed delivery profiles. QF purchases are unit contingent with forecasted but uncertain delivery profiles. These same issues are true with respect to any proxy resource.

The Proxy Unit methodology can produce a reasonable estimate of avoided costs if the proxy resource has a high capacity factor and the QF delivers a uniform level of output across the year. In this instance the Proxy Unit would almost never be dispatched down during low-price periods or taken offline during low-price months.

However, if the Proxy Unit is a combined cycle combustion turbine (CCCT) that is dispatched down during low-price portions of the day and taken offline during low-price months (or high-water years), the energy price of the proxy unit will overstate avoided costs, as QF deliveries during periods when the CCCT would be backed down or taken offline would be overstated. In addition, the value of dispatching the CCCT in response to market prices, including sub-hourly prices such as in the Energy Imbalance Market, or to count CCCT capacity toward a utility's ancillary service obligations is not accounted for in its energy price.

If the Proxy Unit is a simple cycle combustion turbine (SCCT), it would be expected to be dispatched relatively infrequently due to its relatively high heat rate. An energy price based on its operating costs would therefore significantly overstate avoided costs. However, even in this instance, market price would overstate avoided costs, as the SCCT provides value relative to market when it is called upon and provides additional value in the form of ancillary services.

To better account for the specific costs and benefits of proxy resources and QF resources, PacifiCorp uses its Partial Displacement Differential Revenue Requirement (PDDRR) methodology to calculate avoided costs in other jurisdictions. Under the PDDRR methodology, a proxy resource is identified as the next deferrable generating unit in the company's most recently filed IRP. Avoided fixed costs for that proxy resource include avoided capital costs expressed in dollars per kilowatt (kW) and accounting for the operating characteristics and payment factor identified in the IRP for that deferred proxy resource. The avoided fixed costs also includes non-fuel fixed and variable operation and maintenance costs associated with the deferred proxy resource as reported in the IRP. To convert the proxy plant capital cost, grossed-up for revenue requirement, to an annual cost per kW, the method uses the IRP resource payment factor as the basis for the real levelized annual cost of the present value of the investment and adds inflation annually thereafter. The non-fuel variable operation and maintenance costs are converted into an annual cost per kW, using the relevant reported capacity factors in the IRP, adjusted for inflation, and this amount is added to the annual avoided capital cost calculation. This produces avoided fixed costs that increase over time.

The PDDRR methodology also produces a forecast of avoided energy costs by simulating the hourly operation of the company's utility system using the Generation and Regulation Initiative Decision Tools (GRID) model, the same model used to forecast net power costs in rate cases. Two GRID runs are performed to calculate hourly avoided energy cost. The first run is the existing utility system plus the planned resources contained in the company's preferred portfolio in its most recent IRP or IRP update; the second run is the same as the first run with two exceptions: the operating characteristics of the proposed QF project are added with its energy dispatched at zero cost; and the capacity of the IRP resource is reduced by an amount equal to the capacity contribution of the QF project. The difference in production costs between the two runs is the avoided energy cost. The result accounts for the energy benefits of a QF as well as the lost energy benefits associated with the proxy resource.

The fundamental premise of the PDDRR methodology is that the company's IRP preferred portfolio is the least-cost, least-risk plan to reliably meet system load. While the GRID model can reasonably account for the differences in energy value between resources in two geographic locations, to maintain a consistent load-and-resource balance, it is important to maintain the total effective capacity contribution identified in the preferred portfolio, as this meets the system planning reserve margin assumed in the IRP. For that reason, a QF defers IRP resources based on equivalent capacity contributions.

In addition, QFs preferentially defer IRP resources of the same type, with wind deferring wind, solar deferring solar, and so on. Limiting deferral to QFs of the same type helps ensure reasonable alignment between the operating characteristics of a QF and the preferred portfolio resources it is assumed to defer, which in turn helps ensure that the least-cost, least-risk outcomes achieved by the preferred portfolio are maintained. When no renewable resources of the same type remain in the IRP preferred portfolio through a QF's proposed term, QFs are assumed to defer thermal resources from the preferred portfolio.

The PDDRR methodology also accounts for other signed and proposed resources. To the extent the company has already committed to purchase or acquire resources, they can no longer be considered deferrable, and it is no longer appropriate to assume their capacity costs are avoidable. Because substantial QF resources may be acquired in a short time frame, particularly if avoided cost prices are overstated, it is appropriate to ensure that customers are not obligated to pay multiple QFs for the same increment of capacity by ensuring that rules on LEOs and updates to indicative avoided cost pricing between an initial request and execution are consistent with customer indifference. For instance, PacifiCorp maintains a queue of QFs that are currently negotiating contracts and provides prices assuming prior-queued projects will be signed. Prices can be refreshed to account for projects that drop out of this pricing queue.

