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May 22, 2015

***Via Electronic Filing***

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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SALEM OR 97308-1088

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

Enclosed for electronic filing is Public Utility Commission Staff's Opening Testimony.

/s/ Kay Barnes

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# PUBLIC UTILITY COMMISSION
# OF OREGON

## UM 1610
## Phase II

## STAFF OPENING TESTIMONY OF

## BRITTANY ANDRUS

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

**May 22, 2015**

CASE: UM 1610 PH II
WITNESS: BRITTANY ANDRUS

# PUBLIC UTILITY COMMISSION

# OF

# OREGON

# STAFF EXHIBIT 500

# Opening Testimony

# May 22, 2015

**Q. Please state your name, occupation, and business address.**

A. My name is Brittany Andrus. My business address is 3930 Fairview Industrial Dr. SE., Salem, Oregon 97302.

**Q. Please describe your educational background and work experience.**

A. My Witness Qualification Statement is found in Exhibit Staff/501.

**Q. What is the purpose of your testimony?**

A. I provide the Staff analysis and recommendations on the contested issues presented to the Commission in Phase II of this investigation into qualifying facility (QF) contracting and pricing. The issues listed below are those included in the March 26, 2015 Ruling in this docket establishing the Phase II issues list:

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 disputed 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?

**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. Please explain Issue No. 1 regarding ownership of renewable energy credits (RECs) during the last five years of a 20-year standard contract.**

A. The question presented is whether QFs selling power to utilities under the Standard Renewable Avoided Cost price stream must cede RECs to the utilities during periods of renewable resource deficiency that coincide with the last five years of a 20-year standard contract during which the QFs are compensated at market-based prices.

**Q. What is Staff's recommendation?**

A. As explained below, Staff believes the Commission's previous orders make clear that a QF must transfer RECs to utilities under the standard contract when compensated for them with deficiency-period Standard Renewable Avoided Cost prices.

**Q. Why do QFs receive market-based prices during the last five years of a 20-year standard contract even if the utility is resource deficient?**

A. In 2005, the Commission decided that QFs could ask for a standard contract with a term of up to 20 years.[1] The Commission concluded that it would authorize forecasted avoided cost prices for only the first 15 years of a 20-year contract, however, noting a "divergence between forecasted and actual avoided costs must be expected over a period of 20 years."[2] The Commission decided that "[g]iven our desire to calculate avoided costs as accurately as possible, and the testimony of several parties that avoided costs should not be fixed beyond 15 years, we are persuaded that standard contract prices should be fixed for only the first 15 years of the 20-year term. Tariffs and standard contract terms should provide that, in the event a QF opts for a standard contract with a 20-year term, the QF must take one of the market pricing options that we address later in this order for the final five years of the contract."[3]

**Q. Who asserts that QFs electing to receive Standard Renewable Avoided Cost prices must cede RECs to the utility while receiving market-based prices during the last five years of a 20-year standard contract if the utility is renewable resource deficient during that period?**

A. PacifiCorp notes that Order No. 11-505 provides that QFs selling at Standard Renewable Avoided Cost prices must cede RECs to the utilities during periods

[1] Order No. 05-584 at 19-20.
[2] Order No. 05-584 at 20.
[3] Order No. 05-584 at 20.

of resource deficiency and argues the order includes no exception to this requirement for the last five years of a 20-year standard contract when the QF receives market-based prices. Staff anticipates that PacifiCorp relies, at least in part, on the following language in Order No. 11-505 to support its position:

> During periods of renewable resource sufficiency, the rate will be based on market prices. During periods of renewable resource deficiency, the rate will be based on the renewable avoided cost of the next utility renewable resource acquisition in that utility's IRP. *The renewable resource QF will keep all associated Renewable Energy Certificates (RECs) during periods of renewable resource sufficiency, but will transfer those RECs to the purchasing utility during periods of renewable resource deficiency.*[4]

**Q. Does Staff agree with PacifiCorp's interpretation of Order No. 11-505?**

A. No. Staff believes that the Commission's requirement regarding REC transfer during renewable resource deficiency periods is based wholly on the fact that QFs are compensated for these RECs when they are paid deficiency-period prices based on the avoided fixed costs of the next avoidable renewable resource in the utility's Integrated Resource Plan (IRP). Staff believes that the Commission intended that QFs should retain the RECs when the QF is not compensated for the RECs with rates based on the avoided fixed costs of the next avoidable renewable resource.

