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September 2, 2015

Via Electronic Filing

Public Utility Commission of Oregon
Filing Center
201 High St SE, Suite 100
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Salem OR 97308-1088

RE: UM 1610 Phase II – *Investigation into Qualifying Facility Contracting and Pricing*

Attention Filing Center:

Enclosed for filing in Docket UM 1610 Phase II is Portland General Electric Company's **Pre-Hearing Brief** to be filed electronically with the Filing Center.

Thank you in advance for your assistance.

Sincerely,

V. Denise Saunders
Associate General Counsel

VDS:bop

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1610
Phase II

In the Matter of: **PUBLIC UTILITY COMMISSION OF OREGON,** **Investigation into Qualifying Facility Contracting and Pricing.**	**Pre-Hearing Brief of Portland General Electric Company**

I. INTRODUCTION

The Public Utility Commission of Oregon (Commission) opened this docket in 2012 to generally investigate issues related to electric utilities' purchases from qualifying facilities (QFs). In this second phase of the proceeding, Staff and the parties representing QFs seek to revisit many decisions that the Commission has previously ruled on. In PGE's view, the changes urged by Staff and the QF parties will lengthen and further burden existing regulatory processes and increase prices that utilities pay for QF energy to above avoided cost prices, to the detriment of the utility's customers. While PGE recognizes that changes in factual circumstances can warrant a review of earlier Commission decisions or that it may be necessary at times to obtain clarification of earlier Commission decisions, we do not believe that such circumstances exist for most of the issues discussed in this phase of the proceeding. Indeed, the explosion of QF development in Oregon being addressed in dockets UM 1725 and UM 1734 suggest that the Commission should proceed very carefully and ensure that any changes to its existing policies do not adversely impact utility ratepayers who ultimately pay the costs of QF development. *See* Order No. 14-058, Docket UM 1610 at 3. In its last order in this docket, the Commission declined to make any changes to its existing QF policies without compelling evidence of a need for the proposed revision. *Id.* at 1. We encourage it to do the same here.

II. ISSUES

1. Who owns the Green Tags during the last five years of a 20-year fixed price PPA during which prices paid to the QF are at market?

The Commission's policy on this issue was clearly articulated in Order No. 11-505:

> The renewable resource QF will keep all associated Renewable Energy Certificates (RECs)[1] during periods of renewable resource sufficiency, but will transfer those RECs to the purchasing utility during periods of renewable resource deficiency.

Order No. 11-505, Docket 1396 at 1. In that order, the Commission adopted a separate avoided cost stream for renewable resources because of the obligation of electric utilities to meet a renewable portfolio standard through the acquisition of renewable energy credits. *Id.* at 4. In other words, the purpose of the renewable fixed price PPA is for the utility to acquire the renewable attributes associated with the QF during a period of renewable resource deficiency, consistent with its need to acquire a resource to satisfy RPS. The Commission has appropriately tied the ownership of Green Tags to whether a utility is resource deficient or sufficient and not to the price paid for the energy. There is no reason to revisit the Commission's earlier decision. The fact that a utility may be paying market prices during part of the resource deficiency period does not change the utility's obligation to meet the renewable portfolio standard, and therefore its need for Green Tags. Nor do the five years of market prices at the end of the contract term change the character of the renewable fixed price PPA from a renewable avoided cost contract to a market-based contract. The Commission ordered the last five years to be priced at market in

[1] The terms "Renewable Energy Certificate", "Green Tags" and "RPS Attributes" are used interchangeably in this brief. Green tags are tradable, non-tangible energy commodities that represent proof that electricity was generated from a renewable energy resource. PGE's Schedule 201 and associated Power Purchase Agreements ("PPA") use the term "RPS Attributes."

order to mitigate the divergence between forecasted and actual avoided costs at the end of the 20-year contract term. Order No. 05-584 at 20. The contract as a whole provides the QF with all of the pricing advantages inherent in an avoided cost PPA. If a QF wants to ensure that it retains the value of Green Tags after year 15, the QF, at its discretion, can always sign a 15-year fixed price PPA.

2. **Should avoided transmission costs for non-renewable and renewable proxy resources be included in the calculation of avoided cost prices?**

Avoided transmission costs should be included in the calculation of avoided cost prices only if transmission costs are truly avoided. PGE includes avoided transmission costs in its avoided cost calculations for off-system resources. (*See* PGE/500, Macfarlane-Morton/6). PGE does not include avoided transmission costs in its avoided cost calculations for on-system resources as no transmission costs are avoided. *Id.*

3. **Should the Commission revise the methodology approved in Order No. 14-058 for determining the capacity contribution adder for solar QFs selecting standard renewable avoided cost prices? If so, how?**

Commission Staff and others seek to revisit the methodology approved by the Commission in Order No. 14-058 for determining the capacity contribution adder for solar QFs selecting standard renewable avoided cost prices. That methodology is consistent with the Commission's simplified methodology for calculating avoided cost prices using the respective on- and off-peak period and payment based on volumetric output or megawatt hours (MWh). Nevertheless, Staff believes that the Commission did not intend to do what its order stated, i.e. apply the capacity percentage contribution of the QF resource type directly to the on-peak \$/MWh. (*See* Staff/500, Andrus/14).