4. **WAC 480-106-GGG(1)(a) requires utilities to file an avoided energy cost on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year. Should the Commission also require the avoided energy cost to include hourly or blocks of hourly periods?**

For negotiated QF contracts, PacifiCorp typically requires on- and off-peak prices by month over the term of the contract. These prices are developed by accounting for the specific hourly generation profile of the proposed resource and PacifiCorp's avoided capacity and energy costs. While it may be more efficient for a QF avoided-cost price schedule to include seasonal on-peak and off-peak periods, developing prices specific to different resource types (*e.g.*, baseload, solar, wind) will best ensure that the prices accurately represent avoided costs. While PacifiCorp does not have a proposal for more granular pricing blocks at this time, it believes that the Commission should remain open to requests for changes to better align QF contracting with avoided costs without reopening the rulemaking process.

5. **WAC 480-106-GGG(2)(iii) discusses schedules of estimated avoided cost. Is discounting the capacity payment from the utility's year of need to the present day an appropriate way to represent the avoided costs of a resource the utility has identified a need for in the future? In balance, does it provide the required price signal for capacity? Does this subsection require additional rule language and specificity?**

Bringing the capacity payment forward from the year of actual need in the form of a discounted payment does not accurately capture the timing of the capacity need that would provide a distorted price signal for capacity. As discussed above, levelized payments inflate avoided-cost prices in the early years of the contracts and must be off-set by some form of levelization security to maintain the customer-indifference standard. The distortion in the capacity price signal will be exaggerated if utilities are forced to set avoided capacity costs based on the cost of a peaker unit that is not selected in an IRP as part of a least-cost portfolio of resources.

6. WAC 480-106-GGG(c) is intended to permit utilities to offer standard rates that take into account the differing qualities of various generation types, such as variations in capacity factors. Currently, the informal PURPA draft rules do not specify how a utility might identify these qualities and use them to calculate avoided capacity costs. Does this subsection provide enough specificity or is additional rule language needed?

a. No resource, including thermal generation, has a one hundred percent capacity factor. Should the rules require applying a calculation that compares the qualifying facility to the highest capacity factor resource? For example, if the highest capacity factor plant has a capacity factor of 90 percent, and the qualifying facility has a capacity factor of 30 percent, then the capacity credit to the qualifying facility is 30% ÷ 90% = 33%.

Notably, WAC 480-106-GGG(c) allows for differentiating avoided capacity costs based on QF type, but does not allow for differentiating avoided energy costs. As previously noted, capacity and energy costs are inextricably related, and energy costs are unlikely to be identical for resources with different output profiles, particularly when those energy costs are aggregated to limited time frames, such as seasonal, on-and-off-peak values.

As indicated in the recommendations above related to "filed" versus "acknowledged" IRPs, it is appropriate for avoided capacity values to be based on the methods used in the long-term plan, which identifies proxy resources and costs. The rules need not specify the methodology, as it is likely to vary by utility and over time. Proposals for deviations from the methodology in a filed IRP should be allowed, but with the barrier of demonstrating the result produces more accurate avoided costs in combination with all of the other assumptions drawn from the IRP.

7. Joint Recommendations – The discussion draft rules do not include any option or the requirement to transfer any renewable energy credits (RECs) generated by qualifying facilities. The Joint Recommendations propose that RECs should be included in the sale when the avoided costs used to determine a utility's offered standard rate are based on a resource that would also generate RECs. Would this arrangement be satisfactory for all parties? In the instance where standard rates are based on a resource that does not generate RECs, is there reason to permit, or to require, the utility to offer a tariff schedule to qualifying facilities, which include the avoided cost of RECs? This arrangement would enable smaller developers to sell RECs at a set price and avoid the challenge of navigating a complex market, mirroring the rationale that PURPA uses in compelling utilities to purchase of capacity and energy.

PacifiCorp already expressed its concerns with the approach that select parties took when developing their "Joint Recommendation." PacifiCorp appreciates the opportunity to comment on this recommendation here. When reviewing the "Joint Recommendation" it is critical to keep in mind that all Washington utilities are not similarly situated. Therefore, proposals that may be acceptable to Puget Sound Energy are highly problematic for PacifiCorp's customers. Certainly Puget Sound Energy does not represent all utilities in supporting these recommendations.

During the portion of a QF's contract in which it receives a capacity payment based on the costs of a renewable resource, PacifiCorp should be entitled to the RECs associated with the QF's output. No additional compensation should be paid for the RECs beyond the renewable-resource-based capacity payment.

