Portland General Electric Company
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May 22, 2015

Via Electronic Mail
puc.filingcenter@state.or.us

Oregon Public Utility Commission
Attention: Filing Center
PO Box 1088
Salem OR 97308-1088

Re: UM 1610 -- INVESTIGATION INTO QUALIFYING FACILITY CONTRACTING AND PRICING

Attention Filing Center:

Enclosed for filing in Docket Number UM 1610 are Portland General Electric's Company's Direct Testimony of Robert Macfarlane and John Morton.

Please contact the undersigned if you have any questions.

Sincerely,

Karla Wenzel
Manager, Pricing & Tariffs

KW:sp

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I. I. Introduction and Summary

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Robert Macfarlane. I am a senior analyst in Pricing and Tariffs. My qualifications appear in our phase 1 direct testimony, Exhibit 100.

My name is John Morton. I am a specialist in Structuring and Origination. My qualifications also appear in our phase 1 direct testimony, Exhibit 100.

Q. What is the purpose of your testimony?

A. Our testimony responds to the nine issues in the UM 1610 Phase II issues list established by the Administrative Law Judge on March 26, 2015.

Q. What are the nine issues to be addressed in Phase II?

A. The issues are:

1. Who owns the Green Tags during the last five years of a 20-year fixed price power purchase agreement ("PPA") during which prices paid to the QF are at market?
2. Should avoided transmission costs for non-renewable and renewable proxy resources be included in the calculation of avoided cost prices?
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?
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?

5. What is the appropriate forum to resolve litigated issues and assumptions?
6. Do the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?
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?
8. When is there a legally enforceable obligation?
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?

Q. Please summarize your key recommendations and proposals.

A. Our recommendations are as follows:

1. The utility should own the Green Tags for any renewable power purchase during a period of resource deficiency.
2. Avoided transmission costs should be included in the calculation of avoided cost prices only if transmission costs are truly avoided.
3. The Commission was correct in approving the methodology for determining the capacity contribution adder for solar QFs in Order No. 14-058. No revision is necessary.
4. Adjustments for capacity should be the same for both standard and renewable resources for consistency since the measure of capacity for both resources is also the same.
5. The Commission's rules and processes already allow parties ample opportunity to resolve issues related to the assumptions used in avoided cost filings.

6. No capacity payment is warranted during the sufficiency period.
7. For non-standard avoided cost prices, utilities should use the methodology established in Order No. 07-360, adjusting standard avoided costs for QF specific characteristics consistent with the seven factors outlined in 18 CFR 292.304(e)(2)[1]. The three utilities should have flexibility in the implementation of adjustments using the seven FERC adjustment factors.
8. The Commission should set criteria for establishing a legally enforceable obligation using the final executable draft contract as the basis for potential commitment by the QF.
9. 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 the load pocket.

[1] https://www.law.cornell.edu/cfr/text/18/292.304

II. Discussion by Issue

Issue 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?

Q. What is PGE's position on Issue 1?

A. If the utility is resource deficient in the last five years of a 20-year fixed price PPA, the utility should receive Green Tags for renewable power purchases during this period. We note that QFs have the option to sign a 15-year fixed price PPA if they want to retain Green Tags after year 15.

Q. What are Green Tags? How are they defined?

A. Green tags are tradable, non-tangible energy commodities that represent proof that **electricity** was generated from a **renewable energy** resource. In PGE's Schedule 201 and associated PPAs, the terms "Environmental Attributes" and "Renewable Portfolio Standard ("RPS") Attributes" are used.

The term "Environmental Attributes" is defined as:

> any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

The term "RPS Attributes" is defined as:

> all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

When we refer to "Green Tags" in our testimony, we mean RPS Attributes as defined in our Schedule 201 and associated PPAs.

Q. As Green Tags are currently defined, can the purchase of energy without Green.

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When we refer to "Green Tags" in our testimony, we mean RPS Attributes as defined in our Schedule 201 and associated PPAs.

Q. As Green Tags are currently defined, can the purchase of energy without Green Tags be considered renewable for purpose of meeting Oregon's RPS?

A. No. Energy purchased without Green Tags is not renewable energy and thus cannot be used to meet an Oregon utility's RPS compliance requirements.

Q. During a period of resource deficiency, would it make sense for an Oregon utility to pay for power without Green Tags under a standard renewable PPA?

A. No. The purpose of entering into a standard renewable PPA as opposed to a standard PPA is for the utility to acquire Green Tags during a period of resource deficiency. If the utility is entering into a standard renewable PPA and guaranteeing that it will purchase the QF power, the utility should own the Green Tags regardless of the price of purchase during a period of resource deficiency.

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

Q. What is PGE's position on Issue 2?

A. 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 proxy resources that incur transmission costs. PGE would not include avoided transmission costs in its avoided cost calculations when a proxy resource incurs no transmission costs.

Issue 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?

Q. What is PGE's position on Issue 3?

A. The Commission was correct in approving the methodology for determining the capacity contribution adder for solar QFs in Order No. 14-058. Please see PGE Exhibit 400 for our testimony on this issue.

Issue 4: Should the capacity contribution calculation for the 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?

Q. What is PGE's position on Issue 4?

A. Capacity under both the standard and renewable avoided cost prices 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.

Q. If the solar capacity contribution calculation for standard renewable avoided cost prices is modified, should the solar capacity calculation for the standard non-renewable avoided cost price be modified as well?

A. Yes, while we don't agree that a change is warranted under the standard renewable avoided cost prices, we propose to keep the capacity contribution calculation consistent.

