Oregon

John A. Kitzhaber. MD. Governor

Public Utility Commission
550 Capitol St NE, Suite 215
Mailing Address: PO Box 2148
Salem, OR 97308-2148
Consumer Services
1-800-522-2404
Local: (503) 378-6600
Administrative Services
(503) 373-7394

March 18, 2013

Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: Docket No. UM 1610 – In the Matter of
PUBLIC UTILITY COMMISSION OF OREGON
Staff Investigation Into Qualifying Facility Contracting and Pricing.

Enclosed for electronic filing in the above-captioned docket is Staff Response Testimony.

/s/ Kay Barnes
Kay Barnes
PUC- Utility Program
(503) 378-5763
kay.barnes@state.or.us

c: UM 1610 Service List (parties)

PUBLIC UTILITY COMMISSION
OF OREGON

UM 1610

STAFF RESPONSE TESTIMONY OF

ADAM BLESS

In the Matter of
PUBLIC UTILITY COMMISSION OF OREGON
Staff Investigation Into Qualifying Facility
Contracting and Pricing.

March 18, 2013

CASE: UM1610
WITNESS: ADAM BLESS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Response Testimony

March 18, 2013

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Adam Bless. I am a Senior Utility Analyst for the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to provide staff's recommendations regarding issues 1, 2, 3, 4, 5, 6.b, 6.e and 6.i in Appendix A of the December 21, 2012 Administrative Law Judge's Procedural Ruling (Issues List). Those issues cover the calculation methodology for the avoided cost prices paid to Qualifying Facilities (QFs) under PURPA, the avoided cost price calculation for the renewable avoided cost stream created in December 2011 in Order 11-505, price adjustments for specific QF generation types, the schedule for avoided cost updates, eligibility for the standard contract, the contract term, the mechanical availability guarantee, and the establishment of a legally enforceable obligation as that term is used under PURPA.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. Exhibit Staff/102 illustrates staff's recommended method for calculating the standard avoided cost price. Exhibit Staff/103 illustrates staff's recommendation for the renewable avoided cost price calculation.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Staff recommends a modification to the calculation of both standard and renewable avoided cost prices to address an existing mismatch between the value of purchases from QFs and avoided cost payments made to QFs. Specifically, staff recommends modifying the current Standard Avoided Cost Price Method and the Renewable Avoided Cost Price Method to adjust avoided cost prices to account for the capacity contribution of different QF resource types during resource deficiency periods. Staff also recommends that the Commission expressly include avoided integration costs and avoided transmission costs in the calculation of avoided cost prices and clarify that actual integration costs and transmission costs are the responsibility of the QF, and not included in the calculation of avoided cost prices.

Because Staff's proposed modifications to the avoided cost price methodologies and clarification as to what costs are included in the avoided cost calculation are intended to address concerns regarding potential for overpayments to QFs, staff recommends that the Commission not address these concerns by lowering the eligibility cap for standard and renewable avoided cost prices. However, if the Commission does not adopt staff's proposed modifications, staff recommends that the Commission reduce the eligibility cap to 3 MW for both renewable and non-renewable QFs to minimize the impact from any mismatch between the value of purchases from QFs, the utilities' costs to integrate energy from intermittent resources, and payments to QFs based on the utilities' avoided costs.

Staff also recommends that the Commission modify the schedule for updating avoided cost prices to include annual revisions based on updated forward market prices and updated natural gas prices. These limited annual updates would be in addition to the biennial revisions after IRP acknowledgment. Finally, staff recommends that the Commission: (1) use Oregon's definition of "RECs" to define the non-energy attributes of QF energy for purposes of PURPA transactions; (2) eliminate unused variable market-based pricing options; (3) authorize contractual limits on scheduled maintenance and penalties when the limits are exceeded; and (4) clarify what action a QF can take to establish legally enforceable obligation. Otherwise, Staff recommends no changes to previously-established Commission policies or decisions that are specifically at issue in this first phase of the proceeding.

Q. HOW IS STAFF'S TESTIMONY ORGANIZED?

A. Staff's testimony is organized consistently with the Issues List. The issues are addressed in sections as follows:

SECTION I: AVOIDED COST PRICE CALCULATION METHODOLOGY

Issue 1.A: What is the most appropriate methodology for calculating avoided cost prices?

Issue 1.A.i: Should the Commission retain the current method based on the cost of the next avoidable resource identified in the company's current IRP, allow an "IRP" method based on computerized grid modeling, or allow some other method?

Q. WHAT METHODOLOGY DOES STAFF RECOMMEND THE COMMISSION USE TO CALCAULATE AVOIDED COST PRICES?

A. Staff recommends that the Commission continue to use the Standard Method[1] to calculate "standard" avoided cost prices, but with price adjustments to account for the different capacity contributions to peak load of different types of QFs. Staff also recommends that the Commission continue to use the method set forth in Commission Order 11-505 (hereinafter referred to as the "Renewable Method") to calculate renewable avoided costs but also modified to adjust prices to account for the different capacity contributions to peak load of different QF types.

Q. PLEASE DESCRIBE THE CURRENT STANDARD METHOD AND RENEWABLE METHOD.

A. Under both the Standard and Renewable Methods, avoided cost prices are based on monthly on-peak and off-peak forward price curves when the utility is resource sufficient (or, in the case of the Renewable Method, when the utility is

[1] The Standard Method is the one set forth in Order 05-584 and currently used by PGE and PacifiCorp. It is also referred to as the "Oregon Method."

renewable resource sufficient). During the resource deficient periods, the Standard Method is comprised of off-peak and on-peak prices, based on the fixed and variable costs of an avoidable Combined Cycle Combustion Turbine (CCCT). The off-peak price is comprised of energy costs, which are the fuel costs plus a portion of the capital costs of the CCCT that are allocated to energy. The on-peak price includes all of the above energy costs, plus a capacity cost equal to the portion of CCCT capital costs that are allocated to capacity.

The Renewable Method is similar to the Standard Method, except that the avoided resource is the next renewable generation resource identified for acquisition in the utility's Integrated Resource Plan (IRP) for Renewable Portfolio Standard (RPS) compliance. Currently, the next avoidable renewable resource in PGE's and PacifiCorp's IRPs is a wind resource. The avoided wind resource has no fuel cost, but its total fixed costs are allocated to on-peak and off-peak prices. The on-peak price includes an implicit, although small, capacity contribution.

Q. DOES STAFF RECOMMEND INCLUDING AVOIDED TRANSMISSION COSTS IN THE CALCULATION OF AVOIDED COST PRICES IN BOTH THE STANDARD AND RENEWABLE METHODS?

A. Yes. If the utility's avoided resource is an off-system resource that requires transmission to deliver energy and capacity to the utility's system, then the avoided transmission costs should be included in the standard and renewable avoided cost prices.

Q. DOES STAFF RECOMMEND INCLUDING AVOIDED INTEGRATION COSTS IN THE CALCULATION OF AVOIDED COST PRICES UNDER THE RENEWABLE METHOD?

A. Yes. If the utility's avoided renewable resource is a variable output resource that requires integration services, the avoided integration costs should be included in the renewable avoided cost prices.

Q. PLEASE SUMMARIZE THE COMPONENTS OF THE OVERALL AVOIDED COST PRICE BASED ON THE CHARACTERISTICS OF THE UTILITY'S AVOIDED RESOURCE.

A. Avoided energy costs and avoided capacity costs are always components of the overall avoided cost prices under both the Standard and Renewable Methods. Avoided transmission costs are a component of the overall avoided cost prices whenever the utility avoided resource is off-system. Avoided integration costs are a component of the overall renewable avoided cost price whenever the utility's avoided resource is a variable output resource. The components of the avoided cost are summarized below on Table 1:

TABLE 1: Summary of Costs Included in the Avoided Cost Price

Avoided Resource	Energy	Capacity	Avoided Transmission	Avoided Integration
On-System CCCT	Yes	Yes	No	No
Off-System CCCT	Yes	Yes	Yes	No
On-System Wind	Yes	Yes	No	Yes
Off-System Wind	Yes	Yes	Yes	Yes

Q. HOW DOES STAFF RECOMMEND ADJUSTING THE AVOIDED CAPACITY COSTS BASED ON THE CHARACTERISTICS OF THE QF RESOURCE?

A. I describe Staff's proposed adjustments to the avoided capacity payments in Section 4, which covers adjustments for characteristics of the QF.

Q. DOES STAFF ADDRESS THE TRANSMISSION COSTS AND INTEGRATION COSTS ASSOCIATED WITH THE QF RESOURCE?

A. Yes. I describe Staff's proposed assignment of these costs in Section 4.

Q. DOES STAFF PROPOSE OTHER CHANGES TO EITHER THE CURRENT STANDARD METHOD OR RENEWABLE METHOD?

A. No. Under Staff's proposal, QFs would continue to receive a forward-looking market price during the utility's resource sufficient periods under the Standard option or the renewable-resource sufficient period under the Renewable option. During the resource deficient periods, standard avoided cost prices would be based on costs of a CCCT (for standard avoided cost rates) and the next avoidable renewable resource (for renewable avoided cost rates). The sufficiency period would be determined by the utility's acknowledged IRP, as is currently done.

Q. WHAT OTHER METHODS FOR CALCULATING STANDARD AVOIDED COST PRICES DID STAFF CONSIDER?

A. Staff considered keeping the current Standard Method, with no changes. Staff also considered the Present Value Differential Revenue Requirement (PVDRR) method described by PacifiCorp in its Opening Testimony, and the IRP Method described by Idaho Power.

Q. PLEASE BRIEFLY DESCRIBE THE PACIFICORP AND IDAHO POWER PROPOSALS.

A. Both methods rely on proprietary software to model the grid on an hour by hour basis and calculate a total revenue requirement for the utility system. PacifiCorp runs the model once without the QF power to produce a base case. They run the model a second time with the QF power artificially input at zero cost. The difference in revenue requirement between the two model runs is the avoided cost price. (PAC/100, Dickman/11-12). Idaho Power used essentially the same method in the past. It now proposes a modified method that models, on an hourly basis, the generating resource whose output is displaced by the QF power. The incremental cost of that displaced generation is considered the avoided cost. (Idaho Power/200, Stokes/34-36.)

Q. WHAT ADVANTAGES OF THESE MODEL-BASED APPROACHES DID STAFF CONSIDER WHEN MAKING ITS RECOMMENDATION?

A. Staff considered the fact that these model-based methods account for a greater array of costs associated with the purchase of QF power; specifically those costs avoided by the utility and actual costs incurred by the utility because of specific operating characteristics of the QF. The models take into account the hourly variations in the QFs expected generation and in the utility's load. The models are well established and in fact are the same models that are used to prepare the Integrated Resource Plan. They inherently factor in the different operating characteristics of wind, solar and other QF types. Staff also considered the fact that model-based approaches have already been used for large (> 10 MW) QFs, and are already used in many other states.

Q. ARE THERE POTENTIAL DRAWBACKS TO THE MODEL-BASED APPROACHES?

A. Yes. Staff's chief concern is that the model-based approaches are not transparent to the QF developers and their lenders. Understanding the results from the modeling methodology requires the reviewer to understand how the model works, its sensitivity to different inputs, and how the model approximates the complexities of the Western grid. Further, while the models produce more detailed cost calculations, the results remain only as accurate as the forecasts and other inputs. Simply adopting model-based approaches will not guarantee more accurate avoided-cost prices.