Because many of the same characteristics that make small power producers eligible to make sales at avoided cost under PURPA also make the RECs they produce qualify for renewables portfolio standard (RPS) compliance, it is not unreasonable for the Commission to determine that all RECs produced by QFs are retained by the utility for the benefit of customers, with no incremental compensation. This is the policy in California, which further specifies that associated RECs may only be used for RPS compliance within California. This is also the policy in Wyoming, which does not have an RPS. Because customers are obligated to accept long-term QF purchases at avoided cost and lose the opportunity to access lower-cost alternatives at a later date, the incremental customer benefits of REC ownership can help ensure overall customer indifference.

To the extent the Commission opts not to allow QFs to retain RECs associated with their output, utilities should not be obligated to acquire RECs under a tariff schedule. To the extent the Commission finds small QFs are hindered in bringing their RECs to market, it should ensure that requests for proposals (RFPs) for RECs allow small QFs to participate. Small QFs could also agree to be paid amounts equivalent to the winning RECs proposals acquired through an RFP.

The justification for the joint proposal incorrectly assumes that PacifiCorp is acquiring renewable resources for RPS compliance. PacifiCorp's renewable-resource acquisitions included in the 2017 IRP preferred portfolio are not needed to meet an RPS compliance obligation—meaning that PacifiCorp would be acquiring the renewable resources even if they did not provide RECs that could be used to comply with any RPS. PacifiCorp has three different types of cost-effective renewable resources in its 2017 IRP preferred portfolio, and those resources are all cost-effective assuming zero RPS-compliance costs. The renewable resources in the 2017 IRP preferred portfolio provide capacity and energy at a cost that is less than the available non-renewable alternatives without even considering the RPS-compliance value associated with their RECs.

An additional consideration for REC ownership occurs when considering deferral of different types of resources. While PacifiCorp has not proposed assuming deferral in this manner under the PDDRR methodology, if a solar QF resource defers a wind resource on a capacity-contribution-equivalent basis, PacifiCorp will lose RECs because the wind resource would have generated more energy and produced more RECs than the solar QF resource. Therefore, if a solar QF resource defers a wind resource, RPS-compliance costs are higher and customers are not indifferent.

8. Joint Recommendations – If the Commission adopts the recommendation to require the inclusion of limited contract provisions to qualifying facilities of all sizes, should the rule specify contract provisions that utilities must offer?

The Commission should not, by rule, specify contract provisions that utilities must offer. Rather, a cleaner path to a final agreement with fewer disputes would result from the rules outlining basic requirements, procedures, and milestones for preparing standard and non-standard contracts in the tariffs or schedules and allowing negotiating flexibility between the utility and QF in the contract itself. PacifiCorp instead recommends that the Commission require that each QF contract be filed and approved by the Commission. Such a requirement would provide adequate safeguards and negate the need for standard terms because there will be sufficient Commission oversight.

PacifiCorp has a wide variety of experiences with different state commission rules regarding this topic. PacifiCorp has over 160 QF contracts across its six states totaling approximately 2,700 MW. The vintage of contracts range from the 1980s to contracts executed under current state commission requirements. Only one of PacifiCorp's six states—Oregon—has standard offer pro-forma contract templates for the QFs who have projects qualifying for the Oregon Standard Avoided Cost Prices schedule. Utah, Wyoming, and Idaho do not have a requirement for a pro-forma contract. Rather, the commissions in those states have developed basic requirements, procedures, and milestones for preparing standard and non-standard contracts with dispute resolution avenues that QFs can use if negotiations break down between utility and the QF. If Washington elects to require standard contracts, it will join Oregon as an outliner as compared to the rest of PacifiCorp's six-state service territory.

The pro-forma agreements were developed in Oregon in Docket No. UM 1129[17] and have only had minimal updates to the terms and conditions since that time with no flexibility to modify the agreement to the benefit or detriment of the utility, the QF, or customers. Over time, these terms may become outdated or obsolete, but it is very administratively challenging and time consuming to update these standard contract terms through highly litigated generic QF proceedings at the Public Utility Commission of Oregon.

Many of the smaller QFs may argue they need a pro-forma standard agreement because they are small and can afford little or no legal counsel. These claims are contrary to PacifiCorp's vast experiences contracting with QFs. PacifiCorp has found that the majority of QF developers in the standard-offer category are large regional and national developers with strong balance sheets and access to the same legal and technical firms as the big "sophisticated" developers.

[17] Docket No. UM 1129 was open for approximately four years –from 2004 to 2008.

Table 1—Summary of the QF power-purchase agreement approval process by state for PacifiCorp.