Staff's position is that the solar capacity adder approved by the Commission in Order No. 14-058 should be modified so a solar QF would receive a fixed payment for avoided capacity costs. *Id.* at 18. Staff claims that spreading the fixed capacity costs over the proxy resource's on-peak generation results in an inadvertent "double discount" to the capacity costs and lower payments to a solar QF. *Id.* at 16. Staff argues that if the capacity costs are spread over the on-peak generation of the avoided thermal resource, a solar QF will be undercompensated because it is expected to be available for fewer hours than the avoided resource. *Id.* In essence, Staff, suggests that the reduced value of the resource should not be reflected in reduced compensation to the QF. In fact, this is not an inadvertent consequence of the existing methodology, but rather is a representation of the costs actually avoided by the Company.

For example, Staff's proposal uses the capacity factor of a solar resource included in the IRP. The capacity costs are spread over a small number of on-peak hours. As the output from the QF varies, the amount paid to the QF varies. Under Staff's proposal, if the QF has a capacity factor greater than that of the IRP solar resource, the utility will pay more than avoided cost for that capacity. The methodology adopted by the Commission in Order No. 14-058 ensures that no such overpayments are made. As such, there is no reason for the Commission to revisit its earlier decision.

4. **Should the capacity contribution calculation for standard non-renewable avoided cost prices be modified to mirror any change to the solar capacity contribution calculation used to calculate the standard renewable avoided cost price?**

PGE believes this is another issue where no change is necessary. PGE agrees with PacifiCorp and Idaho Power that the Commission should decline to revise the current rate calculation utilized in the Oregon Proxy Method, which has been in place for many years. Proposals to pay a fixed amount to QFs for avoided capacity costs misrepresent the cost of displacing a proxy resource and will further widen the difference between standard avoided cost prices and the costs that can actually be avoided by the utility. (*See* PAC/800, Dickman/13; Idaho Power/1000, Youngblood/10-11).

While we don't agree that a change is warranted to the renewable avoided cost, if the solar capacity contribution calculation for standard renewable avoided cost prices is modified, the solar capacity calculation for the standard non-renewable avoided cost price should be modified as well. Capacity under both the standard and renewable avoided cost is based on a peaking generating resource. Since the measure of capacity is the same for both standard and renewable resources, PGE believes that adjustments for capacity should also be the same, for consistency.

5. What is the appropriate forum to resolve litigated issues and assumptions?

The Commission has repeatedly addressed this issue – including in the last order issued in this proceeding. In Order No. 14-058, the Commission stated that inputs and assumptions used in avoided cost filings should be taken from IRPs, which are subject to stakeholder review. Order No. 14-058 at 12. The Commission has also repeatedly indicated that the inputs and assumptions are subject to challenge, investigation and full review in avoided cost filings. Order No. 11-505 at 11; Order No. 06-538 at 44; Order No. 05-584 at 36-37 (*We encourage ODOE and other interested parties to seek suspension of an avoided cost filing when necessary to address concerns about natural gas forecasts or any other aspect of a utility's filing.)* QFs and other parties seek to revisit this issue but provide no compelling evidence that the current process is insufficient or that any change to the Commission's earlier rulings are necessary.

The Commission's policy that utilities use inputs from their last acknowledged IRP or IRP Update as the basis for avoided cost prices makes sense because avoided costs are based on avoided resources which are determined in the IRP. In addition, parties are afforded the opportunity to seek discovery and comment during IRP proceedings on the IRP inputs, including inputs that will be used in the avoided cost calculation. Several parties express concerns that they may not be able to raise issues related to such inputs in IRP dockets. (CREA/500, Skeahan at 14; ODOE/700, Carver at 4-5). However, no party identified any circumstance where they sought to raise an issue affecting avoided costs in an IRP proceeding and were precluded from doing so. Indeed, the history of PGE's IRP proceedings indicates that issues related to avoided cost calculations are often subject to extensive discovery and comment by the parties and are ultimately addressed by the Commission. For example, in PGE's last two IRPs gas price forecasts, wind integration costs, the production tax credit and solar integration costs were subject to numerous discovery requests and comments by the parties. (PGE/700, Macfarlane-Morton at 4). PacifiCorp, likewise, has been subject to extensive discovery in its IRP proceedings. (PAC/1500, Drennan at 3-4).