Q. WHAT ADVANTAGES AND CONCERNS DID STAFF CONSIDER REGARDING THE CURRENT STANDARD METHOD?

A. The current Standard Method has been used by PGE and PacifiCorp since the issuance of Order 06-538. It is familiar to the utilities and to QF developers. The calculation is a straightforward spreadsheet with inputs and assumptions that are easy to identify and review. By using forecasts and cost assumptions that are consistent with the IRP, we assure that the inputs to the Oregon Method are derived from an open and transparent process and are the same inputs used to inform resource acquisition decisions. Staff's proposed modifications to the Standard Method are intended to address concerns regarding accuracy while retaining the overall structure.

Q. DOES STAFF RECOMMEND CHANGING THE POLICY OF DIVIDING THE AVOIDED COST PRICE SCHEDULES INTO RESOURCE SUFFICIENCY AND DEFICIENCY PERIODS?

A. No. Staff supports the continued use of separate resource sufficiency and resource deficiency periods, with the utilities' IRPs used to identify the year of transition. We base our recommendation to keep the differentiation, in part, on the failures of Idaho Power's "SAR" method described in the testimony of Idaho Power.

<u>Issue 1.A.ii</u>: Should the methodolog[ies] be the same for all three electric utilities operating in Oregon?

Q. SHOULD ALL ELECTRIC UTILITIES OPERATING IN OREGON USE STAFF'S PROPOSED MODIFIED OREGON METHOD?

A. Yes. In Order 05-584 the Commission allowed Idaho Power to use the Idaho method in Oregon for reasons of administrative efficiency. In January 2012, Idaho Power submitted a petition for investigation (UM 1593), stating that its current avoided cost prices (based on the Idaho method) resulted in unduly high costs to ratepayers. The Commission ordered a temporary stay on new Idaho Power QF contracts in Oregon until Idaho Power could submit newer and more up to date prices. In other words, the administrative efficiencies of using the same method in both states were outweighed by the high costs documented in Idaho Power's petition in UM 1593. Moreover, the Idaho Commission has approved a 100 kW standard contract eligibility cap for wind and solar.[2] As discussed below, staff does not support a 100 kW cap. Therefore, the administrative efficiency considerations are less compelling now than they were in Docket No. UM 1129.

Q. WILL USING TWO METHODS IN TWO STATES UNDULY BURDEN IDAHO POWER?

A. No. Idaho Power is familiar with the Standard Method, having used it to calculate avoided cost prices that the Commission approved in May 2012. Staff's proposed adjustments to the avoided capacity payments based on the characteristics of the QF resource (described in Section 4) result in essentially the same modification Idaho Power proposes to use in Idaho for QFs smaller than 100 kW. The calculation itself is a familiar spreadsheet, and the inputs and assumptions would be taken from Idaho Power's IRP.

Q. SHOULD ALL THREE UTILITIES USE THE MODIFIED RENEWABLE METHOD?

A. PacifiCorp and PGE should use the modified Renewable Method to calculate renewable avoided cost prices. The Commission has not ordered Idaho Power to offer renewable avoided cost prices in Oregon. Accordingly, the Renewable Method is not applicable to Idaho Power.

<u>Issue 1.B.</u> *Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?*

Q. DOES STAFF RECOMMEND THAT QFs HAVE THE OPTION OF SELECTING FULLY OR PARTIALLY LEVELIZED PRICES?

---

[2] Idaho Power/200 at Stokes/4

A. No. The Commission considered proposals for levelized prices in Docket No. UM 1129 and decided against them. Staff reviewed Order 05-584 and believes that the arguments for and against levelized prices described in that order have not changed.

Q. PLEASE SUMMARIZE THOSE ARGUMENTS AS CHARACTERIZED IN ORDER NO. 05-584.

A. Utilities stated that levelizing payments will front-end load the avoided cost payments, putting ratepayers at risk if the QF reliability or output declines in the later years of the contract. QFs supported levelizing based on the improved cash flow that it provides. The Oregon Department of Energy's (ODOE's) Small Scale Energy Loan Program (SELP) also supported levelized payments in order to improve the likelihood of the QF repaying the loan. Staff, in 2005, contended that levelized payments serve as compensation for a QF's assistance in meeting future demand growth, and encourage QF development. (Order No. 05-584 at 23).

Q. HAVE THE LIKELY ARGUMENTS CHANGED IN LIGHT OF INCREASED QF CONTRACTING EXPERIENCE SINCE ORDER NO. 05-584?

A. The arguments above remain fundamentally unchanged. The utilities' opening testimony of February 4, 2013 repeat the same concerns about front-end loading the avoided cost payments, with ratepayers bearing the risk if QF output declines in the late years of the contract. (Idaho Power/200, Stokes/74-75; PGE/100, Macfarlane-Morton/13-14.) In its role as lender, ODOE's SELP remains justifiably concerned with assuring that its loans are repaid. The

Renewable Energy Coalition, in its petition for UM 1457, also echoed arguments from Docket No. UM 1129, asking the Commission to use levelized payments as a means to encourage QF development. (Docket No. UM 1457; REC Petition to Initiate Investigation into Utility Practices that Discourage Development of Renewable Resources 8-9.) Staff sees no real change in the arguments regarding levelization since 2005 and therefore recommends the Commission not levelize avoided cost prices.

<u>Issue 1.C</u>. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different than the market price?

Q. SHOULD QFs BE ALLOWED TO AVOID SUFFICIENCY PERIOD MARKET PRICES UPON RENEWAL OF A STANDARD CONTRACT?

A. No. Staff recommends retaining the current policy, in which the price schedule of a renewing contract begins with a new sufficiency period. QFs should not be allowed to get deficiency period prices during a utility's sufficiency period.

Q. WHAT ARGUMENTS DID STAFF CONSIDER IN MAKING THIS RECOMMENDATION?

A. Staff reviewed the Commission's reasoning in Order No. 05-584. This question was raised by QF stakeholders who were concerned that QFs reaching the end of their initial contract will become uneconomic to operate under a renewed contract that includes a new sufficiency period. Staff's understanding is that levelized payments in a renewing contract, or, in the alternative, beginning the renewed contract with the resource deficient price, are ways to extend the life of an existing QF.

Q. WHY DOES STAFF RECOMMEND NO CHANGE TO CURRENT PRACTICE?

A. This proposal is similar to the Industrial Customers of Northwest Utilities (ICNU) 2005 position that contracts should be extended through the economic life of the facility ("evergreen"). The Commission considered that proposal in Order 05-584 but found that ". . . the contract term length minimally necessary to ensure that most QF projects can be financed should be the maximum term for standard contracts." (Order No. 05-584 at 19.) This language makes clear that the Commission was concerned about risk to ratepayers from extended contracts. Staff sees no reason why this policy goal has changed. Therefore, we recommend no change to current practice.

Issue 1.D: *Should the Commission eliminate unused pricing options?*

Q. ARE THERE UNUSED PRICING OPTIONS?

A. Yes. In response to staff data requests, all three Oregon utilities report that since 2005, no QF has used the variable market-based options.

Q. SHOULD UNUSED PRICING OPTIONS BE ELIMINATED?

A. Yes, the unused variable market-based options complicate the avoided cost price schedules and staff recommends that the Commission eliminate them. The unused options offered by PacifiCorp are the "Gas Market Indexed" and "Banded Gas Market Indexed" pricing options. (PAC/200, Stokes/6-7.) The unused options offered by PGE are the "Deadband Index Gas Price Option," the "Index Gas Price Option," and the "Mid-C Index Option." (PGE/100, Macfarlane-Morton/15.) These unused options should be eliminated and going forward, all standard contracts should value QF energy using the "fixed" option based on the gas price forecasts from the utilities' current IRPs.[3]

SECTION 2: RENEWABLE AVOIDED COST PRICE CALCULATION

Issue 2.A: *Should there be different avoided cost prices for different renewable generation sources? (For example different avoided cost prices for intermittent vs. base load renewables; different avoided cost prices for different technologies, such as solar, wind, geothermal, hydro, and biomass.)*

Q. DOES STAFF RECOMMEND DIFFERENTIATING AMONG RESOURCE TYPES FOR PURPOSES OF CALCULATING RENEWABLE AVOIDED COST PRICES?

A. As discussed briefly in Section 1 and more fully in Section 4, staff recommends that the Commission modify the Renewable Method to account for the differing peak load capacity contributions of different types of QF resources. Otherwise, staff recommends no change to the Renewable Method, under which the costs the utility is assumed to avoid during the deficiency periods are the costs of the utility's next avoidable renewable resource in its IRP.

Q. WHAT OPTIONS DID STAFF CONSIDER IN MAKING THIS RECOMMENDATION?

[3] As discussed below, staff continues to support the policy of Order 05-584 regarding the use of the fixed price only in the first 15 years. For any period after 15 years, a market-based option would be used.

A. Staff considered three options: (1) retain the policies in Order No. 11-505 under which utilities offer only one renewable price stream and QFs have the option to select that price stream or the standard avoided cost price stream; (2) adopt the methods proposed by PGE and PacifiCorp in their February 2012 compliance filings in UM 1396; or (3) adopt renewable avoided cost price schedules that include price adjustments for certain characteristics of different categories of renewable QFs.

Q. WHY DOES STAFF RECOMMEND PRICE ADJUSTMENTS FOR DIFFERENT RENEWABLE QF TYPES WHEN THE COMMISSION HAS NOT ADOPTED SUCH ADJUSTMENTS BEFORE?

A. Staff's recommendation is based largely on the conclusion that the potential mismatch between the utilities' avoided capacity payments, which is dependent on the characteristics of the utility's avoided resource, and the capacity benefits of the QF resource is too large to go unaddressed. All three utilities recommend addressing this mismatch by lowering the eligibility cap. (Idaho Power/200, Stokes/46-47, 52-56; PGE/100, Macfarlane-Morton/6-7; PAC/200, Griswold/16-20.) Staff recommends maintaining the eligibility cap at 10 MW, but adjusting the utilities' avoided cost prices to account for differences in the value of capacity produced by wind, solar and base load renewable QFs. As discussed in Section 5 of this testimony, if the Commission does not adopt Staff's recommended modifications to the Oregon Method and Renewable Method, Staff recommends that the Commission lower the eligibility cap to 3 MW to minimize the impact of the mismatch between the utilities' avoided capacity payments to the QF and the capacity benefits received from QF purchases.

Issue 2.B. *How should environmental attributes be defined for purposes of PURPA transactions?*

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE DEFINITION OF ENVIRONMENTAL ATTRIBUTES?

A. Environmental attributes should be those attributes that are quantified and certified under the Renewable Energy Certificate (REC) program overseen in Oregon by the Oregon Department of Energy (ODOE).

Q. WHY DOES STAFF RECOMMEND THAT ENVIRONMENTAL ATTRIBUTES BE LIMITED TO RENEWABLE ENERGY CERTIFICATES FOR PURPOSES OF PURPA TRANSACTIONS?

A. We recommend this because it is consistent with the definition of avoided cost. If not for its purchase of power from renewable QFs, the utility would incur some costs related to energy and capacity, as well as costs associated with meeting Oregon's Renewable Portfolio Standard (RPS). Other costs, such as costs associated with future carbon legislation, may be incurred in the future. However, there is too much uncertainty to represent possible future legislation in avoided cost price calculations right now. For now, utilities comply with the Oregon RPS by purchasing renewable energy either directly or through RECs.