State	Standard QF	Non-standard QF
Idaho	PPAs executed by both parties and submitted to the Idaho Public Utilities Commission for approval.	PPAs executed by both parties and submitted to the Idaho Public Utilities Commission for approval
Utah	PPAs executed by both parties but not required to be filed.	PPAs executed by both parties and submitted to the Utah Public Service Commission for approval
Wyoming	PPAs executed by both parties but not required to be filed.	PPAs executed by both parties and filed with the Wyoming Public Service Commission for acknowledgement.
Oregon	PPAs executed by both parties and filed with Public Utility Commission of Oregon. Prices and pro forma standard offer contract templates pre-approved.	PPAs executed by both parties and filed with Public Utility Commission of Oregon
California	PPAs executed by both parties but not required to be filed.	PPAs executed by both parties but not required to be filed.
Washington	PPAs executed by both parties but not required to be filed.	

9. Joint Recommendations – Does the recommendation that each utility file and obtain Commission approval of its avoided cost rate methodology for qualifying facilities above the size threshold for standard rate eligibility impose an unnecessary burden on utilities, stakeholders, and the Commission? Should the avoided cost rate for larger qualifying facilities depend on facts and circumstances that cannot be easily accounted for by rule?

No, the recommendation that each utility file and obtain Commission approval of its avoided-cost pricing methodology does not impose an unnecessary burden on utilities, stakeholders, and the Commission. In fact, PacifiCorp recommends review and approval of utility-specific methodologies for all size QFs, not just large QFs. PacifiCorp's PDDRR methodology also produces the most accurate avoided costs to inform published avoided costs for QFs below the size threshold. It is impossible for a rule to fully account for factors relevant to avoided costs. As a result, to the extent changes are difficult to implement in a timely manner, avoided costs will be inaccurate in the interim. PacifiCorp supports Commission approval of all QF contracts in recognition that an approved methodology may not result in customer indifference despite accurately implementing prior Commission guidance. This is particularly important when viewed relative to the scrutiny of utility resource additions through the IRP process. Commission approval of QF contracts is reasonable, particularly if the contract term is extended to 15 years.

B. Additional Comments

1. Under 480-106-FFF(2), a utility must file a tariff schedule with standard rates for purchases from QFs with a design capacity of seven MW or less. Does PacifiCorp have concerns with this provision?

Yes. Under PURPA, customers must remain indifferent to or unaffected by QF contracts. Both avoided costs and other terms and conditions of PURPA contracts affect whether retail customers remain indifferent to the purchase of QF power. Requiring wind and solar QFs to negotiate individual agreements based on each project's true size and characteristics will result in efficiently sited, constructed, and priced QF development. The company's recommendations are intended to specifically send more accurate price signals to QFs—negotiated avoided-cost prices send more accurate price signals to QFs because they account for a multitude of factors that are not included in the calculation of standard prices, and reduced contract terms eliminate speculative forecasting. Adopting guidelines for negotiating QF contracts in addition to having a robust dispute resolution process provide backstops to ensure each party must include reasonable contract terms and rates.

PURPA expressly contemplates that standard rates and contract terms should apply to very small projects, or those under 100 kW, but states are permitted to increase this eligibility cap. Currently, the Commission's rules state that QFs of one MW or less qualify for the standard offer. [18]

PacifiCorp believes the Commission has adopted the appropriate eligibility cap for QFs to qualify for standard avoided cost prices. PacifiCorp has seen a flood of QF development in states with higher eligibility caps for standard avoided cost prices, particularly by sophisticated, well-financed out-of-state developers taking advantage of the higher cap to earn maximum returns for investors at the expense of PacifiCorp's customers. The standard eligibility cap provides a clear delineation for projects that are deemed to be small to minimize their transaction costs for securing a PPA with the utility. These projects are generally categorized as being developed by individuals or organizations with limited resources that do not have the corporate backing, financial wherewithal, or technical skills to handle significant administrative issues or cost. For example, as the eligibility cap increased over time to 10 MW in Oregon, PacifiCorp found itself negotiating with well-funded, experienced developers who have successfully developed multiple QF and renewable projects across the country, and hire some of the most skilled technical and legal firms in the country. It is clear that there has been a shift from the "mom & pop" developer to the well-staffed development firm where there is a direct correlation between the size of the QF project and the amount of resources that can be applied to the project. Additionally, a lower eligibility cap for standard avoided-cost prices is necessary to control improper disaggregation where a large project is broken up into multiple standard projects to secure standard offer prices and more favorable contract terms.

The desire to stimulate QF development should be balanced with the customer-indifference mandate so that customers do not pay more for QF power than for other resources. The primary

[18] WAC 480-107-095(2).

rationale for standard rates is to minimize transaction costs for small projects. Avoided-cost prices for larger projects should take individual operating characteristics into account.

