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Filed Via Web Portal

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

Re: Docket UE-161024: Comments of Puget Sound Energy in Response to Notice of Opportunity to File Written Comments on Public Utility Regulatory Policies Act, Obligations of the Utility to Qualifying Facilities, WAC 480-107-105

Dear Mr. King:

Puget Sound Energy ("PSE") appreciates the opportunity to respond to questions for consideration proposed by the Commission in its Notice of Opportunity to File Written Comments on the Public Utility Regulatory Policies Act ("PURPA"), and obligations of the utility to qualifying facilities in this docket ("Notice").

Introduction

PSE appreciates the Commission's willingness to revisit its rules, terms, conditions and practices surrounding PURPA, avoided costs and qualifying facilities ("QF") to ensure the market remains efficient and provides the appropriate information to all parties to make informed decisions. From PSE's perspective, the purpose of the various rules and processes being discussed here is to ensure that ratepayers do not overpay for resources, and utilities can act in the best interest of protecting ratepayers from decisions that lead to unjust, unreasonable or insufficient rates. In reviewing these rules, PSE encourages the Commission to ensure that any revisions do not deviate from the fundamental objective of protecting ratepayers under the existing regulatory rules and principles in Washington State. Ratepayers must be the ultimate beneficiaries of these processes and their benefits must be known and measureable as defined by existing statute. In general, the Commission should avoid creating overly-prescriptive methodologies or rules that would distract these processes from focusing on traditional ratepayer benefits in the future. The Commission has consistently made clear that the considerations of externalities, such as environmental benefits, are currently outside the Commission's purview and that the Commission's core duty is to set rates and any environmental objective, as laudable as it may be, does not imbue utility service with an environmental purpose.

The Notice states that the "Commission's rules governing PURPA avoided cost rates are broad and leave considerable room for a number methodological approaches." Below PSE proposes guidance in a few areas that may be helpful but encourages the Commission to view its flexibility in addressing PURPA estimated avoided cost rates as a positive. Any prescriptive guidance should ensure that all parties with an interest in these rules, terms, conditions and practices are driven by the fundamental objective of protecting and creating traditional benefits for ratepayers.

A. Avoided cost methodology

1. What is the appropriate avoided cost methodology for calculating QF energy and capacity rates? A brief review of commonly cited literature identifies five methodologies:

- **Proxy Unit**
- **Peaker Method**
- **Difference in Revenue Requirement**
- **Market-Based Pricing**
- **Competitive Bidding**

PSE Response

The Notice identifies five established avoided cost methodologies for calculating QF energy and capacity rates, each of which is briefly summarized below:

1. Proxy Unit Methodology: This proxy unit method assumes that sales by a QF allows a utility to defer or delay a future generating unit (i.e., the proxy unit) and sets the utility's avoided costs based on the projected capacity and energy costs of this proxy unit. The proxy unit's projected fixed costs set the avoided capacity cost, and the proxy unit's projected variable costs set the avoided energy cost. The capacity costs are annualized over the expected life of the QF to yield an annual capacity cost per kW. A fixed charge rate reflecting, among other factors, the utility's debt and equity costs and tax burden often is used to annualize the capacity costs.

2. Peaker Method: The peaker method establishes avoided capacity cost using the utility's least-cost capacity option (usually a combustion turbine) and avoided

energy cost using marginal energy costs, forecasted over the lifetime of the contract. This method assumes that the QF output displaces the marginal, or most expensive, generation source on the utility's system at any given time for the duration of the contract. In other words, the peaker method assumes that a utility's avoided cost is the utility's projected system marginal cost of energy in any given hour plus the fixed cost of a peaking unit.

3. Differential Revenue Requirement Method: The differential revenue requirement method simply establishes avoided costs as the present value of the difference in the utility's overall generation costs (fixed and operational) with and without the QF.

4. Market-Based Pricing Method: The market-based pricing method establishes avoided energy costs as equal to projected energy costs and allows for the determination of an avoided cost even in the case of sufficient system capacity.

5. Competitive Bidding Method: The competitive bidding establishes avoided costs as equal to capacity and energy prices identified in a competitive bidding framework.

Of the methods listed above, PSE generally finds that the competitive bidding and the market-based pricing methodologies provide the most protection for ratepayers. Utilities should have the flexibility to use either the competitive bidding or the market-based pricing methodologies depending on the circumstances.