**Q. Please explain the basis for Staff's assumption.**

In Order No. 11-505, the Commission determined that PGE and PacifiCorp should offer Standard Renewable Avoided Cost prices. Like Standard *Non-Renewable* Avoided Cost prices, these rates differ depending on whether the

[4] Order No. 11-505 at 1 (emphasis added).

utility is renewable resource sufficient or deficient.[5] During periods of renewable resource deficiency, the Standard Renewable Avoided Cost prices are based on the costs of the next avoidable renewable resource in the utility's IRP.[6] During periods of renewable resource sufficiency, the Standard Renewable Avoided Cost prices are based on the utility's forecasted monthly forward on- and off-peak prices.[7]

Under Order No. 11-505, QFs receiving Standard Renewable Avoided Cost prices keep the RECs associated with their generation when they receive market-based prices during periods of resource sufficiency and must cede the RECs to the utilities when receiving prices based on the utility's next avoidable renewable resource during the utility's renewable resource deficiency periods.[8]

**Q. Why do QFs cede their RECs when receiving Standard Renewable Avoided Cost prices that include the avoided fixed prices of the next avoidable resource in the utility's IRP?**

A. Because otherwise, the utility cannot avoid the cost to acquire a renewable resource. The Commission explained that "[r]enewable QFs willing to sell their output and cede their RECs to the utility allow the utility to avoid building (or buying) renewable generation to meet their RPS requirements.

[5] Order No. 11-505 at 1.
[6] Order No. 11-505 at 7.
[7] Order No. 11-505 at 9.
[8] Order No. 11-505 at 9.

These QFs should be offered an avoided cost stream that reflects the costs that the utility will avoid."[9]

**Q. Must renewable QFs always cede their RECs to the utility when the purchasing utility is renewable resource deficient?**

A. No. The Commission has ordered that renewable QFs must have the option to choose between the Standard Renewable Avoided Cost price stream and the Standard Non-renewable Avoided Cost price stream.[10] The Standard Renewable Avoided Cost prices are available to a QF only if the QF is willing to cede its RECs to the utility during the utility's deficiency periods.[11] Under the Standard Non-Renewable Avoided Cost price stream, QFs are not required to cede their RECs during periods of resource deficiency.[12]

**Q. Please summarize Staff's analysis regarding Issue No 1.**

A. A QF is required to transfer RECs to the utility under a standard contract when the QF is compensated for them with avoided cost prices based on the fixed costs of an avoidable renewable resource. If the rates during paid during a deficiency period do not include these avoided fixed costs because the deficiency period coincides with the last five years of a 20-year standard contract when the QF is paid market-based prices, then the QF is not required to transfer its RECs to the utility.

[9] Order No. 11-505 at 9. See also Order No. 11-505 at 7 ("If the QF does not transfer the renewable energy credits, the utility will not avoid costs to purchase energy that complies with the RPS.").
[10] Order No. 11-505 at 9.
[11] Order No. 11-505 at 7.
[12] Order No. 11-505 at 7.

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

**Q. Please explain this issue regarding inclusion of avoided transmission costs in the calculation of avoided cost prices.**

A. This issue is presented in Phase II at least in part to clarify the decision in Order No. 14-058 that PacifiCorp has no avoided third-party transmission costs because its proxy resource is on system:

> We affirm the existing policy that if the proxy resource used to calculate a utility's avoided costs is an off-system resource, the costs of the third-party transmission are avoided, and are therefore included in the calculation of avoided cost prices. This is the situation for PGE, and it was not contested in these proceedings.
>
> If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs, and thus the costs of third-party transmission are not included in the calculation of avoided costs prices. This is the situation for Pacific Power.[13]

After the Commission issued Order No. 14-058, OneEnergy, Inc., (OneEnergy) and the Community Renewable Energy Association (CREA) asked the Commission to clarify the Commission's decision regarding avoided third-party transmission costs for an on-system resource. The Commission denied the request, noting that OneEnergy and CREA "ask for more than clarification of Order No. 14-058 yet fail to demonstrate that reconsideration of the order is

[13] Order No. 14-058 at 17.

warranted, *as opposed to raising any additional or unanswered question(s) in Phase II of this docket*."[14]

**Q. Does Staff think it is appropriate for the Commission to provide additional guidance on inclusion of avoided transmission costs in the calculation of avoided cost prices for PacifiCorp?**

A. Yes. The Commission did not expressly address the assertions of some parties that PacifiCorp would have to build or otherwise acquire transmission to move energy from its proxy resource in transmission-constrained locations on its system.[15] Accordingly, some parties including Staff are unclear as to the meaning of the Commission's conclusion that PacifiCorp does not incur third-party transmission costs for proxy resources located on PacifiCorp's system. More specifically, it is not clear whether the Commission concluded that (1) no party demonstrated that PacifiCorp would avoid third-party transmission costs when the resource is on its system, and therefore inclusion of third-party transmission costs is not appropriate, or (2) even if PacifiCorp would avoid third-party transmission costs associated with an on-system proxy resource by purchasing QF energy, it is not appropriate to include such costs in the calculation of avoided cost prices when the proxy resource is an on-system resource.