Issue 2.C. *Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?*

Q. WHAT POLICY DOES STAFF RECOMMEND REGARDING REC OWNERSHIP?

A. Staff recommends keeping the policy set forth in Order Nos. 05-584 and 11-505. If the QF chooses the Standard (nonrenewable) price, then the utility is paying for energy and capacity, nothing more. That's all it should receive. If a QF opts for the renewable price stream, then it receives the market price during the sufficiency period and keeps the RECs. During the deficiency period the utility is compensating the QF for the renewable attributes, and should therefore receive the renewable certificate.

Q. DOES STAFF RECOMMEND MODIFYING OAR 860-022-0075, WHICH SPECIFIES THAT THE NON-ENERGY ATTRIBUTES OF ENERGY REMAIN WITH THE GENERATOR UNLESS OTHERWISE SPECIFIED IN CONTRACT?

A. No. OAR 860-022-0075 provides, in pertinent part:

> (2) Unless otherwise agreed to by separate contract, the owner of the renewable energy facility retains ownership of the non-energy attributes associated with electricity the facility generates and sells to an electric company pursuant to:
>
> * * * * *
>
> (b) An Oregon contract with the electric company entered into pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978[.]

A utility is entitled to the quantifiable non-energy attributes associated with a QF's energy when the QF elects the renewable avoided cost price stream and when the QF is compensated for the RECs, which is during the deficiency periods of the contract between the QF and the utility. In order to receive payments under the renewable avoided cost price stream, the QF must agree, in the standard contract, to deliver its RECs to the utility during the deficiency periods of the contract. Accordingly, the language in the rule is consistent with the Commission's policy regarding when non-energy attributes belong to the utilities.

SECTION 3: SCHEDULE FOR AVOIDED COST UPDATES

Issue 3.A: *Should the Commission revise the current schedule of updates at least every two years and within 30 days of IRP acknowledgment?*

Q. SHOULD THE COMMISSION REVISE THE CURRENT SCHEDULE OF AN UPDATE EVERY TWO YEARS AND AN UPDATE WITHIN 30 DAYS OF EACH IRP ACKNOWLEDGEMENT ORDER?

A. Yes. The current biennial schedule is not sufficient to keep up with the pace of change in the energy markets. All three utilities recommend more frequent updates. QF developers have requested more certainty and predictability in the update schedule, most notably in the petition that initiated UM 1457. (UM 1457; 2009 REC Petition to Initiate Investigation into Utility Practices that Discourage Development of Renewable Resources 3-5.) A more frequent schedule of updates would better serve both utilities and QFs.

Q. WHAT DOES STAFF PROPOSE?

A. Staff supports an annual update to the gas price forecast and the on-peak and off-peak forward market prices used in the avoided cost calculations. Staff recommends that all three utilities be required to file updated avoided cost prices with these limited updates on March 1st each year (or the next business day if March 1st falls on a weekend). Staff continues to support a complete update to all avoided cost inputs after Commission acknowledgement of the utility's IRP. Staff continues to recommend that the utilities be required to file the complete update within 30 days of IRP acknowledgement.

Q. WHY IS THIS RECOMMENDATION AN IMPROVEMENT OVER THE CURRENT SCHEDULE?

A. Staff expects the annual update to largely eliminate the incentive for utilities to request mid-cycle updates when gas and market prices are going down. An annual update also assures QFs that avoided cost prices will rise more in synch with rising gas and market prices. Staff supports retaining the complete update following IRP acknowledgement. A new IRP affects so many variables that the avoided cost price schedule should always reflect the latest IRP to the extent practicable.

Q. DOES STAFF RECOMMEND REVISIONS TO THE AVOIDED COST PRICE UPDATE REVIEW PROCESS?

A. No.

<u>*Issue 3.B*</u>*: Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate?*

Q. DOES STAFF SUGGEST CRITERIA FOR MID-CYCLE UPDATES?

A. No. Staff believes that an annual update cycle will eliminate most mid-cycle update requests and establishing criteria would have little value. Further, staff recommends that the Commission maintain flexibility to determine when the circumstances may warrant a mid-cycle update.

Issue 3.C: *Should the Commission specify what factors can be updated in mid-cycle? (Such as factors including but not limited to gas price or status of production tax credit.)*

Q. DOES STAFF HAVE A RECOMMENDATION AS TO WHAT FACTORS MAY BE UPDATED MID-CYCLE?

A. No. Staff anticipates that there will be little need for mid-cycle updates and accordingly, little need to identify what factors may be subject to a mid-cycle update. Also, staff recommends that the Commission maintain the maximum amount of flexibility to determine what factors may be subject to a mid-cycle update.

Issue 3.D: *To what extent (if any) can data from IRPs that are in late stages of review and whose acknowledgment is pending be factored into the calculation of avoided cost prices?*

Q. DOES STAFF RECOMMEND THAT THE COMMISSION IDENTIFY AN EXCEPTION TO THE SCHEDULE FOR AVOIDED COST PRICE UPDATES FOR INFORMATION IN AN IRP PROCESS THAT IS ALMOST CONCLUDED?

A. Staff does not recommend that the Commission attempt to identify in advance whether there are any circumstances that may warrant an exception to any schedule for updates decided in this docket.

<u>Issue 3.E</u>: Are there circumstances under which the Renewable Portfolio Implementation Plan should be used in lieu of the acknowledged IRP for purposes of determining renewable resource sufficiency?

Q. DOES STAFF RECOMMEND USING THE RENEWABLE PORTFOLIO IMPLEMENTATION PLAN INSTEAD OF THE IRP TO DETERMINE RESOURCE SUFFICIENCY?

A. No. The Commission concluded in Order No. 11-505 that "[t]he IRP process [is] the appropriate venue for determining when a utility is resource sufficient or deficient." (Order No. 10-488 at 8.) No circumstance warrants revisiting that decision.

<u>SECTION 4: PRICE ADJUSTMENTS FOR SPECIFIC QF CHARACTERISTICS</u>

<u>Issue 4.A</u>. Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology?

Q. DO THE CURRENT STANDARD METHOD AND RENEWABLE METHOD ALLOW ADJUSTMENTS TO THE STANDARD AND RENEWABLE AVOIDED COST PRICES TO ACCOUNT FOR THE ACTUAL CONTRIBUTION TO CAPACITY MADE BY EACH QF RESOURCE TYPE?

A. No. Under the current Standard Method avoided cost prices are based on the capacity contribution of a CCCT, regardless of the QF resource type. Similarly, renewable avoided cost prices created pursuant to Commission Order 11-505 implicitly reflect the capacity contribution of the avoided renewable resource (currently wind for both PGE and PacifiCorp), regardless of the QF resource type.

Q. DOES STAFF PROPOSE TO MODIFY THIS CURRENT PRACTICE?

A. Yes. Staff recommends adjusting the capacity component in both the standard and renewable avoided cost prices to capture the expected capacity contribution of each QF resource type. For the Standard Method, staff proposes multiplying the capacity component currently embedded in the Standard method by a "capacity contribution factor," equal to the expected contribution to peak load of the specific QF resource type. The assumed capacity contribution to peak load is the same one used in the utility's acknowledged IRP for the specific type of generation (wind, solar, etc.).

For the Renewable Method, staff proposes adjusting the capacity component implicit in the renewable on-peak price by the incremental capacity contribution of the specific QF resource type relative to the avoided renewable resource. For a wind QF, this would currently result in no change to its renewable avoided cost prices obtained under the current Renewable Method described in Order No. 11-505 because the next avoidable resource for both PGE and PacifiCorp is a wind resource. For solar and base load QFs, the price adjustment would result in a higher capacity component (and therefore a higher on-peak price) than in the current method. The capacity contribution for each QF resource type used in this adjustment would be the capacity contribution assumed for that resource type in the utility's acknowledged IRP.

Q. HAS STAFF PREPARED SAMPLE CALCULATIONS TO ILLUSTRATE THIS ADJUSTMENT?

A. Yes. Exhibit Staff/102 Bless/1 is a sample calculation for a hypothetical wind QF receiving payments under the standard avoided cost stream. Exhibit Staff/102, Bless/2 is a sample calculation for a hypothetical solar QF receiving payments under the standard avoided cost stream, and Exhibit Staff/102, Bless/3 is a sample calculation for a baseload QF receiving payments on the standard avoided cost stream.

Exhibit Staff/103, Bless/1 is a sample calculation for a hypothetical wind QF receiving payments under the renewable avoided cost price stream. Exhibit Staff/103, Bless/2 is a sample calculation for a hypothetical solar QF receiving payments under the renewable avoided cost price stream, and Exhibit Staff/103, Bless/3 is a sample calculation for a baseload QF receiving payments under the renewable avoided cost price stream.

The numerical values in these exhibits are solely for illustration and are not based on any actual QF. The capacity contribution factors in the exhibits are placeholders and do not imply any staff assumption for actual capacity contribution. As noted above, each utility would use the company specific capacity contribution for each generation type consistent with its IRP.

Q. WILL A QF KNOW, PRIOR TO SIGNING A PPA, HOW ITS AVOIDED COST PRICE STREAM WILL BE PRICE ADJUSTED FOR THE QF'S CAPACITY CONTRIBUTION?

A. Yes. Each utility will have a specific capacity contribution for each resource type and these capacity contributions and the price adjustment calculation will be included in each company's avoided cost price schedule.

Q. HOW WILL THE PROPOSED REVISIONS TO THE STANDARD OREGON METHOD AND RENEWABLE METHOD AFFECT THE AVOIDED COST PRICES RECEIVED BY QFs?

A. A base load QF would see no change under the revised Standard Method because its capacity contribution is treated as equal to the capacity contribution of the avoided resource, a CCCT. This is illustrated in Staff/102, Bless/3. A wind QF selecting the revised Standard Method would see decreased avoided cost prices because its capacity contribution is less than the capacity contribution of the avoided resource, a CCCT. This is illustrated by comparing Staff/102, Bless/1 with Staff/102 Bless/3.

A wind QF selecting prices calculated under the revised Renewable Method would see no change in avoided cost prices because its capacity contribution matches the capacity contribution of the avoided wind resource. This is illustrated in Staff/103 Bless/1. A solar QF selecting prices under the revised Renewable Method would see increased avoided cost prices because its capacity contribution is greater than the capacity contribution of the avoided wind resource. This is illustrated by comparing Staff/103, Bless/1 with Staff/103, Bless/2.

Q. WHY SHOULD THE AVOIDED COST PRICES OF THE STANDARD METHOD AND RENEWABLE METHOD BE ADJUSTED FOR THE CAPACITY CONTRIBUTION OF THE QF RESOURCE?

A. This capacity adjustment addresses the current mismatch between the utilities' avoided capacity payments, which dependent on the characteristics of the utility's avoided resource, and the capacity benefits received from QF resources. Staff believes these adjustments based on the capacity contribution of the QF resources are preferable to addressing this mismatch by lowering the eligibility cap for standard contracts.

Q. HOW DOES STAFF'S MODIFIED OREGON METHOD COMPARE WITH THE MODIFICATION TO THE OREGON METHOD PROPOSED IN IDAHO POWER'S TESTIMONY?

A. The two are similar. However, for wind and solar QFs, Idaho Power would use its modified Oregon Method only for QFs smaller than 100 kW, while the Staff proposal would apply to all QF's eligible for the Standard Contract.