In balancing these factors, the Commission should review and set the eligibility cap for standard avoided-cost prices to include only projects that may otherwise be unable to afford the transaction costs of negotiating an individualized purchase rate. Retaining the current eligibility cap for PacifiCorp would continue to encourage the development of additional community-scale QF resources across all resource types, while reducing the disaggregation of large single projects in multiple small projects. Further, the current cap is consistent with the transaction cost rationale for standard avoided-cost rates and reasonable contract terms. Any projects over the current cap would still receive avoided-cost prices. However, project specific prices would be calculated under PacifiCorp's proposed PDDRR methodology as described earlier.

2. PacifiCorp has concerns with what appears to be a levelization requirement under 480-106-GGG(1)(b).

Section (iii) does not provide sufficient clarity on the methodology or obligations associated with levelized payments. For instance, PacifiCorp's 2017 IRP levelizes costs and benefits across the study period using an after-tax weighted average cost of capital of 6.57 percent. It is unclear whether this is consistent with a "utility's authorized rate of return" in the draft proposal. In addition, levelized payments which are higher than a utility's avoided cost in the early years of a contract represent a loan from customers to a QF which must be repaid with interest via purchases at less than avoided cost in the later years of a contract. As with any loan, performance assurances are necessary, for instance in the form of levelization security tied to the differential between levelized payments and the non-levelized avoided cost. Levelization security is separate and distinct from other security requirements such as development and default security which cover normal forms of performance assurances in the QF contract. The degree to which customers are indifferent between levelized and non-levelized avoided cost streams is also a fair question with an answer that may be utility specific or vary over time. As such, this is an area in which the Commission's discretion is valuable. In light of the foregoing PacifiCorp believes it would be more appropriate for the PURPA rules to establish a pathway to levelized payments without being overly specific on the permissible methodologies or guaranteeing availability.

3. Under 480-106-GGG(2), a utility may file revised tariff schedule before its next annual filing only if either (a) the utility executes agreements with QFs for a combined capacity of 50 MW or more since it filed the tariff schedule of estimated avoided cost in effect; or (b) the utility's current forecast of market prices for power changes by 25 percent or more from the forecast used to support the tariff schedule of estimated avoided cost in effect. Why does this not offer sufficient protections against the inevitable flood of QFs in Washington if these draft rules are adopted?

This provision governing filing of revised tariff schedules will not protect customers. Informed by its experience with QF pricing requests across its six-state system, PacifiCorp is very concerned that if the informal draft rules are adopted, avoided-cost prices will be overstated, which will cause a flood of QFs that will quickly overwhelm the combined 50-MW threshold. Moreover, the combined 50-MW threshold, without appropriate protections, will provide an incentive for QFs to rush to execute PPAs with stale prices if they see an indication that prices may change.

The proposed 50-MW cap does not account for differences between utilities. A better cap would be tied to utility-specific requirements. Moreover, once the cap is reached, additional purchases under the tariff should be restricted to the FERC-required minimum of 100 kW for published rates until a new avoided-cost schedule is approved. Projects in excess of the FERC minimum would continue to be eligible for non-standard rates during the interim to meet the utility's must-purchase obligation under PURPA. These protections would be necessary to help protect Washington customers from the inevitable flood of QF projects in Washington if these draft rules are implemented.

4. Under 480-106-HHH(4)(a), the utility will be required to offer standard rates for a 15-year term for new QFs and 10 years for existing QFs. How will this harm customers?

There are numerous tools at the Commission's disposal to ensure that the customer-indifference standard is not violated, including contract term and eligibility cap. If the Commission's rules for pricing accurately captured the company's true avoided costs, then the term of the contract may be less important to maintain customer indifference. However, as discussed above, the current rules would lead to significantly higher avoided-cost prices that would violate the customer indifference standard, and this harm to customers would be exacerbated by the proposed 15-year term.

The current five-year fixed price contract term reasonably balances customer and QF interests by producing more accurate avoided-cost prices, particularly in today's market where avoided-cost prices are falling as a result of both market changes and technology changes. QF resources are not comparable to conventional resources, which are acquired only after a comprehensive public planning and procurement process. Rather, QFs are more akin to hedges, which, due to the risks inherent in hedging, do not extend beyond a three-year term without extensive Commission review. A shorter contract term also recognizes that the QF market is not subject to conventional market dynamics because of the must-buy obligation, and therefore the QF market is not self-regulating and requires Commission intervention to protect customers from runaway development.

Utility resource decisions are examined in a thorough and comprehensive public process that assesses the costs and risks associated with the company's options for meeting future load. QF resources are not subject to this level of review, or any other planning process. If a QF requests a contract, the company must oblige regardless of the need for the resource and with only limited consideration for how the resource fits into the company's resource planning process.