[14] Order No. 14-229 at (Order denying reconsideration) (emphasis added).
[15] See UM 1610 Motion for Clarification and Application for Rehearing by OneEnergy and the Community Renewable Energy Association at 5 (citing evidence in support of assertion PacifiCorp must acquire transmission to move energy from proxy renewable resource in transmission-constrained location on PacifiCorp system.).

Further, it is not clear what the Commission concluded about the assertions that PacifiCorp may need to build new transmission resources to move energy from its proxy renewable resource in a transmission-constrained location and whether such costs could be included in the calculation of Standard Renewable Avoided Cost prices.

**Q. Why is it important to clarify the Commission's intent?**

A. Some of the parties believe that PacifiCorp would have to incur transmission costs for its next avoidable renewable resource indicated by its 2013 Integrated Resource Plan. PacifiCorp's 2013 IRP indicates that the next deferrable renewable resource is Wyoming wind.[16]

Q. **Is the Wyoming wind resource in question directly connected to PacifiCorp's system?**

A. Yes. However, because the amount of wind generation exceeds PacifiCorp's load in that area, this higher capacity factor wind energy would need to be transmitted to an area where PacifiCorp has sufficient load.[17] This raises the question of whether, if PacifiCorp had to use a third party to transmit energy from its proxy renewable resource or otherwise acquire a transmission resource, these avoided transmission costs should be included in PacifiCorp's Standard Renewable Avoided Cost prices.

[16] PacifiCorp 2013 Integrated Resource Plan, Table 8.7 – PacifiCorp's 2013 IRP Preferred Portfolio at 227.
[17] PacifiCorp 2013 Integrated Resource Plan, Table 6.10 – Cumulative Wind Selection Limits by Year and Energy Gateway Scenario.

**Q. What is the significance of parties' assertions regarding avoided transmission costs for the planned Wyoming wind farm to the issue presented here?**

A. Under Order No. 14-058, these costs could not be included in the calculation of PacifiCorp's avoided cost prices even if it could be shown that PacifiCorp would avoid them with a QF purchase.

**Q. Will PacifiCorp's purchase from a QF allow it to avoid third-party or other transmission costs for the avoided on-system proxy resource?**

A. Staff does not know. Whether PacifiCorp would avoid transmission costs, third-party or otherwise, for the currently avoidable proxy resource by purchasing power from a QF is a question that will be reviewed in connection with PacifiCorp's avoided cost filings. Staff does not think that this fact-specific question is presented in this docket.

**Q. Does Staff have a recommendation on the resolution of this issue?**

A. Yes. Staff recommends that the Commission clarify that neither avoided third-party transmission costs nor costs to build a transmission resource will be included in the calculation of avoided cost prices when they are not avoided whether the avoidable resource is on-system or off. Staff also recommends that the Commission clarify that such costs should be included in the calculation of avoided cost prices if the utility's IRP indicates the utility's purchase from the QF allows the utility to avoid them, or if this fact is established in the review process following the utility's avoided cost filing.

**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. Please explain how Issue 3 came to be included in the Phase II issues list.**

A. Parties addressed this issue on an expedited basis with testimony and briefs following the Commission's ruling allowing reconsideration of the capacity contribution calculation adopted by the Commission Order No. 14-058. The Commission has not yet resolved the issue. Instead, the Administrative Law Judges instructed the parties that additional discussion on this issue is appropriate and included the issue in the Phase II Issues List.