Q. WHY DOES STAFF RECOMMEND ITS MODIFIED STANDARD AND RENEWABLE METHODS OVER OTHER ALTERNATIVES?

A. Staff's recommended methods retain the familiar, straightforward spreadsheet format and do not require QFs to master a complex modeling software product. They both remain transparent methods that provide QFs known and predictable prices that they can use to secure financing. By adjusting the capacity payment to reflect the lower capacity contribution of intermittent resources, they addresses Idaho Power's concerns regarding ratepayer impacts, and more closely approximate the cost to the utility to meet load, but for the purchases from the QF. Since the modeling tools proposed by Idaho Power and PacifiCorp are the same tools they use in their IRPs, the revised Oregon Method and revised Renewable Method proposed by staff capture some of the accuracy of the modeling approaches proposed by Idaho Power and PacifiCorp, and leverage the extensive IRP review process.

Q IS IT APPROPRIATE TO INCLUDE IN THE RENEWABLE AVOIDED COST PRICE THE INTEGRATION COSTS THAT THE UTILITY AVOIDS WITH A PURCHASE FROM A QF?

A. Yes. As indicated in Section 1 of this testimony, Staff recommends including avoided integration costs in the Renewable Method. If QF power enables the utility to avoid integration costs that it would otherwise pay, those avoided costs should be included in the avoided cost price calculation.

Q. IS IT APPROPRIATE TO REQUIRE AN INTERMITTENT QF RESOURCE TO PAY FOR ITS OWN INTEGRATION COSTS?

A. Yes. A QF in the utility's Balancing Authority (BA) would pay the utility's day-ahead, hour-ahead and within-hour integration cost. A QF outside the utility's BA would pay the hour-ahead and in-hour integration cost charged by the transmission provider who is delivering the power to the utility. For example, a QF outside PGE's BA would likely pay BPA hour-ahead and within-hour integration charges.

Q. FOR A WIND QF THAT SELECTS THE RENEWABLE AVOIDED COST RATE OPTION, DOES INCLUSION OF THE AVOIDED INTEGRATION COSTS OFFSET THE QFs PAYMENT OF ITS OWN INTEGRATION COSTS?

A. Yes. However, the offset may not be exact, especially if the avoided resource and the QF resource are located in different balancing areas.

<u>*Issue 4.B:*</u> *Should the costs or benefits of third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?*

Q. SHOULD AVOIDED TRANSMISSION COSTS BE INCLUDED IN STANDARD AND RENEWABLE AVOIDED COST PRICES?

A. Yes. As indicated in Section 1 of this testimony, Staff recommends including avoided transmission costs in both the Standard and Renewable Methods. Avoided transmission costs and avoided integration costs should be treated consistently.

Q. IS IT APPROPRIATE TO REQUIRE AN OFF-SYSTEM QF RESOURCE TO PAY FOR ITS OWN TRANSMISSION COSTS TO DELIVER ITS CAPACITY AND ENERGY TO THE UTILITY?

A. Yes. The utility may specify this in the PPA.

Q. FOR AN OFF-SYSTEM QF, DOES THE INCLUSION OF AVOIDED TRANSMISSION COSTS IN THE AVOIDED COST CALCULATION OFFSET THE QFs PAYMENT OF ITS OWN TRANSMISSION COSTS?

A. Yes. Although the offset may not be exact, especially if the locations of avoided resource and the QF resource are different.

Q. PLEASE SUMMARIZE THE TREATMENT OF AVOIDED INTEGRATION AND TRANSMISSION COSTS UNDER THE PROPOSED REVISIONS TO THE STANDARD AND RENEWABLE.

A. Tables 1 summarizes the components of staff's proposal as to when avoided integration and transmission costs are included in the calculation of avoided cost prices.

TABLE 1: Determination of Avoided Transmission and Integration Costs.

Avoided Resource	Avoided Transmission	Avoided Integration
On-System CCCT	No	No
Off-System CCCT	Yes	No
On-System Wind	No	Yes
Off-System Wind	Yes	Yes

Q. PLEASE SUMMARIZE THE COSTS THAT ARE TO BE PAID BY THE QF UNDER STAFF'S PROPOSALS.

A. Table 2 summarizes the actual integration and transmission costs that are to be paid by the QF. These costs would not appear in the avoided cost price schedule but would be specified in the PPA.

TABLE 2 –Costs Paid by the QF (specify In PPA)

QF Type	Third Party Transmission (regular)	Third Party Transmission (QF in Load Pocket)	Integration
On-system Non-Variable	No	Yes	No

On-System Variable	No	Yes	Yes. QF pays integration costs specific to the purchasing utility
Off-System Non Variable	Yes	No	No
Off-System Variable	Yes	No	Yes. QF pays day-ahead costs specific to the purchasing utility; plus hour-ahead and within-hour costs to the third party transmission provider

Q. DOES A COMPARISON OF TABLE 1 AND TABLE 2 PROVIDE AN INDICATION OF THE BENEFITS AND COSTS TO THE QF?

A. Yes. Table 1 shows the avoided integration and transmission costs a QF can receive. Table 2 shows the transmission and integration costs QF can expect to incur. The QF's net income would be obtained by subtracting its costs in Table 2 from its revenue in Table 1.

Q. PLEASE DEFINE "LOAD POCKET" AS USED IN TABLE 2.

A. For purposes of this testimony, a "load pocket" is when generation in an isolated segment of a utility's system exceeds the utility's load and the utility must use third-party transmission to move the excess generation to load.

Q. PLEASE EXPLAIN IN DETAIL STAFF'S RECOMMENDATION REGARDING TREATMENT OF ACTUAL COSTS TO MOVE QF GENERATION OUT OF A LOAD POCKET.

A. Generally, staff believes that responsibility for the incremental costs to move QF generation out of a load pocket lies with the QF. The methodology used to allocate these costs to the QF depends on whether the costs are properly characterized as "interconnection costs" as defined in 18 C.F.R. 292.101(7). If the costs to move QF generation out of a load pocket are interconnection costs, they are properly assigned to the QF under the Commission's policy regarding allocation of interconnection costs.

If the costs to transmit the QF's energy out of a load pocket are not interconnection costs under 18 C.F.R. 292.101(7), they are properly treated as any other actual cost associated with the purchase of QF power. Meaning, to the extent the actual cost exceeds the utility's avoided costs the incremental costs are borne by the QF. This is because the utility's liability for costs is capped at the utility's avoided costs.

Q. AREN'T THIRD-PARTY TRANSMISSION COSTS DISTINCT FROM INTERCONNECTION COSTS?

A. Ordinarily yes. Staff merely notes the possibility that the third-party transmission costs to move QF generation out of a load pocket may fall within the FERC's definition of "interconnection costs" in the rules implementing PURPA.

Q. WHAT IS THE DEFINITION OF INTERCONNECTION COSTS UNDER PURPA?

A. Under 18 C.F.R. 292.101(7), "interconnection costs" means,

> the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent

> amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

There is some support in FERC orders that FERC intended its definition of "interconnection costs" to be interpreted broadly. In its Notice of Proposed Rulemaking, Small Power Production and Cogeneration-Rates and Exemptions, [the NOPR for the 198 rules implementing PURPA], the Commission explained:

> The costs of transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility. These costs are part of the costs of interconnection, and are the responsibility of the qualifying facility. The electric utility to which the electric energy is transmitted has the obligation to purchase the energy at a rate which reflects the costs that it can avoid as a result of making such a purchase.

Subsequently, in an Order on Rehearing regarding Order No. 888-B, FERC noted that in its rules implementing PURPA, it (FERC) had concluded when it adopted its rules implementing PURPA that the reasonable costs of transmission are included in the definition of interconnection costs. (Order No. 888-B, *Order on Rehearing*, 81 FERC 61248, 1997 WL 833250 at pp 17-18) ("[I]n Order No. 69, Small Power Production and Cogeneration Facilities, Regulations Implementing section 210 of the Public Utility Regulatory Policies Act of 1978 * * * the Commission defined 'interconnection costs' as the reasonable costs of 'transmission.'").

Q. HOW DOES THE COMMISSION ALLOCATE INTERCONNECTION COSTS?

A. Generally, a generator pays the costs to interconnect with a utility, unless the interconnection provides system benefits, in which case interconnection costs are appropriately shared with all customers. (See OAR 860-029-0060.)

Q. ARE AVOIDED INTERCONNECTION COSTS INCLUDED IN THE AVOIDED COST CALCULATION?

A. Yes. In Order No. 07-360, the Commission noted that transmission and distribution upgrade costs that can be avoided or deferred as a result of the QF's location should be recognized in an adjustment to non-standard avoided costs in negotiated contracts. (Order No. 07-360 at 27.)

Q. DOES THE CHARACTERIZATION OF THE COSTS TO TRANSMIT QF ENERGY OUT OF A LOAD POCKET AS INTERCONNECTION COSTS OR NON-INTERCONNECTION COSTS AFFECT STAFF'S RECOMMENDATION AS TO WHO IS RESPONSIBLE FOR THOSE COSTS?

A. No. Under either the Commission's policy regarding allocation of costs to interconnect a QF or staff's recommendation as to who should bear incremental third-party transmission costs, the costs are appropriately allocated to the QF.

Issue 4.C. *How should the seven factors of 18 C.F.R. 292.304(e)(2) be taken into account?*

Q. ARE STAFF'S PROPOSED PRICE ADJUSTMENTS TO STANDARD AND RENEWABLE AVOIDED COST PRICES TO ACCOUNT FOR DIFFERENT CAPACITY CONTRIBUTIONS OF DIFFERENT RESOURCE TYPES BASED ON THE SEVEN FERC FACTORS?

A. No. Staff's proposed adjustments to differentiate avoided cost prices by categories of QF resource types are predicated on authority in 18 C.F.R. 202.304(c)(3)(ii), which provides that "standard rates for purchases [from design facilities with a design capacity of less than 100 kilowatts or more than 100 kilowatts] * * * [m]ay differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies."

Q. SHOULD THE AVOIDED COST PRICES IN THE STANDARD AND STANDARD RENEWABLE CONTRACT FACTOR IN THE SEVEN FERC FACTORS OF 18 CFR 292.304(E)(2)?

A. No. The seven FERC factors should be reserved to negotiation of non-standard QF contracts.

Q. WHAT IS THE AUTHORITY FOR STAFF'S PROPOSAL TO INCLUDE AVOIDED INTEGRATION AND TRANSMISSION COSTS IN THE CALCULATION OF AVOIDED COST RATE PRICES?

A. The Commission has already allowed avoided transmission costs in the calculation of avoided cost prices. FERC has clarified that avoided transmission costs may be included in the calculation of avoided costs. *California Public Utilities Commission, Order Granting Clarification and Dismissing* Rehearing, 133 FERC 61,059 (2010 WL 4144227 at 19.) FERC has also clarified that costs to integrate intermittent resources are costs of transmission. Staff recommends that the Commission clarify that avoided transmission and costs to integrate intermittent resources are properly included in the calculation of avoided cost prices. Staff also recommends that the Commission clarify that the calculation of avoided cost prices does not include offsets for actual costs.

SECTION 5: ELIGIBILITY ISSUES

Issue 5.A: *Should the commission change the 10 MW cap for the standard contract?*

Q. DOES STAFF RECOMMEND CHANGING THE 10 MW ELIGIBILITY CAP FOR THE STANDARD CONTRACT?

A. No. Staff recommends keeping the eligibility cap at 10 MW. This recommendation is predicated on the modifications to the Standard Method and Renewable Method described in Sections 1, 2 and 4.