Competitive bidding provides the most accurate pricing but is not always worth the time and expense. The utility can rely on the outcome of a competitive bidding process for a few years. If a utility hasn't conducted a competitive bidding process for a few years, the next best method to calculating QF energy and capacity rates is market-based pricing. Market-based forecasting is particularly important for establishing capacity rates, as no forward capacity markets exist in the Pacific Northwest. QF Energy pricing could rely on different certain markets (or a combination) such as Mid-C, EIM, or others. When making its schedule of estimated avoided cost filing, the utility should be clear which methodology was used.

PSE views the proxy unit, peaker method, and difference in revenue requirement methodologies as outdated methodologies from the era of administratively-determined avoided costs of the early and mid-1980s that was largely displaced by the use of competitive bidding to establish avoided costs in the late 1980s. These three methodologies are critically dependent on underlying assumptions about fuel costs, demand growth, financing costs, labor and material costs, and permitting and siting costs, among other factors. These models are all prone to forecast error regardless of the method used. For example, avoided costs established in the mid-1980s significantly erred, and the impact on customers turned out to be very large and positive, i.e., with projected long-run avoided costs far in excess of realized avoided costs. These errors resulted from fuel prices that were overly pessimistic and resulted in an overdevelopment of gas-fired QFs due, in part, to the inflated avoided costs developed under these methodologies.

Starting in the late 1980s, Washington State, along with many other states, replaced or supplemented the administrative determinations of avoided cost with requests for proposals or bidding mechanisms. These competitive-bidding mechanisms were adopted, in part, to find the most economical QFs to fill the utility's energy and capacity needs. To determine which QFs should receive long-term contracts with the utility, competitive procurement processes rank interested QFs in terms of price and other criteria. Given the difficulties associated with administrative determinations of avoided cost, competitive bidding appeared to be a more efficient way to encourage QF electricity supply that is better matched to requirements of the utility.

Finally, PSE understands this question to be in the context of WAC 480-107-055 (Schedules of estimated avoided cost) because it is WAC 480-107-055 that outlines what the schedules of estimated avoided cost are to be based upon (WAC 480-107-105 neither uses the terms avoided cost nor schedules of estimated avoided cost). It is important to note that the schedule of estimated avoided cost provides only general information to potential bidders about the costs of new power supplies. It does not provide a guaranteed contract price for electricity. WAC 480-107-055 outlines several sources of that estimated avoided costs can be based upon in sub-section (2), these include:

(a) The most recent project proposals received pursuant to an RFP issued under these rules;

(b) Estimates included in the utility's current integrated resource plan filed pursuant to WAC 480-100-238;

(c) The results of the utility's most recent bidding process; and

(d) Current projected market prices for power.

PSE believes that these sources for estimated avoided costs for energy and capacity are appropriate, but the Commission should not foreclose its ability to add additional sources to the list in WAC 480-107-055(2).

2. Are there multiple methodologies that may be appropriate for calculating the energy and capacity payments, depending on its circumstances? If so, what criteria should the Commission use to identify the most appropriate methodology for a specific utility, at a specific point in time?

PSE Response

As stated above, PSE generally finds competitive bidding and market-based pricing methodologies have provided the most protection for ratepayers, while providing the proper price signals for QF development. The competitive bidding methodology is the preferred methodology for PSE during periods of capacity need because such methodology most effectively and efficiently identifies the then-existing costs of capacity and energy in the marketplace. The competitive bidding methodology appropriately accomplishes the goals of PURPA by (i) encouraging QF development in identifying the avoided costs of capacity and energy and (ii) protecting customers by ensuring that the avoided costs paid to QFs do not exceed the then-existing costs of capacity and energy in the marketplace.

During periods of capacity sufficiency (i.e., the utility is surplus capacity for the foreseeable future), the competitive bidding methodology may not be appropriate because a utility may not issue requests for proposals frequently enough to identify costs of capacity and energy in the marketplace. Therefore, the market-based pricing methodology is a more appropriate methodology if the utility has not issued a request for proposal within a reasonable period of time and the avoided costs from the most recent request for proposal have likely become stale. The Commission could seek to identify the appropriate length of time before a utility can no longer rely on its previous competitive bidding process and must rely on either a new bidding process or market-based forecast for its next filing.

