

**BEFORE THE WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION**

**UE-161024**

In the Matter of	)	
	)	
Rulemaking for Integrated Resource	)	
Planning, WAC 480-100-238, WAC 480-90-	)	
238, and WAC 480-107	)	
	)	NEWSUN ENERGY LLC
RE: Public Utility Regulatory Policies Act,	)	
Obligations of the Utility to Qualifying	)	
Facilities, WAC 480-107-105.	)	
Docket U-161024	)	
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**I. INTRODUCTION**

1. NewSun Energy LLC (“NewSun”) submits these comments regarding the Washington Utilities and Transportation Commission’s (the “Commission’s” or “WUTC’s”) rulemaking to examine whether the Commission’s rules related to the integrated resource plan (“IRP”) process, energy storage, requests for proposals (“RFP”), avoided costs, transmission and distribution planning, and flexible resource modeling require an update to reflect recent trends in the energy industry. In particular, NewSun is responding to the Commission’s Notice of March 20, 2017 (the “Notice”) to consider whether revisions are necessary to rules in WAC 480-107 that outline a utility’s obligation to a PURPA qualifying facility (“QF”).
2. NewSun is a developer of renewable and energy storage projects across the US, including opportunities to provide energy to utilities in the State of Washington. In the Commission’s Notice, several questions were presented to solicit stakeholder feedback and this submission will address each question in order.

3. A. **Avoided cost methodology:**

**Commission Q:** *“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, and Competitive Bidding.”*

Any avoided cost methodology should:

I) Incorporate all the attributes required under PURPA Section 210 requirements for avoided costs, including avoided energy, capacity, transmission, O&M, and any other costs projected for avoidance by the purchasing utility as a result of the power generation by the QF, as well as costs avoided which would have been incurred in order to comply with applicable state policies and regulations; for example, environmental attributes, renewable mandates, emission reductions and greenhouse gases.

II) Look at cost projections for over time periods consistent with 1) the term length requirements under PURPA which require long-term power purchase agreements of term sufficient to allow for the financing of the new generation facility (see FERC “Allco” 2016 ruling); and 2) in the case of capacity avoidance, reflects (a) the equivalent term of the asset life of the generation capacity avoided by the QF and (b) the incrementally increasing value to the ratepayer of deferring such prospectively rate-based generation assets for longer terms (i.e. avoided for 30 years is more valuable to the ratepayer than 20 years, which should be reflected in pricing made available to QFs for commensurate terms).

III) Incorporate utilities’ respective IRP generation asset plans into the calculation of when additional capacity avoidance might occur. For example, if a utility is projecting to build a new CT in year 202x, then the pricing schedule available to the QF which avoids the need for such new rate-based generation should incorporate the avoided cost; similarly, if a

renewable portfolio standard stair-steps up in a given year, the projected cost of new generation to meet that state mandate should be reflected in the avoided cost pricing.

IV) The method implemented and required by the state should provide for complete transparency of assumptions and inputs by utilities, so there is an opportunity for public scrutiny of the accuracy and applicability.

VI) Provide for predictability as to when rates (and if applicable methodology) can and will change, so as to provide visibility and a stable investment environment (to allow for developers to bring competitive options to the state, which is undermined in absence of such policy outlook stability).

V) Of the methods listed, the Proxy method as implemented in Oregon successfully implements these objectives.

**Commission Q: “*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?*”**

The Commission should define a clear single methodology in order to prevent gaming by utilities as to which rates the utility might offer each individual QF in order to discourage such prospective QF(s). Certainty in the market is required in order for developers to invest in the development assets required to bring QF projects to the market for the benefit of the ratepayers, which cannot be achieved if methodologies can shift, particularly at utility discretion.

**Commission Q:** *“Is it appropriate for a utility to calculate separate avoided capacity rates based on short-run and long-run resource requirements?”*

Yes. Short run and long-run resource requirements are often met via differing solutions. Short run avoided capacity rates often do not reflect the costs of producing or procuring from a generating resource that will be deployed over the long term. A new resource, by definition, will reflect the competitive long-run cost of new capacity.