Q. HOW DOES STAFF RESPOND TO THE CONCERNS RAISED BY IDAHO POWER REGARDING ADVERSE IMPACTS ON RATEPAYERS?

A. Idaho Power testified that QFs under the current cost methodology are receiving payments in excess of the actual avoided cost, and those costs are being passed on to ratepayers. We reviewed that testimony and observed that the majority of those contracts contain price schedules were calculated using the SAR method. The SAR method is not structured with a sufficiency and deficiency period. It results in QFs receiving a higher price in the early years, compared to the market price that QFs receive during the sufficiency period under the Oregon Method.

PGE and PacifiCorp raised the same concerns. Staff response to these concerns is the same; all avoided cost prices should, to the extent practical, reflect true avoided costs. In short, if the standard avoided cost price method does not hold ratepayers harmless then the best remedy is to adopt a more accurate calculation method, rather than lower the eligibility cap.

Q. DOES STAFF BELIEVE THAT RATEPAYERS ARE PROTECTED ADEQUATELY WITH A 10 MW CAP IN OREGON?

A. Yes. In our testimony above we proposed two significant changes to the standard avoided cost methodology. First, we propose adjusting the capacity component to take into account the different capacity contributions of wind, solar and other QF types. Second, we propose adjustments to the avoided cost price for avoided wind integration and transmission costs and adjustments to the standard contract for actual wind integration and transmission costs. Some of those adjustments occur not in the avoided cost calculation but in the PPA, but the net result is the same: the overall price paid to QFs now takes into account some of the problems raised by the utilities.

Q. WHY DOES STAFF PREFER THIS APPROACH TO THE LOWER CAP PROPOSED BY THE UTILITIES?

A. We conclude that the harm identified by utilities is better addressed with modifications to the standard avoided price calculations as opposed to limitations on their applicability.

Q. IF NO MODIFICATIONS TO THE PRICE CALCULATION METHODOLOGY ARE ADOPTED, WHAT IS STAFF'S RECOMMENDATION REGARDING THE ELIGIBILITY CAP?

A. If no modifications are adopted, then staff recommends a 3 MW cap for all QF types, as also proposed by PacifiCorp. Staff believes that the lower cap is necessary to minimize the impact of the mismatch between avoided cost payments and the actual avoided cost.

Q. WHAT IS THE BASIS FOR THE SELECTION OF 3 MW?

A. Staff reviewed the wind turbine models currently offered by Vestas and General Electric. Current model turbines available from these two vendors range from 1.8 MW up to 3 MW, with higher ratings soon to be available.[4] Staff concluded that 3 MW would be the largest size QF that might be a "single machine" facility. Staff reasoned that a large, sophisticated developer capable of procuring the latest offering from these vendors is likely capable of negotiating a PPA. Staff reasoned that the smaller developers who are at a disadvantage in negotiating are less likely to be procuring the latest and most advanced turbine technology. Staff realizes that some very sophisticated and capable negotiators may propose facilities smaller than 3 MW, and some local community-based projects may still be larger than 3 MW. As with any regulatory threshold, there can be outliers. However, Staff concluded that matching the threshold to the range of wind turbines currently offered by two of

[4] www.vestas.com; www.ge-energy.com/wind

the best known vendors is reasonable.[5] Staff also notes that the solar, biomass and small hydro in PGE, PacifiCorp and Idaho Power's current portfolios are, for the most part, well under 3 MW.

Issue 5.B: *What should be the criteria to determine whether a QF is a single QF for purposes of eligibility for the standard contract?*

Q. SHOULD THE COMMISSION ADOPT MORE DETAILED "SINGLE FACILITY" CRITERIA?

A. No. In Docket No. UM 1129, the Commission adopted a partial stipulation specifying criteria for determining when a facility is a single facility under PURPA.[6] (Order No. 06-586.) The criteria specify that to be a single-facility, a QF with multiple sites must be owned by the "same person(s) or affiliated person(s)" and that the multiple sites must be located within a five-mile radius of each other. (Order No. 06-586, App B at p 11.) Staff does not recommend that the Commission adopt additional criteria in this docket.

Issue 5.C: *Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?*

Q. HOW DOES RESOURCE TECHNOLOGY AFFECT THE SIZE OF THE STANDARD CONTRACT CAP OR CRITERIA FOR SINGLE QF?

[5] Staff acknowledges that turbine technology will continue to advance, and other vendors may offer larger sizes sooner than GE and Vestas. Our recommendation is not intended to imply an exhaustive account of all wind turbine designs. Our intent was solely to propose a reasonable basis for a cap lower than 10 MW. The current 10 MW cap with the proposed calculation modifications remains staff's first recommendation.

[6] The stipulation is found at http://edocs.puc.state.or.us/efdocs/HAO/um1129hao13271.pdf

A. Staff recommends a 10 MW cap, regardless of resource type. Staff does not recommend different caps for different resource types.

<u>Issue 5.D</u>: *Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell RECs in another state?*

Q. SHOULD QFs BE ELIGIBLE FOR OREGON'S RENEWABLE AVOIDED COST PRICE IF THE QF OWNER WILL SELL THE RECs IN ANOTHER STATE?

A. During the sufficiency period, the QF is receiving only market price for its energy, even if it has elected the renewable avoided cost price stream, and should be free to sell RECs in another state. In order to receive renewable avoided cost prices in Oregon during the purchasing utility's deficiency periods, the QF must agree to transfer its RECs to the purchasing utility during the deficiency periods. In this circumstance, a QF would be precluded from selling its RECs (at least those associated with energy transferred to the Oregon utility) out of state.

SECTION 6: LEGALLY ENFORCEABLE OBLIGATION, CONTRACT TERM AND MECHANICAL AVAILABILITY

Issue 6.B: *When is there a legally enforceable obligation?*

Q. WHEN SHOULD THERE BE A LEGALLY ENFORCEABLE OBLIGATION

A. Staff concurs with the testimony of PacifiCorp. PacifiCorp's Schedule 37 includes a list of steps in reaching a signed PPA. At step B.5, the utility sends the QF a "final draft contract." When the QF approves that final draft, there is a legally enforceable obligation, even if the utility has not yet signed. (PAC/200, Griwold/29-31.)

Q. DOES THIS POSITION APPLY TO THE OTHER TWO OREGON UTILITIES?

A. Yes, Idaho Power's Schedule 85 and PGE's Schedule 201 have analogous language describing the power purchase agreement process.

Issue 6.I: *What is the appropriate contract term? What is the appropriate duration for the fixed portion of the contract?*

Q. WHAT IS THE APPROPRIATE CONTRACT TERM AND DURATION FOR THE FIXED PRICE PORTION OF THE CONTRACT?

A. Staff recommends retaining the current policy of a 20 year maximum contract with the fixed price option in effect for at most 15 years.

Q. THE UTILITIES PROPOSE LIMITING THE FIXED PRICE PORTION OF THE CONTRACT TO 10 YEARS. WHY DOES STAFF RECOMMEND RETAINING THE CURRENT POLICY?

A. The issue of contract term was extensively discussed in Docket No. UM 1129. In that docket, the Commission determined that a 15-year fixed portion was the appropriate balance between ratepayer risk and the certain and predictable prices sought by QFs. The issues are the same today, so staff recommends the same conclusion.

Q. SHOULD THE COMMISSION MODIFY ITS POLICIES FOR THE MECHANICAL AVAILABILITY GUARANTEE (MAG)?

A. Yes. Staff recommends that the Commission place parameters on the terms of the MAG and on the penalties for failure to comply.

Q. PLEASE REVIEW THE MAG'S HISTORY AND PURPOSE.

A. Power purchase agreements (PPAs) have traditionally included an output delivery guarantee. This guarantee helps the utility and benefits ratepayers because the utility needs to factor the expected power from QFs into its short range and long range planning and scheduling. If the QF does not produce the expected power, the utility may need to find replacement power at a higher price than it would have incurred with more advance notice.

In Docket No. UM 1129, parties realized that wind facilities cannot provide a traditional guarantee because they are dependent on the wind. A mechanical availability guarantee was proposed as a way of ensuring that QFs would at least guarantee the performance of the one variable they have control over, namely the generating equipment. The Commission chose not to adopt a MAG in UM 1129, but it directed utilities to adopt the MAG in Order 07-360.

Q. DO ALL THREE OREGON UTILITIES PLACE THE SAME MAG IN THEIR STANDARD CONTRACT?

A. No. The Commission was not prescriptive regarding the terms of the MAG. Each utility specified different mechanical availability targets in their standard contracts. The utilities also vary as to allowance for planned maintenance and penalty for failure to meet the MAG.

Q. WHY DID STAKEHOLDERS RAISE THE MAG AS AN ISSUE FOR THIS DOCKET?

A. The Commission received a complaint[7] regarding PGE's implementation of the MAG. PGE's MAG requires 90% mechanical availability in the first year of operations and 95% in subsequent years (the highest availability targets of the three Oregon utilities). Percentage availability is calculated on an average annual basis. The plaintiff states that PGE's MAG is not reasonable because (1) it counts all wind turbine downtime as "unavailable," with no allowance for planned maintenance, and (2) PGE's standard contract specifies that PGE can terminate the contract if the QF fails to meet the annual availability guarantee.

Q. IS THERE AN INDUSTRY STANDARD FOR ANNUAL WIND TURBINE AVAILABILITY?

A. No. Staff searched available information from the American Wind Energy Association and from major wind turbine vendors and found nothing that we could call an industry standard.

Q. DID STAFF CONSIDER THE INDUSTRY STANDARD DESCRIBED IN PGE'S SUPPLEMENTAL TESTIMONY OF FEBRUARY 19, 2013?

[7] The complaint is docketed as UM 1566. That docket will proceed on its own schedule for purposes or resolving the dispute between PaTu Wind Farm and PGE. However, we are addressing the generic question of future MAG implementation in docket UM 1610.

A. Yes. I reviewed the references provided in PGE's testimony. Those references included a 2006 paper by Stoel Rives law firm describing wind power contracting practices generally, an example of an availability calculation published by Huron wind facility in Canada, and maintenance information from General Electric and Vestas. (PGE/200, Macfarlane-Bettis/4-5.) These references included statements about availability factors and the performance that the vendor may guarantee with the purchase of their vendor-supplied maintenance program, but the availability factors in these references were characterized as examples, not an industry standard.

Q. DID UTILITIES PROVIDE INFORMATION ABOUT THE MECHANICAL AVAILABILITY THEY ACHIEVE AT THEIR OWN UTILITY OWNED WIND FARMS?

A. Yes. PGE testified that its own wind farm exceeds the annual availability factors in their MAGs. (PGE/200, Macfarlane-Bettis/3-4.)

Q. DOES STAFF RECOMMEND THAT THE MAG REQUIRE QFS TO REACH THE SAME MECHANICAL AVAILABILITY AS THE UTILITIES' OWN WIND FACILITIES?

A. Staff considers it unrealistic to require in a contract that the QF reach the same availability as the utilities. Utilities have advantages that QFs smaller than 10 MW lack. For example, the utilities have the resources to maintain a dedicated maintenance staff and the ability to coordinate staff training and scheduled outages among several utility owned facilities. The utilities can maintain a larger inventory of spare parts to fix emergent problems quickly. QFs should be encouraged to use best maintenance practices, but the utilities have more economies of scale.