**Q. Please explain this issue.**

A. In Phase I of this investigation, Staff recommended that the Commission modify the methodology for calculating Standard Non-renewable and Renewable Avoided Cost prices offered during on-peak hours during resource deficiency periods so that the prices reflect the inherently different contributions to peak (CTP) load of different QF resource types.[18] The Commission adopted Staff's recommended adjustments.[19]

Subsequently, Obsidian Renewables, LLC (Obsidian) asked the Commission to reconsider its order adopting the Staff capacity contribution adjustment for

[18] Staff/100 and/200.
[19] Order No. 14-058 at

Solar Renewable Avoided Cost prices, noting that the methodology proposed by Staff resulted in two discounts to the capacity payments to solar QFs, one based on the QF's on-peak capacity factor and the other (the one adopted in Order No. 14-058) on the QF's CTP.[20] Staff supported the request for reconsideration, agreeing with Obsidian that the Staff proposed methodology resulted in an unintended *double* discount when applied to solar QFs. Staff asked the Commission to schedule additional proceedings on whether the calculation should be modified. The Commission granted Staff's request for additional proceedings.

**Q. You note that the method adopted by the Commission in Order No. 14-058 imposes two discounts on capacity payments to intermittent QFs, one based on the resource's "on-peak capacity factor" and another based on the resource's "contribution to peak (CTP)." What are a resource's "on-peak capacity factor" and "contribution to peak"?**

A. A capacity factor is the ratio of the energy produced over a period of time (MWh) to the total that could be generated at maximum capacity (MW) over that same period:

Capacity Factor = Energy / (Capacity x hours)

For annual capacity factors, the time period is one year, or 8760 hours (8,784 hours in a leap year). An on-peak[21] capacity factor is the same ratio, but

[20] Obsidian, LLC's April 24, 2014 Motion for Clarification at 2.
[21] On-peak hours are defined by the National Energy Reliability Corporation (NERC) as 6:00 a.m. to 10.p.m Monday through Saturday, excluding specified holidays.

over only the on-peak hours. On-peak hours are 56 to 57 percent of the hours in a year. Please see the following example for 2015.

| | Hours in 2015 | | |
|---|---|---|---|
| | Total | On-Peak | Off-Peak |
| Jan | 744 | 416 | 328 |
| Feb | 672 | 384 | 288 |
| Mar | 743 | 416 | 327 |
| Apr | 720 | 416 | 304 |
| May | 744 | 400 | 344 |
| Jun | 720 | 416 | 304 |
| Jul | 744 | 416 | 328 |
| Aug | 744 | 416 | 328 |
| Sep | 720 | 400 | 320 |
| Oct | 744 | 432 | 312 |
| Nov | 721 | 384 | 337 |
| Dec | 744 | 416 | 328 |
| Total | 8,760 | 4,912 | |
| | | 56.1% | |

So, the on-peak capacity factor is the same calculation using the number of on-peak hours, as follows:

On-peak Capacity Factor = On-peak Energy / (Capacity x On-peak hours)

The CTP is the percentage of a resource's capacity expected to be generating during a utility's peak load.[22] There are different methods for calculating a resource's CTP. How to calculate a resource's CTP is not at issue in this investigation. The only question is how to account for a resource's CTP when calculating avoided cost prices.

[22] Staff/300, Andrus/5.

**Q. What positions did parties take in the supplemental proceedings?**

A. Staff, CREA, the Renewable Energy Coalition (REC), the Oregon Department of Energy (ODOE), Renewable Northwest (RNW), Obsidian, and One Energy, testified that the adjustment methodology adopted by the Commission had the unintended effect of applying two decrementing adjustments to the capacity payments received by solar QFs during deficiency periods. These parties explained, in various ways, that the Staff-proposed method layered the new adjustment for the solar QFs' CTP on top of the on-peak capacity factor "adjustment" already embedded in the avoided cost methodology. Portland General Electric Company (PGE), PacifiCorp, and Idaho Power Company (Idaho Power) testified that the method adopted by the Commission did precisely what was intended, which was to lower payments for avoided capacity costs to account for different CTPs of different QF resource types.

**Q. Are the utilities correct that the Commission merely intended to decrease capacity payments to QFs?**

A. Staff does not think so. In the introductory portion of Order No. 14-058, the Commission indicated that it adopted the adjustment to avoided cost prices (proposed by Staff) to take into account the different contribution to peak load that different QF resource types provide:

> We modify the current methodology for calculating standard avoided cost prices and standard renewable avoided cost prices to account for the capacity contribution of different QF resources[.][23]

[23] Order No. 14-058 at 2.

This language indicates the Commission adopted the Staff's rationale for the calculation adjustment, which was to better match the deficiency-period capacity payments to QFs with the QFs CTP, based on QF resource type.