Some of the parties urge the Commission to adopt additional regulatory processes for the review of avoided cost inputs and assumptions. For example, REC proposes an expanded IRP or post-filing process to allow parties to challenge inputs and assumptions made in the IRP that affect avoided cost prices. (Coalition/400, Lowe at 13-14). ODOE proposes establishing a contested case docket in parallel to a utility's IRP docket in order to resolve issues and assumptions related to calculating the utility's avoided costs. (ODOE/700, Carver at 5). These proposals are unnecessary. As discussed above, parties currently have ample opportunity to participate in the IRP process in order to provide input and challenge assumptions. The additional processes proposed by REC and ODOE would be redundant. Moreover, a post-IRP filing process, like that proposed by REC will delay what is already a robust and lengthy public IRP process. Even more significantly, any changes to the IRP assumptions after the IRP has been fully vetted and acknowledged will add uncertainty to the IRP implementation process and to future resource planning efforts.

In addition to being able to use the IRP process to raise issues related to inputs that will be used in the avoided cost calculation, parties may also raise issues during the Commission's review of a utility's avoided cost compliance filing. In Order No. 11-505, the Commission stated that following the filing of avoided costs, "the filings and rate calculations will be subject to evidentiary hearings, wherein parties will have the opportunity to review the material, conduct discovery, and propose changes." Order No. 11-505 at 11. Parties have effectively used these proceedings to challenge the avoided cost inputs used by utilities. For example, just recently, REC, CREA and Staff objected to the cost of capital input used in PGE's avoided cost update filed on May 1, 2015. *See,* Order No. 15-206, Appendix A at 4. Based on the objections, the Commission ordered PGE to revise its update and refile. *Id.* at 1.

There is also no need to impose more regulatory requirements on the existing avoided cost processes, particularly in the form of the new minimum filing requirements "MFRs" proposed by Staff. PGE already provides work papers that clearly identify the source of inputs used to calculate the avoided cost prices. (PGE/700, Macfarlane – Morton at 4). Staff states that this is not a sufficient substitute for Staff's proposed MFRs but doesn't explain why. (Staff/600, Andrus at 16). The Commission should always act carefully when imposing new regulatory requirements, as such requirements have the potential to promulgate yet additional process and controversy – for example if one party disagrees about the meaning of the new requirements or whether they have been correctly followed. The current process allows Staff and other parties the flexibility to seek information from the utilities concerning the inputs to their avoided cost filings, to the extent it is relevant and necessary.[2] The imposition of formal requirements is not needed.

In short, parties currently have two forums where they can challenge the inputs and assumptions used in avoided cost filings. They also have the ability to request clarification or additional information concerning inputs used in the utilities' avoided cost filings. There is simply no need for additional regulatory process.

6. Do the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?

The Commission's policy concerning compensation for capacity during Resource Sufficiency Periods was established ten years ago in Order No. 05-584 in which the Commission adopted a methodology that values avoided costs when a utility is in a resource sufficient position at monthly on- and off-peak forward market prices as of the utility's avoided cost filing. Order No. 05-584 at 28. PGE uses the methodology adopted by the Commission in Order No. 05-584. No party has provided any evidence that the market prices used by PGE during the Resource Sufficiency period do not sufficiently compensate for capacity.

Some parties speculate that a utility's sufficiency period may be lengthened due to a utility acquiring thermal or other capacity resources during resource sufficiency periods (Coalition/400, Lowe/18) or because of uncertainties surrounding the implementation of EPA's proposed Section 111(d) rules. (Joint QF Parties/100, Higgins/5, 10-18). However, they have provided no evidence that the speculative behavior would result in inadequate compensation for

[2] As PacifiCorp points out in response to REC's proposal that the filing requirements include a comparison of the proposed gas forecast to the recent EIA and NPCC forecast, the Commission should not require MFRs that engage in new analysis. (PAC/1200, Drennan at 13)

QF capacity. The Commission should not change its well-established methodology based on unsubstantiated speculation and concerns.

7. What is the most appropriate methodology for calculating non-standard avoided cost prices? Should the methodology be the same for all three electric utilities operating in Oregon?

In Order No. 07-360, the Commission directed utilities to calculate non-standard avoided cost prices taking into account the seven factors enumerated by FERC in 18 CFR 292.304(e)(2). Order No. 07-360, Docket UM 1129 at 15. These seven factors are:

> (i) The ability of the utility to dispatch the qualifying facility;
> (ii) The expected or demonstrated reliability of the qualifying facility;
> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
> (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
> (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
> (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.

PGE supports the continued use of this methodology but believes that utilities should have flexibility in the implementation of adjustments using the seven factors identified by FERC. This flexibility should encompass the use of the production cost models used to set net variable power costs, as such models have been vetted by stakeholders, Commission Staff and the utilities in the IRP process and can be used to assess the interpendencies across the seven factors.