Q. DOES STAFF RECOMMEND THAT THE COMMISSION PRESCRIBE SPECIFIC AVERAGE ANNUAL AVAILABILITY PERCENTAGES?

A. No. Without an accepted industry standard, staff does not believe there is a sound basis for the Commission to prescribe a percentage.

Q. WHAT PARAMETERS DOES STAFF RECOMMEND, AND WHY?

A. Staff recommends that the Commission adopt parameters for planned maintenance allowance and penalty for noncompliance, because those are the two elements that have been problematic.

Q. WHAT DOES STAFF RECOMMEND FOR PLANNED MAINTENANCE?

A. PGE, in its testimony, proposed an allowance of 200 hours planned maintenance per year, per turbine, that would not count against the QFs availability factor. PGE considers maintenance “planned” if the QF provides the utility with 90 days advance notice. (PGE/200, Macfarlane/Bettis/2-3.) PacifiCorp testified that its current definition of availability allows 240 hours of scheduled maintenance per turbine, per year, that would not count against the QFs overall annual availability. It proposes lowering this allowance to 60 hours per turbine, per year. (PAC/300, Griswold/5.)

Q. WOULD THE 60 HOUR/YEAR ALLOWANCE SUGGESTED BY PACIFICORP BE REASONABLE?

A. The recommended level of scheduled maintenance varies with turbine vendor, model, age and operating conditions. It may be possible to properly maintain a wind facility with 60 hours of planned maintenance per year, as PacifiCorp suggests. But the purpose of scheduled maintenance is to prevent unexpected failures that come at the most expensive time, take longer to fix, and are hard to plan for. Preventive maintenance is expensive and QFs have no incentive to schedule excessive maintenance. For this reason, I recommend the Commission err on the high side regarding the maintenance allowance. The 90-day prior notice provisions in PGE's and PacifiCorp's guarantee allow the utility to plan ahead and prevent QFs from claiming that an emergent failure was scheduled maintenance. Staff concludes that 200 hours scheduled maintenance per turbine, per year, is a reasonable parameter for scheduled maintenance that does not count against overall mechanical availability.

Q. IS CONTRACT TERMINATION A REASONABLE PENALTY FOR FAILURE TO MEET THE MAG?

A. No, contract termination is too severe. A 300 MW wind facility can experience an extended outage on one turbine and still achieve a high overall availability factor, but a wind QF with four 2MW turbines can fall short of its MAG with one mechanical failure. Staff recommends a monetary penalty based on the cost of replacement power, rather than termination.

Q. DOES STAFF PROPOSE A CERTAIN FORMULA FOR CALCULATING THE PENALTY?

A. No. However, Staff recommends that the Commission order that any penalty must be based on the failure to meet the annual limit on scheduled maintenance and be based on actual net replacement power costs for the incremental unavailable hours that exceed the aggregate annual mechanical unavailability limit for all turbines.

Q. ARE THERE CIRCUMSTANCES WHEN THE UTILITY MIGHT BE ALLOWED TO TERMINATE THE CONTRACT FOR FAILURE TO MEET THE MAG?

A. Yes, if a QF is chronically unable to meet its mechanical availability target, even with reasonable allowance for planned maintenance. Staff suggests the utility be allowed to terminate the contract if the QF fails to comply with the MAG for three consecutive years.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1610
WITNESS: ADAM BLESS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

March 18, 2013

WITNESS QUALIFICATION STATEMENT

NAME:	ADAM BLESS
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	SENIOR UTILITY ANALYST ENERGY RESOURCES & PLANNING
ADDRESS:	550 CAPITOL STREET NE SUITE 215, SALEM, OREGON 97301-2115.
EDUCATION:	In 1975 I received a Bachelor of Science degree in Mathematics from Massachusetts Institute of Technology. In 1978 I received a Master of Science in Nuclear Engineering from the University of Washington.
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission since May of 2010. From December 2011 to the present, I have been the Energy Resource and Planning Division's assigned staff to avoided cost calculations under PURPA. From 1989 to 2010 I was an Energy Facility Analyst for the Oregon Department of Energy (ODOE), serving lead review staff for the siting of Energy Facility Siting Council jurisdictional energy facilities as defined at ORS 469.300(11). From 1989 to 2005 I also served as the State's on-site resident inspector at Portland General Electric's Trojan Nuclear Plant. From 1978 to 1989 I was employed by Commonwealth Edison of Chicago Illinois, serving for two years in that company's Statistical Research department and for twelve years as staff engineer at the Company's Zion Nuclear Plant.

CASE: UM 1610
WITNESS: ADAM BLESS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Response Testimony

March 18, 2013

Exhibit 102 **Staff/102**

Standard Avoided Cost Prices: Wind QF Resource **Bless/1**

	A	B	C	D	E	F	G
	Standard Avoided Resource			Wind QF Resource			
Year	Capital Cost Allocated to Capacity On-Peak Hours $/MWh	Capital Cost Allocated to Energy All Hours $/MWh	Fuel Cost All Hours $/MWh	Contribution to Peak %	Capacity Payment On-Peak Hours $/MWh = A x D	QF Prices On-Peak $/MWh = B+C+E	 Off-Peak $/MWh = B+C
2013	Market Based Prices 2013 through 2015					$36.13	$26.69
2014						$39.31	$29.69
2015						$42.56	$31.44
2016	$23.57	$2.82	$34.03	5%	$1.18	$38.03	$36.85
2017	$24.02	$2.88	$36.26	5%	$1.20	$40.34	$39.14
2018	$24.48	$2.94	$39.18	5%	$1.22	$43.34	$42.12
2019	$24.92	$2.99	$41.97	5%	$1.25	$46.21	$44.96
2020	$25.34	$3.03	$41.06	5%	$1.27	$45.36	$44.09
2021	$25.80	$3.09	$43.36	5%	$1.29	$47.74	$46.45
2022	$26.26	$3.15	$47.26	5%	$1.31	$51.72	$50.41
2023	$26.74	$3.21	$49.21	5%	$1.34	$53.76	$52.42
2024	$27.22	$3.26	$48.37	5%	$1.36	$52.99	$51.63
2025	$27.71	$3.32	$49.90	5%	$1.39	$54.61	$53.22
2026	$28.20	$3.38	$52.27	5%	$1.41	$57.06	$55.65
2027	$28.74	$3.45	$54.36	5%	$1.44	$59.25	$57.81
2028	$29.29	$3.52	$55.96	5%	$1.46	$60.94	$59.48
2029	$29.84	$3.58	$57.28	5%	$1.49	$62.35	$60.86
2030	$30.41	$3.65	$57.91	5%	$1.52	$63.08	$61.56
2031	$31.02	$3.72	$58.74	5%	$1.55	$64.01	$62.46
2032	$31.61	$3.79	$59.86	5%	$1.58	$65.23	$63.65
2033	$32.21	$3.87	$60.97	5%	$1.61	$66.45	$64.84
2034	$32.86	$3.94	$62.22	5%	$1.64	$67.80	$66.16
2035	$33.48	$4.01	$63.34	5%	$1.67	$69.02	$67.35

Notes:

A, B, C Based on Pacificorp Advice 12-005, filed March 2, 2012

D Percentage of hours resource is available for contribution to peak, assumed in the utility's IRP

Exhibit 102 **Staff/102**

Standard Avoided Cost Prices: Solar QF Resource **Bless/2**

	A	B	C	D	E	F	G
	Standard Avoided Resource			Solar QF Resource			
Year	Capital Cost Allocated to Capacity On-Peak Hours $/MWh	Capital Cost Allocated to Energy All Hours $/MWh	Fuel Cost All Hours $/MWh	Contribution to Peak %	Capacity Payment On-Peak Hours $/MWh = A x D	QF Prices On-Peak $/MWh = B+C+E	 Off-Peak $/MWh = B+C
2013	Market Based Prices 2013 through 2015					$36.13	$26.69
2014						$39.31	$29.69
2015						$42.56	$31.44
2016	$23.57	$2.82	$34.03	30%	$7.07	$43.92	$36.85
2017	$24.02	$2.88	$36.26	30%	$7.21	$46.35	$39.14
2018	$24.48	$2.94	$39.18	30%	$7.34	$49.46	$42.12
2019	$24.92	$2.99	$41.97	30%	$7.48	$52.44	$44.96
2020	$25.34	$3.03	$41.06	30%	$7.60	$51.69	$44.09
2021	$25.80	$3.09	$43.36	30%	$7.74	$54.19	$46.45
2022	$26.26	$3.15	$47.26	30%	$7.88	$58.29	$50.41
2023	$26.74	$3.21	$49.21	30%	$8.02	$60.44	$52.42
2024	$27.22	$3.26	$48.37	30%	$8.17	$59.80	$51.63
2025	$27.71	$3.32	$49.90	30%	$8.31	$61.53	$53.22
2026	$28.20	$3.38	$52.27	30%	$8.46	$64.11	$55.65
2027	$28.74	$3.45	$54.36	30%	$8.62	$66.43	$57.81
2028	$29.29	$3.52	$55.96	30%	$8.79	$68.27	$59.48
2029	$29.84	$3.58	$57.28	30%	$8.95	$69.81	$60.86
2030	$30.41	$3.65	$57.91	30%	$9.12	$70.68	$61.56
2031	$31.02	$3.72	$58.74	30%	$9.31	$71.77	$62.46
2032	$31.61	$3.79	$59.86	30%	$9.48	$73.13	$63.65
2033	$32.21	$3.87	$60.97	30%	$9.66	$74.50	$64.84
2034	$32.86	$3.94	$62.22	30%	$9.86	$76.02	$66.16
2035	$33.48	$4.01	$63.34	30%	$10.04	$77.39	$67.35

Notes:

A, B, C Based on Pacificorp Advice 12-005, filed March 2, 2012

D Percentage of hours resource is available for contribution to peak, assumed in the utility's IRP

Exhibit 102
Standard Avoided Cost Prices: Baseload QF Resource

	A	B	C	D	E	F	G
	Standard Avoided Resource			Baseload QF Resource			
Year	Capital Cost Allocated to Capacity On-Peak Hours $/MWh	Capital Cost Allocated to Energy All Hours $/MWh	Fuel Cost All Hours $/MWh	Contribution to Peak %	Capacity Payment On-Peak Hours $/MWh = A x D	QF Prices On-Peak $/MWh = B+C+E	 Off-Peak $/MWh = B+C
2013	Market Based Prices 2013 through 2015					$36.13	$26.69
2014						$39.31	$29.69
2015						$42.56	$31.44
2016	$23.57	$2.82	$34.03	100%	$23.57	$60.42	$36.85
2017	$24.02	$2.88	$36.26	100%	$24.02	$63.16	$39.14
2018	$24.48	$2.94	$39.18	100%	$24.48	$66.60	$42.12
2019	$24.92	$2.99	$41.97	100%	$24.92	$69.88	$44.96
2020	$25.34	$3.03	$41.06	100%	$25.34	$69.43	$44.09
2021	$25.80	$3.09	$43.36	100%	$25.80	$72.25	$46.45
2022	$26.26	$3.15	$47.26	100%	$26.26	$76.67	$50.41
2023	$26.74	$3.21	$49.21	100%	$26.74	$79.16	$52.42
2024	$27.22	$3.26	$48.37	100%	$27.22	$78.85	$51.63
2025	$27.71	$3.32	$49.90	100%	$27.71	$80.93	$53.22
2026	$28.20	$3.38	$52.27	100%	$28.20	$83.85	$55.65
2027	$28.74	$3.45	$54.36	100%	$28.74	$86.55	$57.81
2028	$29.29	$3.52	$55.96	100%	$29.29	$88.77	$59.48
2029	$29.84	$3.58	$57.28	100%	$29.84	$90.70	$60.86
2030	$30.41	$3.65	$57.91	100%	$30.41	$91.97	$61.56
2031	$31.02	$3.72	$58.74	100%	$31.02	$93.48	$62.46
2032	$31.61	$3.79	$59.86	100%	$31.61	$95.26	$63.65
2033	$32.21	$3.87	$60.97	100%	$32.21	$97.05	$64.84
2034	$32.86	$3.94	$62.22	100%	$32.86	$99.02	$66.16
2035	$33.48	$4.01	$63.34	100%	$33.48	$100.83	$67.35

Notes:

A, B, C	Based on Pacificorp Advice 12-005, filed March 2, 2012
D	Percentage of hours resource is available for contribution to peak, assumed in the utility's IRP

Explanation of Tables 1, 2 and 3 in Exhibit Staff/102

This exhibit shows staff's proposed adjustment to the Standard (nonrenewable) avoided cost calculations for hypothetical wind, solar and base load QFs.