Additionally, utility resources are subject to the company's dispatch control. QFs, on the other hand, are must-take resources that the company cannot reject even when the QF contract price exceeds the company's marginal cost. Additionally, because the company cannot dispatch the

QF resource, it must be prepared at all times to transmit the QF output, even if the QF fails to generate as expected. This imposes further costs on customers that would not be incurred with a utility resource.

There is nothing inconsistent or otherwise ambiguous about requiring a utility to file a 20-year forecast of avoided-cost prices without entitling a QF to a 15-year fixed price contract. FERC has specifically explained that its filing requirement is intended to inform potential QF developers of forecasted prices, not guarantee fixed-price contract of a particular term.[19]

To implement PURPA, Congress "expressly directed [FERC], and not the states, to prescribe rules governing QF rates."[20] FERC adopted regulations reiterating the avoided-cost requirement. Section 292.304(a)(2) of FERC's regulations states unequivocally: "Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases."[21] When FERC's rules were challenged, the U.S. Supreme Court upheld the rules, concluding that PURPA "sets full avoided cost as the *maximum* rate that [FERC] may prescribe."[22] The states' role in PURPA is limited—Congress "gave the states responsibility *only* for 'implement[ing]' [FERC's] rules."[23] PacifiCorp acknowledges that FERC has previously expressed support for long-term standard contracts.[24] However, FERC's prior support for long-term forecasts of avoided-cost prices is no basis to conclude that PURPA requires long-term pricing guarantees.

Much of the opposition to the five-year term focuses on the claim that QFs will be unable to obtain financing if the contract term is shortened to three years and therefore a reduced term will inhibit QF development. However, this argument places the interests of QF developers ahead of the interests of customers. It is reasonable for developers, not customers, to bear the costs and risks of project financing, particularly given the sophisticated nature of the QF developers in today's market.

The "Joint Recommendation" asserts that QFs should have the right to select a commercial operation date three years from contract execution subject to certain requirements. This is coupled with a recommendation for a 15-year contract term. PacifiCorp has serious concerns with this recommendation and its potential harmful impact on customers. The three-year period between the time of execution and the commercial operation date will ensure that the utility will be paying significantly out-of-date prices by the time the QF achieves commercial operation, which will likely harm customers and run afoul of the customer-indifference standard.

[19] *See e.g.* Order No. 69 at 12,218.
[20] *Connecticut Light & Power Co.*, 70 F.E.R.C. ¶ 61,012, 61,027 (1995).
[21] 18 C.F.R. § 292.304(a)(2).
[22] *American Paper Institute, Inc. v. American Elec. Power Service Corp.*, 461 U.S. 402, 413, 103 S. Ct. 1921, 1928, 76 L. Ed. 2d 22 (1983) (emphasis added).
[23] *Connecticut Light & Power Co.*, 70 F.E.R.C. at 61,027 (emphasis in original); *Re So. Calif. Edison Co.*, 70 F.E.R.C. ¶ 61,215, 61,676-77 (1995) (emphasis in original).
[24] *See e.g.* Order No. 69 at 12,224.

5. Does PacifiCorp have comments on WAC 480-106-KKK?

Yes. This proposed rule includes proposed amendments to the regulations governing QF interconnections. PacifiCorp is primarily focused on the proposed changes to the Commission's existing provision on QF interconnection costs (WAC 480-107-125), shown below in redline against the current language:

> (1) Any costs of interconnection are the responsibility of the owner or operator of the ~~**generating**~~ **qualifying** facility entering into a power contract under this chapter. The utility must assess all reasonable interconnection and necessary system or network upgrade costs the utility incurs against a ~~**generating**~~ **qualifying** facility on a nondiscriminatory basis**, as described in a utility's interconnection tariff filed pursuant to WAC 480-108-080**.
>
> (2) The owner or operator of the ~~**generating**~~ **qualifying** facility must reimburse the utility for any reasonable interconnection costs the utility may incur. Such reimbursement shall be made, at the **qualifying facility's** ~~**utility's**~~ election:
>
> (a) At the time the utility invoices the owner or operator of the ~~**generating**~~ **qualifying** facility for interconnection costs incurred by the utility; or
>
> (b) Over an agreed period of time not greater than the length of any contract between the utility and the ~~**generating**~~ **qualifying** facility.

These changes fall into three basic categories: (1) clarifying that the interconnecting generator is a qualifying facility; (2) referencing the Washington distribution interconnection rules; and (3) allowing the QF, rather than the utility, to decide on the mechanism for the QF's payment of interconnection costs. PacifiCorp supports the first clarification but, as described below, strongly recommends the Commission reject the other two proposed changes.