In sum, PSE finds that the competitive bidding and market-based pricing methodologies provide the most appropriate balance between ratepayer protection and providing proper price signals for QF development. Whereas the competitive bidding generally provides the most accurate capacity and energy avoided costs through a market-based solution, the market information identified in the competitive bidding processes does go stale if requests for proposals are not frequently issued. In such cases, the market-based pricing methodology is a preferred methodology over any of the proxy unit, peaker method, or difference in revenue requirement methodologies, which are often relics of the administratively-developed avoided costs that predated avoided costs determined by competitive bidding processes.

3. Is it appropriate for a utility to calculate separate avoided capacity rates based on short-run and long-run resource requirements?

<u>PSE Response</u>

Yes, it is appropriate for a utility to calculate separate estimated avoided capacity costs based on short-run and long-run resource requirements. The capacity avoided cost should reflect the utility's need for capacity at that moment in time. Capacity values will change based on whether the utility expects to be long or short, which will in turn affect the market value of the capacity for that specific utility. During periods of utility capacity surpluses, the avoided capacity cost could either reflect (i) the near-term capacity costs of the utility (i.e., zero) or (ii) longer-term capacity costs of the utility (i.e., the present value of deferred future capacity from a QF). The former balances the competing considerations in favor of the impact on consumers, whereas the latter balances the competing considerations in favor of QF development. Prior orders indicated that the Commission has erred on the side of consumer protection:

> Federal Energy Regulatory Commission did recognize the potential for purchase obligations during a time of surplus. In further explanation of the utility's obligation to purchase from qualifying facilities, FERC stated as follows:
>
> > 'A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which utility can use to meet its total system load. 45 Federal Register 12219 (Feb. 25, 1980).'
>
> This means that the value of additional capacity may well be zero if the utility already has surplus capacity.
>
> 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.[1]

The current Commission may err on the side of QF development or may wish to strike a balance between the two goals of PURPA. The Commission should signal in this docket the appropriate balance between ratepayer protection and incentives to promote QF development so that utilities can reflect this balance in their estimated capacity avoided costs during periods of capacity sufficiency.

Another issue that the Commission may wish to consider in this docket is the possibility of establishing estimated avoided capacity costs based on location. For example, PSE serves load within Kittitas County. This load is located on the east side of the Cascade Mountains, relatively

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[1] *WUTC v. Wash. Water Power Co.*, Cause No. U-83-14, Second Supplemental Order (Nov. 9, 1983).

isolated from PSE's other loads on the west side of the Cascade Mountains. Due to the relatively small load in Kittitas County and the limited transmission capacity across the Cascade Mountains, the value of capacity to PSE in Kittitas County may be less than the value of capacity to PSE in areas with large loads, such as King County. Indeed, if the penetration of QF projects in Kittitas County were to exceed the relatively small loads in such county and PSE lacked sufficient transmission to get that QF power to loads west of the Cascade Mountains, then PSE may have no choice but to sell that QF power in markets east of the Cascade Mountains. Establishing differing capacity avoided costs based upon location could reduce this result by sending appropriate price signals and encouraging QF development in those locations with the greatest capacity need of the utility.

PSE encourages the Commission not to be overly-prescriptive with respect to resource requirements in the calculation of estimated avoided capacity costs. The elements included in the capacity costs are intended to meet the utility's need. Mandating requirements in the capacity avoided cost methodology reduces the flexibility a utility may have to focus on generating maximum benefits to customers. Depending on the circumstance, elements such as locational or environmental benefits are not always positive numbers and mandating them for a methodology in a rule, could lead to negative pricing in the market, even though a utility still shows a capacity need. PSE urges caution from the Commission in attempting to be overly-prescriptive in this rule, and instead encourages flexibility to focus on balancing ratepayer protection and providing proper price signals for QF development.

4. Should avoided costs be separated to reflect each type of resource's capacity value through a peak credit, Effective Load Carrying Capability, or some other calculation?

PSE Response

Yes, avoided costs should be separated to reflect each type of resource's capacity value through a peak credit, Effective Load Carrying Capability, or some other calculation. A methodology, such as the Effective Load Carrying Capability, more accurately values of the capacity of a variety of differing generation types, such as intermittent QFs. The Effective Load Carrying Capability recognizes the historical availability of the generation type during on-peak periods. Effective Load Carrying Capability estimates are produced for most new generation types based on system averages. After a period of actual generation characteristics have been analyzed, individual units are assigned an Effective Load Carrying Capability. The Effective Load Carrying Capability, which is a ratio, is multiplied by the yearly capacity value to accurately account for actual availability and is especially critical for intermittent resources such as solar and wind QFs. Another concept the Commission could consider further with respect separating avoided capacity costs is dispatchability. The schedules of estimated avoided costs for energy and capacity for QFs could be distinguished between those resources that are dispatchable by the utility and those that are not dispatchable by the utility, consistent with RCW 19.280.070.