Staff used values from PacifiCorp's avoided cost price update of March 2012. However, these examples are intended to demonstrate the calculation method, not to represent a specific price.

Table 1 illustrates a Standard Avoided Cost Calculation for a hypothetical wind QF. Consistent with current practice, the avoided cost price schedule includes an on-peak and off-peak price.

The avoided resource is a combined cycle combustion turbine (CCCT). As is done in the current Oregon Method, a portion of its capital costs are assigned to capacity and the remainder is assigned to energy. Fuel costs for the CCCT are also calculated consistent with current practice. Column A shows the capital costs assigned to capacity, Column B shows the capital costs assigned to energy, and column C shows the CCCT fuel costs.

The off-peak price is simply the avoided energy costs, consisting of the fuel cost plus capital costs assigned to energy. The sum is shown at column G and is identical to the current Oregon Method.

The on-peak price includes the same energy costs plus an avoided capacity cost. For this example, we assume that a wind QF contributes 5% of its nameplate capacity to peak load. The 5% does not represent any real wind plant and is a placeholder used for illustration. The actual peak load capacity contribution will be taken from the utility's IRP.

In column E, we multiply the capital cost allocated to capacity (column A) by this assumed capacity contribution percentage. The product is the avoided capacity cost included in the on-peak price. In column F we add this capacity cost to the energy costs (column G) to arrive at the total on-peak price.

Table 2 is the same calculation, with an assumed 30% capacity contribution to peak load for a solar QF. Table 3 is the calculation with a base load QF. Since the base load QF is assumed to have the same capacity contribution as the avoided CCCT resource, it results in the same avoided cost price that would apply under the current Standard Oregon Method.

CASE: UM 1610
WITNESS: ADAM BLESS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Response Testimony

March 18, 2013

Exhibit 103 **Staff/103**
Renewable Avoided Cost Prices: Wind QF Resource **Bless/1**

	A	B	C	D	E	F	G	H	I
	Renewable Avoided Resource		Capacity		Wind QF Resource				
Year	Avoided Cost On-Peak $/MWh	Avoided Cost Off-Peak $/MWh	Capital Cost Allocated to Capacity (On-Peak Hours) $/MWh	Renewable Proxy Resource Contribution to Peak %	QF Resource Contribution to Peak %	QF Incremental Capacity Contribution to Peak % = E - D	QF Capacity Adder $/MWh = C x F	QF Prices On-Peak $/MWh = A + G	QF Prices Off-Peak $/MWh = B
2013	Market Based Prices 2013 through 2017							$36.13	$26.69
2014								$39.31	$29.69
2015								$42.56	$31.44
2016								$46.06	$33.34
2017								$49.56	$35.14
2018	$68.27	$50.93	$24.48	5%	5%	0%	$0.00	$68.27	$50.93
2019	$68.45	$53.14	$24.92	5%	5%	0%	$0.00	$68.45	$53.14
2020	$69.52	$54.06	$25.34	5%	5%	0%	$0.00	$69.52	$54.06
2021	$69.00	$57.41	$25.80	5%	5%	0%	$0.00	$69.00	$57.41
2022	$70.15	$58.54	$26.26	5%	5%	0%	$0.00	$70.15	$58.54
2023	$71.36	$59.72	$26.74	5%	5%	0%	$0.00	$71.36	$59.72
2024	$72.45	$60.97	$27.22	5%	5%	0%	$0.00	$72.45	$60.97
2025	$73.68	$62.17	$27.71	5%	5%	0%	$0.00	$73.68	$62.17
2026	$74.94	$63.37	$28.20	5%	5%	0%	$0.00	$74.94	$63.37
2027	$76.09	$64.94	$28.74	5%	5%	0%	$0.00	$76.09	$64.94
2028	$77.58	$66.14	$29.29	5%	5%	0%	$0.00	$77.58	$66.14
2029	$78.79	$67.71	$29.84	5%	5%	0%	$0.00	$78.79	$67.71
2030	$80.15	$69.11	$30.41	5%	5%	0%	$0.00	$80.15	$69.11
2031	$81.92	$70.19	$31.02	5%	5%	0%	$0.00	$81.92	$70.19
2032	$83.23	$71.98	$31.61	5%	5%	0%	$0.00	$83.23	$71.98
2033	$84.62	$73.58	$32.21	5%	5%	0%	$0.00	$84.62	$73.58
2034	$86.28	$75.15	$32.86	5%	5%	0%	$0.00	$86.28	$75.15
2035	$87.77	$76.77	$33.48	5%	5%	0%	$0.00	$87.77	$76.77

Notes:
A&B Based on Pacificorp compliance filing for Order 11-505 (UM 1396)
C Based on Pacificorp Advice 12-005, filed March 2, 2012
D&E Percentage of hours resources are available for contribution to peak, assumed in the utility's IRP

	A	B	C	D	E	F	G	H	I
	Renewable Avoided Resource		Capacity		Solar QF Resource				
Year	Avoided Cost On-Peak $/MWh	Avoided Cost Off-Peak $/MWh	Capital Cost Allocated to Capacity (On-Peak Hours) $/MWh	Renewable Proxy Resource Contribution to Peak %	QF Resource Contribution to Peak %	QF Incremental Capacity Contribution to Peak % = E - D	QF Capacity Adder $/MWh = C x F	QF Prices On-Peak $/MWh = A + G	QF Prices Off-Peak $/MWh = B
2013	Market Based Prices 2013 through 2017							$36.13	$26.69
2014								$39.31	$29.69
2015								$42.56	$31.44
2016								$46.06	$33.34
2017								$49.56	$35.14
2018	$68.27	$50.93	$24.48	5%	30%	25%	$6.12	$74.39	$50.93
2019	$68.45	$53.14	$24.92	5%	30%	25%	$6.23	$74.68	$53.14
2020	$69.52	$54.06	$25.34	5%	30%	25%	$6.34	$75.86	$54.06
2021	$69.00	$57.41	$25.80	5%	30%	25%	$6.45	$75.45	$57.41
2022	$70.15	$58.54	$26.26	5%	30%	25%	$6.57	$76.72	$58.54
2023	$71.36	$59.72	$26.74	5%	30%	25%	$6.69	$78.05	$59.72
2024	$72.45	$60.97	$27.22	5%	30%	25%	$6.81	$79.26	$60.97
2025	$73.68	$62.17	$27.71	5%	30%	25%	$6.93	$80.61	$62.17
2026	$74.94	$63.37	$28.20	5%	30%	25%	$7.05	$81.99	$63.37
2027	$76.09	$64.94	$28.74	5%	30%	25%	$7.19	$83.28	$64.94
2028	$77.58	$66.14	$29.29	5%	30%	25%	$7.32	$84.90	$66.14
2029	$78.79	$67.71	$29.84	5%	30%	25%	$7.46	$86.25	$67.71
2030	$80.15	$69.11	$30.41	5%	30%	25%	$7.60	$87.75	$69.11
2031	$81.92	$70.19	$31.02	5%	30%	25%	$7.76	$89.68	$70.19
2032	$83.23	$71.98	$31.61	5%	30%	25%	$7.90	$91.13	$71.98
2033	$84.62	$73.58	$32.21	5%	30%	25%	$8.05	$92.67	$73.58
2034	$86.28	$75.15	$32.86	5%	30%	25%	$8.22	$94.50	$75.15
2035	$87.77	$76.77	$33.48	5%	30%	25%	$8.37	$96.14	$76.77

Notes:

A&B Based on Pacificorp compliance filing for Order 11-505 (UM 1396)

C Based on Pacificorp Advice 12-005, filed March 2, 2012

D&E Percentage of hours resources are available for contribution to peak, assumed in the utility's IRP

	A	B	C	D	E	F	G	H	I
	Renewable Avoided Resource		Capacity		Baseload QF Resource				
Year	Avoided Cost On-Peak $/MWh	Avoided Cost Off-Peak $/MWh	Capital Cost Allocated to Capacity (On-Peak Hours) $/MWh	Renewable Proxy Resource Contribution to Peak %	QF Resource Contribution to Peak %	QF Incremental Capacity Contribution to Peak % = E - D	QF Capacity Adder $/MWh = C x F	QF Prices On-Peak $/MWh = A + G	QF Prices Off-Peak $/MWh = B
2013	Market Based Prices 2013 through 2017							$36.13	$26.69
2014								$39.31	$29.69
2015								$42.56	$31.44
2016								$46.06	$33.34
2017								$49.56	$35.14
2018	$68.27	$50.93	$24.48	5%	100%	95%	$23.26	$91.53	$50.93
2019	$68.45	$53.14	$24.92	5%	100%	95%	$23.67	$92.12	$53.14
2020	$69.52	$54.06	$25.34	5%	100%	95%	$24.07	$93.59	$54.06
2021	$69.00	$57.41	$25.80	5%	100%	95%	$24.51	$93.51	$57.41
2022	$70.15	$58.54	$26.26	5%	100%	95%	$24.95	$95.10	$58.54
2023	$71.36	$59.72	$26.74	5%	100%	95%	$25.40	$96.76	$59.72
2024	$72.45	$60.97	$27.22	5%	100%	95%	$25.86	$98.31	$60.97
2025	$73.68	$62.17	$27.71	5%	100%	95%	$26.32	$100.00	$62.17
2026	$74.94	$63.37	$28.20	5%	100%	95%	$26.79	$101.73	$63.37
2027	$76.09	$64.94	$28.74	5%	100%	95%	$27.30	$103.39	$64.94
2028	$77.58	$66.14	$29.29	5%	100%	95%	$27.83	$105.41	$66.14
2029	$78.79	$67.71	$29.84	5%	100%	95%	$28.35	$107.14	$67.71
2030	$80.15	$69.11	$30.41	5%	100%	95%	$28.89	$109.04	$69.11
2031	$81.92	$70.19	$31.02	5%	100%	95%	$29.47	$111.39	$70.19
2032	$83.23	$71.98	$31.61	5%	100%	95%	$30.03	$113.26	$71.98
2033	$84.62	$73.58	$32.21	5%	100%	95%	$30.60	$115.22	$73.58
2034	$86.28	$75.15	$32.86	5%	100%	95%	$31.22	$117.50	$75.15
2035	$87.77	$76.77	$33.48	5%	100%	95%	$31.81	$119.58	$76.77

Notes:
A&B Based on Pacificorp compliance filing for Order 11-505 (UM 1396)
C Based on Pacificorp Advice 12-005, filed March 2, 2012
D&E Percentage of hours resources are available for contribution to peak, assumed in the utility's IRP

Explanation of Tables 1, 2 and 3 in Exhibit Staff/103

This Exhibit illustrates staff's proposed Renewable Avoided Cost calculation methods for a wind, solar and baseload QF. Staff used values from PacifiCorp's February 2012 compliance filing in UM 1396. However, these sample calculations are intended only to illustrate the methodology, not to represent any specific proposal.