**Q. Why is the Commission's intent in Phase I important to the question of whether the calculation should be modified?**

A. If the Commission's intent in adopting the adjustment proposed by Staff was simply to significantly reduce capacity payments to solar QFs, rather than to make these payments commensurate with each QF resource type's CTP, then the utilities are correct that no change to the methodology adopted by the Commission in Order No. 14-058 is needed.

However, if the Commission adopted Staff's proposed adjustment for the purpose of better matching avoided capacity cost payments to QFs with their CTP, then it is necessary to modify the methodology proposed by Staff in Phase I.

**Q. How do you know the Order No. 14-058 methodology results in capacity payments to solar QFs during on-peak hours during the utility's deficiency period that are not correlated to the value of the solar QFs' CTP?**

A. Staff's testimony submitted after the Commission granted reconsideration of Order No. 14-058 includes examples of the amounts a solar QF resource could expect to be paid for capacity over a one-year period under the avoided cost price method used prior to the adoption of Standard Renewable Avoided Cost Prices in Order No. 11-505 ("Previous Method"), the method adopted in

Order No. 14-058 ("Current Method"), and the revised method Staff proposed after the Commission granted reconsideration ("Proposed Method").[24]

Under the Previous Method, a solar QF could expect to receive a percentage of the utility's total avoidable capacity costs roughly equal to that QF's on-peak capacity factor. The example shows that an individual QF resource with an on-peak capacity factor of 27.5 percent, could expect annual capacity payments equal to approximately 30 percent of the utility's avoided capacity costs used for the avoided cost calculation.[25]

Under the Current Method, the same solar QF could expect to receive less than three percent of the utility's annual avoided costs for capacity.[26] Finally, under the Proposed Method, the same solar QF could expect to receive annual payments for avoided capacity roughly equal to the solar resource's CTP of 13.6 percent.[27]

**Q. Please explain why the method adopted in Order No. 14-058 results in a "double discount."**

A. QFs in Oregon receive payments for capacity during the period in which the utility is resource deficient, which begins in the year the utility's IRP shows the first deferrable resource, whether standard or renewable. The value of capacity has historically been calculated based on the fixed costs of a single-cycle combustion turbine (SCCT), on a dollar-per-kW-per-year basis.

[24] Staff/400, Andrus/5.
[25] Staff/400, Andrus/5.
[26] Staff/400, Andrus/5.
[27] Staff/400, Andrus/5.

This method establishes the value per kW for avoided capacity on a generic basis, for all resources, whether renewable or non-renewable.

Intermittent QFs did not receive capacity payments over the course of the year equal to the utility's annual avoided costs for capacity per unit under the Previous Method, however. This is because the rate used to pay the avoided capacity costs spread the total annual avoided costs per unit equally to every on-peak hour of the year. An intermittent resource that could not operate in each on-peak hour could therefore expect to receive a percentage of the total annual avoided capacity costs roughly equal to the percentage of its ratio of on-peak generation to capacity. In other words, the QF could expect to receive a percentage of the utility's total annual avoided costs for capacity roughly equal to the QF's on-peak capacity factor.

The Current Method for calculating the capacity contribution adjustment of different resources adopted in Phase I, adjusts the rate for capacity, which is expressed as dollars per MWh applying a ratio to account for the different CTP of intermittent QFs. However, the traditional dollars-per-kWh capacity payment rate is based on the availability of a baseload resource during on-peak hours. Accordingly, using this traditional rate as the starting point for a capacity-contribution adjustment means that any resource that does not operate as a baseload resource will not receive payments reflective of the QF's capacity contribution, but will receive only a fraction of such payments.

**Q. How does Staff propose to correct this shortfall in the capacity payments to QFs?**

A. Staff proposes to adjust the avoided value of capacity to derive a value for the solar capacity on a dollar-per-unit basis (kW or MW of capacity) prior to calculating the on-peak payment rate.

**Q. Please provide an example calculation for the value of solar capacity.**

A. First, adjust the CTP of the proxy renewable resource to account for the CTP of solar resources relative to the renewable avoided resource, which is wind. Then, apply that differential to the value of capacity:

(CTP of solar minus CTP of wind) x value of capacity = value of solar capacity

(39% - 5%) x $104/kW-year = $35.36/kW-year solar capacity value, or $35,360/MW-year

**Q. How would the on-peak MWh payment for capacity be calculated?**

A. The value of the solar capacity is spread over the expected on-peak generation by applying the on-peak capacity factor for solar to the total number of on-peak hours per year:

> Value of solar capacity per MW per year/(solar on-peak capacity factor x on-peak hours/year)
>
> $40,560/MW-year / (37.4% x 4,912) = $22.08 per On-peak MWh

**Q. Please provide a graphical representation of CTP and on-peak capacity factors.**

A. Figure 1 below portrays a one-day view of a utility system load, a CCCT, and a solar resource, with the on-peak hours bounded by the dotted lines. Figure 1 is also included as Exhibit 502.