B. Standard Practices

1. What should be the maximum design capacity of a facility to qualify for the standard offer? Should the Commission differentiate between types of resources for determining the maximum design capacity of a facility to qualify for a standard contract?

PSE Response

PSE's maximum design capacity for a facility to qualify for the standard offer is 5 MW. From PSE' perspective, if a facility is larger than 5 MW it should no longer qualify for the standard offer and be able to bid into PSE's solicitation process, under WAC 480-107-015.

PSE understands this question to be in the context of WAC 480-107-095, Obligations of utility to qualifying facilities, since it is WAC 480-107-095 that states that a utility must file standard tariff for purchases from qualifying facilities. PSE understands the term 'standard offer' to mean "standard tariff" schedule (e.g. PSE's Schedule 91), consistent with WAC 480-107-095. It is important to note that the standard tariff schedule may be based upon market prices and that they do not exceed the utility's estimated avoided costs from WAC 480-107-055. PSE understands the term "standard contract" to mean a Power Purchase Agreement (e.g. PSE's Schedule 91, Attachment "A" Agreement). PSE standard tariff schedule, i.e. Schedule 91, specifies the maximum capacity at five MW or less.

2. For the purpose of setting the maximum design capacity of a facility to qualify for a standard contract, is it necessary for the Commission to set a minimum distance between QFs belonging to the same owner? If so, what is the appropriate distance or test for determining a minimum distance? Should the Commission set different minimum distance requirements based on the type of QF resource?

PSE Response

For purposes of calculating a qualifying facility's net capacity, FERC regulations provide that generating facilities are considered together as a single qualifying facility if they are located within one mile of each other, use the same energy resource, and are owned by the same persons or their affiliates. FERC has held that its regulation defining generating facilities as separate qualifying facilities if more than one mile apart constitutes a safe harbor upon which developers can rely. While the developer can rebut the one mile presumption under certain circumstances to establish separate qualifying facilities that are less than one mile apart, the separate qualifying facility status of generating facilities more than one mile apart is fixed by FERC rule.[2]

PSE notes that this safe harbor may be an issue addressed by FERC in the ongoing technical conferences in Implementation Issues Under the Public Utility Regulatory Act of 1978, FERC Docket AD16-16. PSE is currently monitoring the outcome of these FERC technical conferences and encourages the Commission to follow FERC guidelines with respect to minimum distances between QFs belonging to the same owner for the purpose of setting the maximum design capacity of a facility to qualify for a standard contract.

3. If the Commission were to specify the term length of a standard offer power purchase agreement, how should it best balance the preference of project developers for longer term agreements to mitigate their risks against the uncertainty that the avoided cost rates in effect at the time will accurately reflect the true avoided cost to the utility in the future? Should the Commission differentiate standard contract lengths based on the type of resource?

PSE Response

If the Commission were to specify the term length of a standard offer power purchase agreement, the Commission should seek to strike the most appropriate balance between ratepayer protection and providing proper price signals for QF development. PSE appreciates developers' desires for longer-term contracts to increase the ability of the developer to finance the QF project. Indeed, PSE's tariff schedule has tried to accommodate developers in this regard by offering up to 16-year terms in recent years. Although a longer-term contract may provide developers more certainty, it also increases the probability that the avoided cost-based rate provided in the contract will not reflect the utility's actual avoided cost over the entire length of the contract. This could make the rate paid for QF generation unjust and unreasonable to utility ratepayers. One concept the Commission could further explore is building a discount into the term length. In other words, ratepayers assume more risk associated with a longer-term contract, and the contract could reflect that risk through a discount.

It should be noted for historical reference that the offered rates for purchased energy under PSE's Schedule 91 have had various terms for fixed priced rates over the years including periods with no fixed price rates. From 1982 to 2001, PSE's Schedule 91 offered a fixed price for the duration of one year. From 2001 to 2007 no fixed prices were offered for any term and PSE offered two calculated rate options: 1) Production Proxy Price; and 2) Market price. From the 2007 to 2017 PSE continued to offer the two calculated rate options (i.e. Production Proxy Price and Market price), but also added a Fixed Price. Currently, for calendar year 2017 the term of the Fixed Price is 16 years.