**Commission Q:** *“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?”*

Yes, this is reasonable and the Effective Load Carrying Capability methodology is an appropriate means. The policy framework surrounding this should provide public visibility regarding the methods and assumptions to avoid utilities gaming such methods to discount actual contributions by certain resource types. If this is implemented through a volumetric rate structure, the Commission should take care to ensure that capacity value is embedded properly in such rates. As, for example in Oregon’s implementation, discussed in OPUC Order 16-174.

#### 4. B. Standard Practices

**Commission Q:** *“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?”*

The more important question pertaining to capacity sizing of standard offer contracts is not necessarily what the maximum size should be (with exceptions in the cases of particularly small utilities), but rather ensuring a maximum contract size is sufficiently large to allow QF power generation development at sufficient scales to bring the ratepayer the benefit of the

mature technology, while also not unnecessarily burdening smaller projects with disproportionately high fixed costs and financing costs. If the avoided cost methodology properly reflects actual costs avoided, the ratepayer should be indifferent to the project sizes being larger. Conversely, the ratepayer may actually be harmed by a cap on capacity which is too small, as this may prevent QFs from being successfully developed or economical, due to the burden of such costs on smaller projects, thus denying the ratepayer the opportunity to (i) benefit from efficiencies of scale, and (ii) avoid having new generation be rate-based at their long-term expense. Indeed larger projects may more efficiently accomplish societal goals, such as those in state renewable mandates and carbon policy, and motivated increase entrepreneurial activity to bring such solutions to the state and its ratepayers.

Maximum contract size should not be less than 20 MW in order to ensure that such financing costs are not unduly burdensome to such projects. A larger cap, such as 80 MW (consistent with the FERC maximum eligibility for SPP QFs) would bring the benefit of supporting QF development on larger voltage transmission lines, and thus effectively expand the market of competitive options which might benefit the ratepayer and achievement of state policy goals embedded in avoided cost pricing (eg, RPS).

**Commission Q:** *“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?”*

The rules established by FERC for PURPA for minimum distance between QFs are well established and appropriate, requiring no additional modification. Per above comments, larger project size brings quantifiable ratepayer benefits and market competitiveness.

Additionally, there should be explicit allowance for the project development of multiple facilities by a single entity, and shared use of common facilities (such as interconnection and tie-lines) to minimize land and environmental impacts and avoid unnecessary conflict with, and impediment of, development realities given the limited points of interconnection practically realizable by projects, due to the finite nature of transmission systems.

**Commission Q: *“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?”***

Longer standard offer contracts provide several benefits to the ratepayers, particularly in terms of facilitating the viability of the lowest possible QF projects, and thus the avoidance benefits which come with such QFs being developed. Longer terms enable projects to attract the lowest interest rates possible, which for capital intensive power assets can be a significant portion of the overall costs, as well as extend the period of capacity avoidance by the QF. At a minimum, QF contract term lengths made available should comply with the FERC guidance that such terms be long enough to facilitate facility financing. Further, it should be noted that the assets which the utilities avoided cost pricing methodologies are based on typically include

a mix of operation generation assets which are either fully depreciated or which are depreciated over terms of terms of 30 years or more. Forcing the QF to finance their projects over shorter terms (due to shorter contract lengths) necessarily and unequitably imposes higher costs on the QFs, due to underlying debt payments on new generation being for shorter terms (just like home mortgage payments, eg 15-years, vs 20-years, vs 30-years), which deprives the ratepayers of potential competitive options and the potential to avoid stair-stepped costs for new rate-based assets built by utilities. We are also at a historical low point in the natural gas price cycle, which argues that the risk of moving out of market with avoided costs is biased in favor of utility customers.

**Commission Q:** *“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?”*

Yes. But this point should not be controlled by the utility, as the LEO is a primary mechanism for protecting the QF against utilities refusal to comply with their PURPA obligations through protracting negotiations indefinitely, etc, and refusing to execute contracts. There should thus be a clear rule framework around this, specifically designed to preempt utilities potential avoidance of their mandatory purchase obligations under PURPA.

**Commission Q:** *“Should the rates and the model standard offer agreements be disaggregated into separate tariffs?”*

No, applicable rates should be included in the standard agreement, as per the rates which are in effect at the time of contract execution, so that they are fixed and the contracts are financeable. Ultimately, the financeability of the contracts resultant from Commission policy should be a

key criteria for all decisions, as the ability to finance new power generation is critical to their ability to ever exist, and thus for the Commission's policies to comply with the obligations under PURPA.

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