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

Q. What is PGE's position on Issue 5?

A. The Commission's rules and processes already allow parties ample opportunity to resolve issues related to the assumptions used in avoided cost filings.

Q. Do the "litigated issues and assumptions" in Issue 5 refer to solely to issues and assumptions with an avoided cost filing?

A. Yes. As stipulated by parties and consistent with ALJ's Brief in Support of the Stipulation on pages 8 and 9, we interpret the "litigated issues and assumptions" in Issue 5 as those litigated issues and assumptions with PGE's avoided cost filings.

Q. Do parties currently have a forum to resolve litigated issues and assumptions?

A. Yes. In Oregon Public Utility Commission (OPUC or Commission) 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.

Q. What other opportunities do the parties have to raise issues with regard to assumptions used in avoided costs calculations?

A. The Commission's policy is that utilities use inputs from their last acknowledged IRP as the basis for avoided cost prices. Parties are afforded opportunity to seek discovery and comment on the IRP inputs during the IRP proceeding.

Q. Does the current forum to resolve litigated issues and assumptions need to change?

A. No. We believe the processes currently available provide a sufficient and efficient way to resolve litigated issues and assumptions.

Q. Does PGE offer any ways to make this process easier and more successful?

A. PGE is willing to provide citations in its avoided cost filings to the IRP assumptions used in the calculation of avoided costs. Our most recent avoided cost update, filed on May 1, 2015, include those references.

Issue 6: Whether the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?

Q. What is PGE's position on Issue 6?

A. No additional payment for capacity is warranted during the sufficiency period. PGE is capacity sufficient through the sufficiency period. A capacity payment during the sufficiency period results in prices that exceed the avoided cost of the utility.

Q. Historically, how has capacity been valued in the calculation of avoided costs?

A. Prior to the issuance of OPUC Order No. 05-584, PGE and PacifiCorp calculated avoided costs based only on the variable cost of operating existing generating resources during periods of resource sufficiency.

Q. How has the valuation of capacity in the calculation of avoided costs changed since then?

A. In UM 1129 discussions, Staff and several other parties argued that QF capacity should be compensated for at all times including when a utility is resource sufficient. The Commission adopted Staff's recommendation to value QF capacity based on the market in Order No. 05-584 stating:

> …we adopt the 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. We agree with Staff that this approach embeds the value of incremental QF capacity in the total market-based avoided cost rate. We find this valuation mechanism to be appropriate given the likelihood that a utility will address probable gaps between increasing demand and actual resources, in the absence of incremental QF capacity, with purchases of energy and capacity on the market. Indeed, we find PGE's recent history of buying significant resources on the market prior to a commitment to build new utility plant to be illustrative. To the extent that a party can provide evidence regarding the market pricing of capacity, however, we remain open to reconsideration of this decision in the next phase of this proceeding.

Q. Have there been changes in the market pricing of capacity since the issuance of Order No. 05-584?

A. No, there is still no market pricing for capacity beyond the market prices already included in the avoided cost during the sufficiency period.

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

Q. What is PGE's position on Issue 7?

A. PGE supports the use of the methodology established in Order No. 07-360, adjusting avoided costs for QF specific characteristics consistent with the seven factors outlined in 18 CFR 292.304(e)(2)[2]. The three utilities should have flexibility in the implementation of adjustments using the seven FERC adjustment factors.

Q. For the record, please recount the seven factors of 18 CFR 292.304(e)(2).

A. The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

[2] https://www.law.cornell.edu/cfr/text/18/292.304

> (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.

Q. How should the seven factors of 18 CFR 292.304(e)(2) be taken into account?

A. These seven factors should be considered for all negotiated contracts whether they are additions or subtractions. Adjustments to standard rates are expressly allowed by PURPA under 18 CFR § 292.304(c)(3) which states:

> The standard rates for purchases under this paragraph:
>
> (i) Shall be consistent with paragraphs (a) and (e) of this section; and
>
> (ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

Paragraph (e) in the reference above provides the list of the seven adjustment factors and (a)(2) states:

> Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

Q. Should all Oregon utilities use the same methodology taking the seven FERC factors into account?

A. No. Each utility should take the seven FERC factors into account based on their respective system characteristics.

Issue 8: When is there a legally enforceable obligation?

Q. What is PGE's position on Issue 8?

A. PGE recommends that the Commission set criteria for establishing a legally enforceable obligation 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 such a commitment. This is especially true for negotiated contracts. Under 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.

Q. How does PGE's proposed approach comport with concerns that the utility has the opportunity to delay or avoid execution of the agreement?

A. Concerns about the utility's ability to delay or avoid execution of the agreement are mitigated by the specific timelines contained in Schedule 202, the expedited dispute resolution process established by the Commission, and the requirement set forth in our schedule 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."

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

Q. What is PGE's position on Issue 9?

A. PGE believes that 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 the load pocket.

Q. What is a load pocket?

A. Load pockets are unique circumstances where part of a utility's system is separate from other parts of that same utility's system. In some instances, the additional generation from the QF creates a situation in which the new generation exceeds local load.

Q. Do load pockets result in additional transmission costs for the utility?

A. They can. Any time the QF generation exceeds local load 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. The utility then incurs additional costs to secure transmission services from the third-party transmission provider.

Q. How does PGE propose to resolve the issue of third-party transmission costs to move QF output in a load pocket to load?

A. 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. 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.

Q. Does this conclude your testimony?

A. Yes.