Background regarding FERC's Regulations on QF Interconnection Cost Allocation

Allocation of QF interconnection costs is subject to a unique federal and state regulatory landscape. Interconnection service with a utility's transmission system is usually FERC-jurisdictional. But PURPA gives state regulatory authorities exclusive jurisdiction over QF interconnections with a utility's transmission system if the QF's entire output is sold to the directly interconnected utility.[25] FERC's PURPA regulations nevertheless provide some guidance in this area.

[25] *See, e.g., Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 62 FERC ¶ 61,128, *order on reh'g*, 64 FERC ¶ 61,139 at 61,991, *order on reh'g*, 65 FERC ¶ 1,081 (1993) (landmark order addressing various jurisdictional issues and reiterating previous FERC ruling that "the states have exclusive jurisdiction over direct interconnections between a QF and the public utility which purchases its power."); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at PP 813-14 (2003). FERC has also found that state-jurisdictional QF agreements do not need to be filed with FERC. *See, e.g., Florida Power & Light*, 133 FERC ¶ 61,121 at P 21 (2010) (holding that FERC "will exercise jurisdiction or require the filing of an interconnection agreement only if there is some manifestation of a QF's 'plan to sell' output to third parties.").

FERC's regulations on allocation of QF interconnection costs reflect state-commission jurisdiction, stating that QFs "shall be obligated to pay any interconnection costs which the State regulatory authority…may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics."[26] Regarding the QF's payment mechanism, the FERC regulations direct state commissions to "determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time."[27]

Washington's Existing Regulations Governing QF Interconnection Costs

The Commission's existing provision addressing QF interconnection costs (WAC 480-107-125) is largely modeled after FERC's PURPA regulations. In addition, in the context of developing non-QF interconnection rules, the Commission considered extensive stakeholder input on QF interconnection cost allocation issues.

In 2006, the Commission initiated an inquiry into, among other things, whether and how to amend its interconnection regulations (Chapter 480-108, Electric Companies—Interconnection with Electric Generators) in response to certain statutory directives in the Energy Policy Act of 2005.[28] The Commission asked parties to comment on whether standards governing distribution-level interconnections should also apply to QF interconnections.[29] In response, parties discussed in detail—both in written comments and during workshop discussions—the unique nature of QF interconnection cost allocation issues from a policy and jurisdictional perspective.[30]

PacifiCorp filed comments explaining, for example, that while it may be appropriate under certain circumstances for the costs associated with non-QF interconnecting generators subject to state-commission jurisdiction to be shifted from the generator to retail customers, cost-shifting is never appropriate for QF interconnections.[31] PacifiCorp discussed the unique limitations on a state's discretion to develop QF interconnection rules, noting that requiring a utility's retail customers to purchase QF output at avoided-cost rates *and* pay for system or other upgrades required to interconnect the QF would shift costs to retail customers in excess of the utility's avoided cost in violation of the customer-indifference standard.[32]

[26] 18 C.F.R. § 292.306(a) (2018).
[27] 18 C.F.R. § 292.306(b) (2018).
[28] *Notice of Opportunity to File Written Comments*, Docket UE-060649 (June 9, 2006).
[29] *In the Matter of Amending and Adopting Rules in WAC 480-108 Relating to Electric Companies—Interconnection With Electric Generators*, Docket UE-060649, General Order 545 at ¶ 18 (Sept. 27, 2007).
[30] *Standards for Interconnection to Electric Utility Delivery Systems*, Docket No. UE-060649, Comments of PacifiCorp at page 3 (Jan. 5, 2007) ("During the December 15 workshop, PacifiCorp observed that interconnection of Qualifying Facilities under PURPA is subject to certain restrictions that may not be present with regard to other types of generation facilities. WUTC staff has asked PacifiCorp to elaborate and we will attempt to do so here.").
[31] *Id*. at 3. Avista supported PacifiCorp's comments in this proceeding. *Standards for Interconnection to Electric Utility Delivery Systems*, Docket No. UE-060649, Comments of Avista at page 2 (Aug. 14, 2007).
[32] *Id*. at 3.

PacifiCorp also recognized that the QF interconnection cost allocation approach is different from the cost allocation rules applicable to FERC-jurisdictional interconnections—rules that require the generator to upfront fund the cost of system upgrades subject to later reimbursement through credits on the interconnection customer's transmission service bill.[33] PacifiCorp discussed how this departure from the federal policy is appropriate because allowing the QF interconnection customer to be reimbursed for system upgrades would violate the customer-indifference standard applicable to state-jurisdictional QF interconnections.[34]

After considering these issues, the Commission decided against any overlap between its distribution-interconnection rules and its QF-interconnection rules.[35] This is explicitly recognized in the distribution-interconnection rules as follows: "This chapter does not govern interconnection of, or electrical company services to, PURPA qualifying facilities pursuant to chapter 480-107 WAC."[36] As discussed in more detail below, the Commission should maintain this distinction in its revised PURPA rules.