Table 1 shows a sample renewable avoided price calculation for a hypothetical wind QF. The avoided resource is the renewable resource identified in the IRP (assumed to be wind in this example). Columns A and B show the avoided cost of the assumed wind resource. As in the Standard avoided cost price stream the avoided costs are assigned to on and off peak hours, and the on-peak price includes an implicit capacity contribution.

Column C is the value (to the utility) of capacity, taken directly from the Standard Oregon Method. Column D is the assumed capacity contribution to peak of the utility's *avoided* renewable resource (assumed to be 5% for wind, consistent with Exhibit 102). Column E is the capacity contribution of the wind QF, which we assigned the same value as the utility's avoided wind resource. Thus there is no *additional* capacity contribution from the QF relative to the avoided resource. The resulting on-peak and off-peak prices are the fixed costs of the utility's avoided wind resource, allocated to on and off peak periods. The results are in columns H and I.

Table 2 of the exhibit demonstrates the capacity adjustment for a hypothetical solar QF. Columns A through D are the same as Table 1. Column E shows an assumed capacity contribution for the hypothetical solar QF. (This example uses a 30% solar capacity contribution as a placeholder. The actual solar capacity contribution would come from the utility's IRP.)

In column F we subtract the avoided wind resource capacity contribution from that of the assumed solar capacity contribution. This is the incremental capacity contribution provided by the solar QF, relative to the capacity contributed by the *avoided* renewable resource.

We multiply this incremental contribution by the dollar value of capacity (column C) to arrive at the avoided capacity cost included in the on-peak price. The product, shown in column G, is a "capacity adder" and is included in the total on-peak price for the solar QF (Column H.)

Table 3 shows the same calculation for a baseload renewable QF. We assign the base load QF the same capacity contribution to peak load as an avoided baseload resource (we used 100% for illustration purposes). Its *incremental* capacity contribution, relative to the avoided renewable resource, is again shown in column F. In column G we multiply that incremental capacity contribution by its value to the utility (from column C) to arrive at a capacity adder. Columns H and I again show the resulting renewable avoided cost prices.

CERTIFICATE OF SERVICE

UM 1610

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 18th day of March, 2013 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
Telephone: (503) 378-5763

UM 1610
Service List

LOYD FERY **(W)**	11022 RAINWATER LANE SE AUMSVILLE OR 97325 dlchain@wvi.com
THOMAS H NELSON **(W)** ATTORNEY AT LAW	PO BOX 1211 WELCHES OR 97067-1211 nelson@thnelson.com
***OREGON DEPARTMENT OF ENERGY**	
MATT KRUMENAUER **(C) (W)** SENIOR POLICY ANALYST	625 MARION ST NE SALEM OR 97301 matt.krumenauer@state.or.us
ANNALA, CAREY, BAKER, ET AL., PC	
WILL K CAREY **(W)**	PO BOX 325 HOOD RIVER OR 97031 wcarey@hoodriverattorneys.com
ASSOCIATION OF OR COUNTIES	
MIKE MCARTHUR **(W)** EXECUTIVE DIRECTOR	PO BOX 12729 SALEM OR 97309 mmcarthur@aocweb.org
CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP	
RICHARD LORENZ **(C) (W)**	1001 SW FIFTH AVE - STE 2000 PORTLAND OR 97204-1136 rlorenz@cablehuston.com
CITIZENS' UTILITY BOARD OF OREGON	
OPUC DOCKETS **(W)**	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
ROBERT JENKS **(C) (W)**	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
G. CATRIONA MCCRACKEN **(C) (W)**	610 SW BROADWAY, STE 400 PORTLAND OR 97205 catriona@oregoncub.org
CITY OF PORTLAND - PLANNING & SUSTAINABILITY	
DAVID TOOZE **(W)**	1900 SW 4TH STE 7100 PORTLAND OR 97201 david.tooze@portlandoregon.gov
CLEANTECH LAW PARTNERS PC	
DIANE HENKELS **(C) (W)**	6228 SW HOOD PORTLAND OR 97239 dhenkels@cleantechlawpartners.com

COLUMBIA ENERGY PARTNERS LLC	
PETER P BLOOD **(W)**	317 COLUMBIA ST VANCOUVER WA 98660 pblood@columbiaenergypartners.com
DAVISON VAN CLEVE	
IRION A SANGER **(C) (W)**	333 SW TAYLOR - STE 400 PORTLAND OR 97204 ias@dvclaw.com
DAVISON VAN CLEVE PC	
MELINDA J DAVISON **(C) (W)**	333 SW TAYLOR - STE 400 PORTLAND OR 97204 mjd@dvclaw.com; mail@dvclaw.com
S BRADLEY VAN CLEVE **(C) (W)**	333 SW TAYLOR - STE 400 PORTLAND OR 97204 bvc@dvclaw.com
ENERGY TRUST OF OREGON	
ELAINE PRAUSE**(W)**	421 SW OAK ST #300 PORTLAND OR 97204-1817 elaine.prause@energytrust.org
JOHN M VOLKMAN **(W)**	421 SW OAK ST #300 PORTLAND OR 97204 john.volkman@energytrust.org
ESLER STEPHENS & BUCKLEY	
JOHN W STEPHENS **(C) (W)**	888 SW FIFTH AVE STE 700 PORTLAND OR 97204-2021 stephens@eslerstephens.com; mec@eslerstephens.com
EXELON BUSINESS SERVICES COMPANY, LLC	
PAUL D ACKERMAN **(C) (W)**	100 CONSTELLATION WAY STE 500C BALTIMORE MD 21202 paul.ackerman@constellation.com
EXELON WIND LLC	
JOHN HARVEY **(C) (W)**	4601 WESTOWN PARKWAY, STE 300 WEST DES MOINES IA 50266 john.harvey@exeloncorp.com
IDAHO POWER COMPANY	
REGULATORY DOCKETS **(W)**	PO BOX 70 BOISE ID 83707-0070 dockets@idahopower.com
DONOVAN E WALKER **(W)**	PO BOX 70 BOISE ID 83707-0070 dwalker@idahopower.com

LOVINGER KAUFMANN LLP	
KENNETH KAUFMANN **(C) (W)**	825 NE MULTNOMAH STE 925 PORTLAND OR 97232-2150 kaufmann@lklaw.com
JEFFREY S LOVINGER **(C) (W)**	825 NE MULTNOMAH STE 925 PORTLAND OR 97232-2150 lovinger@lklaw.com
MCDOWELL RACKNER & GIBSON PC	
ADAM LOWNEY **(W)**	419 SW 11TH AVE, STE 400 PORTLAND OR 97205 adam@mcd-law.com
LISA F RACKNER **(W)**	419 SW 11TH AVE., SUITE 400 PORTLAND OR 97205 dockets@mcd-law.com
NORTHWEST ENERGY SYSTEMS COMPANY LLC	
DAREN ANDERSON **(W)**	1800 NE 8TH ST., STE 320 BELLEVUE WA 98004-1600 da@thenescogroup.com
ONE ENERGY RENEWABLES	
BILL EDDIE **(C) (W)**	206 NE 28TH AVE PORTLAND OR 97232 bill@oneenergyrenewables.com
OREGON DEPARTMENT OF ENERGY	
KACIA BROCKMAN **(C) (W)**	625 MARION ST NE SALEM OR 97301 kacia.brockman@state.or.us
OREGON DEPARTMENT OF JUSTICE	
RENEE M FRANCE **(C) (W)**	NATURAL RESOURCES SECTION 1162 COURT ST NE SALEM OR 97301-4096 renee.m.france@doj.state.or.us
OREGON SOLAR ENERGY INDUSTRIES ASSOCIATION	
GLENN MONTGOMERY **(W)**	PO BOX 14927 PORTLAND OR 97293 glenn@oseia.org
OREGONIANS FOR RENEWABLE ENERGY POLICY	
KATHLEEN NEWMAN **(W)**	1553 NE GREENSWORD DR HILLSBORO OR 97214 kathleenoipl@frontier.com; k.a.newman@frontier.com

MARK PETE PENGILLY **(W)**	PO BOX 10221 PORTLAND OR 97296 mpengilly@gmail.com
PACIFIC POWER	
R. BRYCE DALLEY **(W)**	825 NE MULTNOMAH ST., STE 2000 PORTLAND OR 97232 bryce.dalley@pacificorp.com
MARY WIENCKE **(W)**	825 NE MULTNOMAH ST, STE 1800 PORTLAND OR 97232-2149 mary.wiencke@pacificorp.com
PACIFICORP, DBA PACIFIC POWER	
OREGON DOCKETS **(W)**	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
PORTLAND GENERAL ELECTRIC	
RANDY DAHLGREN **(C) (W)**	121 SW SALMON ST - 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
PORTLAND GENERAL ELECTRIC COMPANY	
J RICHARD GEORGE **(C) (W)**	121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 richard.george@pgn.com
PUBLIC UTILITY COMMISSION OF OREGON	
BRITTANY ANDRUS **(C) (W)**	PO BOX 2148 SALEM OR 97308-2148 brittany.andrus@state.or.us
ADAM BLESS **(C) (W)**	PO BOX 2148 SALEM OR 97308 adam.bless@state.or.us
PUC STAFF--DEPARTMENT OF JUSTICE	
STEPHANIE S ANDRUS **(C) (W)**	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
REGULATORY & COGENERATION SERVICES INC	
DONALD W SCHOENBECK **(C) (W)**	900 WASHINGTON ST STE 780 VANCOUVER WA 98660-3455 dws@r-c-s-inc.com
RENEWABLE ENERGY COALITION	
JOHN LOWE **(W)**	12050 SW TREMONT ST PORTLAND OR 97225-5430 jravenesanmarcos@yahoo.com

RENEWABLE NORTHWEST PROJECT	
RNP DOCKETS **(W)**	421 SW 6TH AVE., STE. 1125 PORTLAND OR 97204 dockets@rnp.org
MEGAN WALSETH DECKER **(C) (W)**	421 SW 6TH AVE #1125 PORTLAND OR 97204-1629 megan@rnp.org
RICHARDSON & O'LEARY	
GREGORY M. ADAMS **(C) (W)**	PO BOX 7218 BOISE ID 83702 greg@richardsonandoleary.com
RICHARDSON & O'LEARY PLLC	
PETER J RICHARDSON **(C) (W)**	PO BOX 7218 BOISE ID 83707 peter@richardsonandoleary.com
ROUSH HYDRO INC	
TONI ROUSH **(W)**	366 E WATER STAYTON OR 97383 tmroush@wvi.com
SMALL BUSINESS UTILITY ADVOCATES	
JAMES BIRKELUND **(C) (W)**	548 MARKET ST STE 11200 SAN FRANCISCO CA 94104 james@utilityadvocates.org
STOLL BERNE	
DAVID A LOKTING**(W)**	209 SW OAK STREET, SUITE 500 PORTLAND OR 97204 dlokting@stollberne.com