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[2] *See Northern Laramie Range Alliance*, 138 FERC ¶ 61,171, *reh'g denied*, 139 FERC ¶ 61,190 at PP 22-26 (2012).

4. Should the Commission specify in rule the point in the standard offer contract process where a utility has a legally enforceable obligation to purchase a facility's output?

PSE Response

Yes, the Commission should specify in rule the point in the standard offer contract process where a utility has a legally enforceable obligation to purchase a facility's output. Under section 292.304(d) of FERC's regulations, a QF has the unconditional right to choose whether to sell its power "as available" or pursuant to a legally enforceable obligation at a forecasted avoided cost rate determined, at the QF's option, either at the time of delivery or at the time that the obligation is incurred. 18 C.F.R. § 292.304(d). In *JD Wind 1, LLC*,[3] FERC indicated that the establishment of a legally enforceable obligation turns on the QF's commitment

> [A] QF has the option to commit itself to sell all or part of its electric output to an electric utility ... Accordingly, a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.[4]

Although FERC has made clear that public service commissions, such as this Commission, may not establish a legally enforceable obligation standard that requires the execution of a power purchase agreement or interconnection agreement,[5] FERC gives deference to the states to determine the date on which a legally enforceable obligation is incurred.[6] The precedent of this Commission with respect to legally enforceable obligations is thin. In *Wheelabrator Environmental Systems, Inc.*,[7] the Commission determined that Puget Sound Power & Light Company (a predecessor company of PSE) was not under a legally enforceable obligation because the proposed QF was not sufficiently "available" because it had not committed to a particular site or completion date, financing for the project was in doubt, and environmental concerns were unresolved:

> Therefore, the first issue (and the dispositive one) is whether the Wheelabrator proposal is truly an "available" resource. We must conclude that it is not. From the stipulated record, it is evident that Pierce County itself is not

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3 *JD Wind 1, LLC*, 129 FERC ¶ 61,148 (2009), *reh'g denied*, 130 FERC ¶ 61,127 (2010).

4 *JD Wind 1, LLC*, 129 FERC ¶ 61,148, at P 25.

5 *See generally FLS Energy, Inc., et al.*, 157 FERC ¶ 61211 (2016).

6 *See West Penn Power Co.*, 71 FERC ¶ 61,153 (1995).

7 *Wheelabrator Envtl. Sys., Inc.*, First Supplemental Order, Docket No. U-89-3043-F (1989).

committed to a particular site or completion date. Financing is in doubt. Environmental concerns remain unresolved.[8]

PSE has used this statement in determining whether a legally enforceable obligation exists and requires proposed QFs to provide evidence regarding a project's site location, financing, schedule, and permitting in evaluating whether the resource is an "available" resource and a legally enforceable obligation exists. If the Commission were to specify in rule the point in the standard offer contract process where a utility has a legally enforceable obligation to purchase a facility's output, such a rule would provide certainty and clarity for both the QF and the utility.

5. Should the rates and the model standard offer agreements be disaggregated into separate tariffs?

PSE Response

It is unclear to PSE what is intended by the question. PSE believes that its current practice through it standard tariff, i.e. Schedule 91, accomplishes this goal. PSE's Schedule 91 has a tariff schedule ('standard tariff" noted in WAC 480-107-095) that contains three price offers for QF's: 1) Production Proxy Price; 2) Market Price; and 3) Fixed Price. It also includes the model standard offer contract as Attachment "A" Power Purchase Agreement. For PSE, the model standard offer is for five MWs or less and the Fixed Price rate for the model standard offer agreement is not the same as avoided energy costs. Indeed, the Schedule 91 rate (i) includes adjustments to the avoided energy cost to reflect avoided capacity, deferred transmission and distribution investment, and line losses and (ii) reduces the resulting price by three percent for contingency reserves and by five percent for power balancing related costs.

Please contact Nate Hill at (425) 457-5524 or nate.hill@pse.com for additional information or questions regarding this filing. If you have any other questions, please contact me at (425) 456-2110.

Sincerely,
Nate Hill, Regulatory Initiatives Manager

for
Ken Johnson
Director, State Regulatory Affairs

cc: Lisa Gafken, Public Counsel
Sheree Strom Carson, Perkins Coie

[8] *Id.*