The Draft PURPA Rules Ignore Federal Guidance and the Commission's Previous Decisions regarding QF Interconnection Cost Allocation Issues

The draft PURPA rules appear to stray from the federal guidance and the Commission's previous consideration of QF interconnection cost allocation issues. In particular, the draft rules propose to reference the Washington distribution-interconnection rules for purposes of QF interconnection costs. The draft provision on interconnection costs states that the utility must assess interconnection costs as described in the utility's interconnection tariff filed under a provision of the Commission's distribution interconnection rules (WAC-480-108-080).[37] A similar reference is included in the draft provision on "Obligations of the utility to qualifying facilities," which states that the obligation to pay for any interconnection costs will be determined in accordance with the provision on QF interconnection costs *and* the interconnection service tariffs filed under WAC-480-108-080.[38]

[33] *Id*. at 4.
[34] *Id*. at 4. In addition, from a practical standpoint, PacifiCorp noted that the federal transmission-service crediting mechanism would not work for QFs because QFs, unlike other types of interconnecting generators, are not *also* transmission customers of the utility. In other words, there would be no QF transmission-service invoice to which the utility could apply credits. *Id*.
[35] *In the Matter of Amending and Adopting Rules in WAC 480-108 Relating to Electric Companies—Interconnection With Electric Generators*, Docket UE-060649, General Order 545 at ¶ 29 (Sept. 27, 2007) (noting that PacifiCorp and Avista asked the Commission to clarify that the proposed rules do not govern the interconnection of PURPA qualifying facilities and explaining that "the intent of the rule was to state that all services to state that all services to qualifying facilities addressed by WAC 480-107, including interconnection, are governed by that chapter and not by WAC 480-108.").
[36] WAC 480-108-001(4).
[37] Draft PURPA rules, section 480-106-KKK [Formerly WAC 480-107-125], subpart (1).
[38] Draft PURPA rules, section 480-106-FFF [Formerly WAC 480-107-095], subpart (4) (relevant amendment redlined against the existing rule: "(4) A utility must make all the necessary interconnections with any qualifying facilities to accomplish purchases or sales under this section. The obligation to pay for any interconnection costs will be determined in accordance with WAC 480-**107-125**~~106-KKK~~ Interconnection costs **and the interconnection service tariffs filed under WAC 480-108-080**."

The draft rules propose to unravel this separation by referencing the Commission's distribution-interconnection tariff for QF cost allocation purposes, and the Commission should again reject that approach due to the inherent conflicts that still exist today between the policies underlying the two types of interconnection. In PacifiCorp's experience, the costs associated with a QF's interconnection, particularly if the QF chooses to site in a constrained area, can be astronomical and should not be borne by PacifiCorp's retail customers consistent with the customer-indifference standard. PacifiCorp recommends that the Commission eliminate the proposed distribution-interconnection tariff references from the draft PURPA rules for the same reasons it originally maintained explicit separation between the two sets of rules—to protect customers.

The draft rules also propose to allow the QF, rather than the utility, to decide on the mechanism for the QF's payment of interconnection costs. The two options are: (1) paying upfront (at the time of invoice); or (2) paying over an agreed period of time not to exceed the length of any contract between the QF and the utility. PacifiCorp's practice has been to elect, consistent with this provision, to require QF interconnection customers to pay interconnection costs upfront. This approach maintains customer indifference because PacifiCorp's retail customers are not forced to even *temporarily* pay for the cost of QF interconnections. In other words, if the Commission implements the draft rules as written and a QF elects to pay for the cost of its interconnection over a period of years, that means the utility's customers will fund the QF's interconnection upfront, presumably through an increase to the utility's transmission rate base paid for by all system users, subject to reimbursement from the QF over many years. The current rule that allows the *utility* to elect for interconnecting QFs to pay for the cost of their interconnection upfront, just like all other FERC-jurisdictional interconnection customers,[39] is the far superior approach and should not be modified to preserve customer indifference.

Please direct inquiries to Ariel Son, Regulatory Affairs Manager, at (503) 813-5410.

Sincerely,

/s/

Scott Bolton
Senior Vice President, External Affairs & Customer Solutions
Pacific Power & Light Company
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
(503) 813-7202
scott.bolton@pacificorp.com

[39] As noted above, QF generators are not later reimbursed through transmission credits like non-QF interconnecting generators subject to FERC's jurisdiction and the interconnection cost-allocation provisions of PacifiCorp's Open Access Transmission Tariff.