8. When is there a legally enforceable obligation ("LEO")?

Commission Order No. 14-058 specifically directs the parties to address the definition of a LEO in this phase of the proceeding. Order No. 14-058 at 2, 28. All of the parties have indicated a need for clarification as to when a LEO arises.

PGE recommends that the Commission set criteria for establishing a LEO using the final executable draft contract as the basis for potential commitment by the QF. The terms of a QF agreement prior to the utility providing a final draft are not sufficiently known and clear for the QF to make a legally enforceable commitment. This is especially true for negotiated contracts. Under Appendix A of Guideline 4 of the Commission's Guidelines for Negotiation of Power Purchase Agreements for QFs 10 MW or Larger, adopted in Order No. 07-360, the specified energy and term as well as security, default, damage and termination provisions have to be negotiated. Under PGE's Schedule 202 governing negotiated QF agreements, information necessary to establish these terms and conditions may be exchanged until a final draft is issued by the utility in Step 7. At that point, the terms and conditions are known such that a QF may commit.

The Commission should refrain from adopting any criteria that would require a utility to accept and pay for energy from a QF that the utility has little or no information about. As PacifiCorp points out, such a result would present commercial, safety and resource planning issues for the utility. (PAC/1000, Griswold at 20). It would also be inconsistent with the due diligence that utilities exercise when entering into non-QF contracts.

Concerns about the utility's ability to delay or avoid execution of the agreement are already mitigated by the specific timelines contained in utility avoided cost schedules (See, e.g., PGE Schedule 202), the expedited dispute resolution process established by the Commission in Order No. 07-360, and specific prohibitions on delaying negotiations in the utilities' avoided cost schedules. [3]

[3] PGE's Schedule 202 states that PGE "not unreasonably delay negotiations and respond in good faith to any additions, deletions or modifications to the draft Negotiated Agreement that are proposed by the Seller."

If there are disputes during the contract negotiation process that cannot be resolved before the avoided cost update goes into effect then the Commission should determine the appropriate avoided cost price that should apply when it resolves the contractual dispute under its dispute resolution process. This removes any incentive for parties to submit disputes to the Commission for the purpose of "locking in" lower or higher avoided cost prices prior to a price revision.

9. How should third-party transmission costs to move QF output in a load pocket to load be calculated and accounted for in the standard contract?

Commission Order No. 14-058 directs the parties to address the calculation of third-party transmission costs to move QF output in a load pocket to load. Order No. 14-058 at 2. PGE believes that the price the utility pays to the QF should be adjusted to compensate the utility for any third-party transmission costs that it incurs to deliver the QF's energy to the load pocket. Load pockets can arise when part of a utility's system is separate from other parts of that same utility's system. (PGE/500, Macfarlane - Morton at 13). In some instances, the additional generation provided by a QF creates a situation in which the new generation exceeds local load. *Id.* In such cases, the utility will incur incremental transmission costs to wheel the QF generation across third party transmission from the load pocket to another part of the utility's system. *Id.* Whether the QF chooses a standard or negotiated PPA, the QF price should be adjusted to compensate the utility for any third-party transmission costs that it incurs to deliver the QF's energy to load. This treatment is consistent with the requirement for an off-system QF to pay the transmission costs for delivering QF generation to the utility's system, and our earlier position that transmission costs are only added to the avoided cost calculation when the QF allows the utility to in fact avoid such transmission costs. If the price the QF is paid is not adjusted for third-party transmission to move QF output in a load pocket to load, then the utility pays a price higher than its avoided cost. *Id.* PGE has not proposed a specific method for assessing the transmission costs associated with moving QF energy from load pockets to load.

III. SUMMARY

In summary, PGE's positions on the issues presented in this docket are as follows:

Issues 1, 3, 4, 5, and 6: There is no compelling evidence indicating that the Commission should change its existing QF policies to address these issues.

Issue 2: No party has presented any evidence that PGE needs to change its calculation of avoided transmission costs.

Issue 7: The Commission should retain its existing methodology for calculating non-standard avoided cost prices but should provide flexibility in its implementation and allow utilities to use computer models to calculate such prices.

Issue 8: The Commission should set criteria for establishing a LEO using the final executable draft contract as the basis for potential commitment by the QF.

Issue 9: The price the utility pays to the QF should be adjusted to compensate the utility for any third-party transmission costs that it incurs to deliver the QF's energy to the load pocket. PGE takes no position on the specific method for assessing the transmission costs associated with moving QF energy from load pockets to load.

IV. CONCLUSION

No party has offered compelling evidence that warrant a change to the Commission's existing QF policies for questions discussed under Issues 1 through 6. Accordingly, PGE respectfully requests that the Commission refrain from making any such changes. PGE requests

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that the Commission clarify its existing policies as discussed above for Issues 7 through 9.

DATED this 2nd day of September, 2015.

Respectfully submitted,

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