The CTP and the on-peak capacity factor for the CCCT and the solar resource are calculated as follows:

**<u>CTP</u>:**

<u>300 MW CCCT</u>

Generation at hour of peak / Capacity = CTP

300 MW / 300 MW = 100 percent CTP

<u>100 MW Solar QF</u>:

Generation at hour of peak / Capacity = CTP

39 MW / 100 MW = 39.0 percent CTP

**<u>On-peak Capacity Factor:</u>**

<u>300 MW CCCT</u>:

On-peak MWh / (On-peak hours * Capacity) = On-peak capacity factor

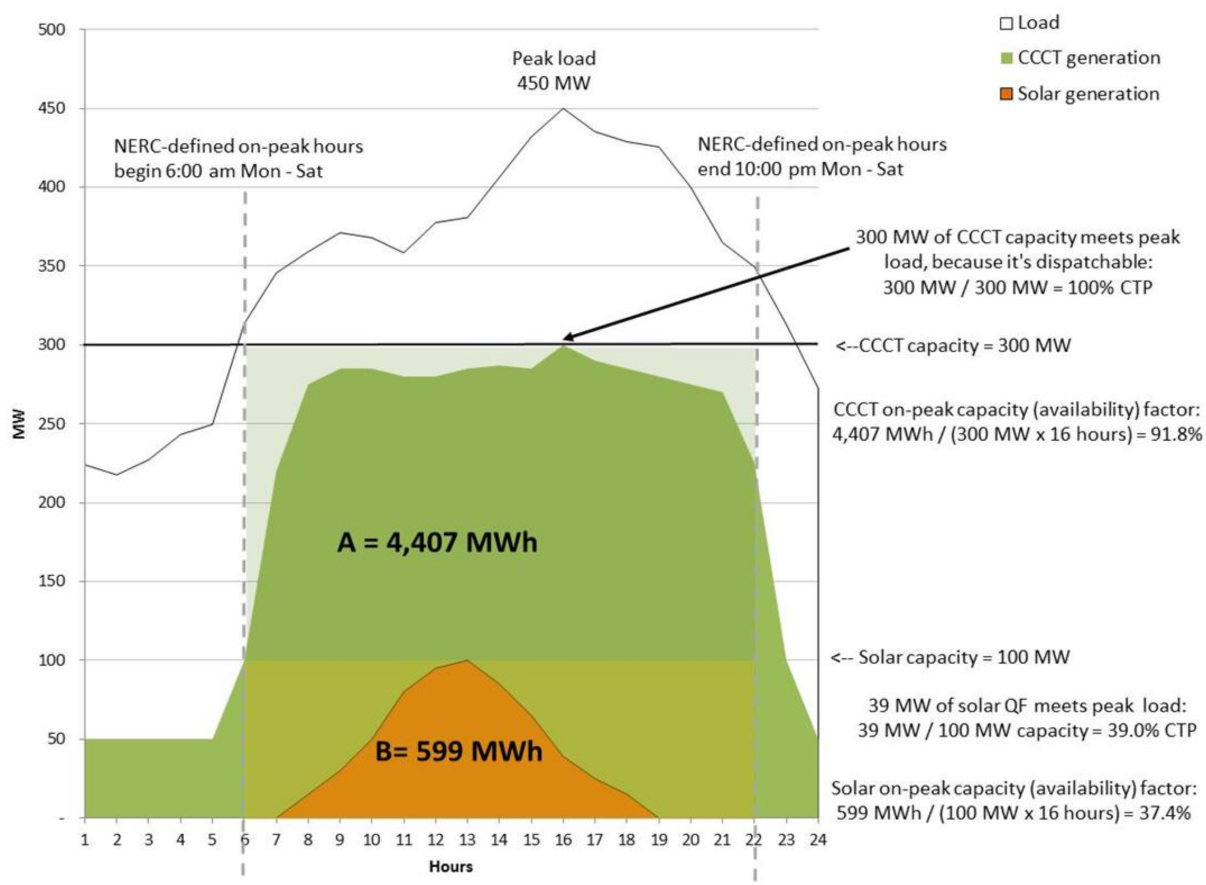
4,405 MWh / (16 hours * 300 MW) = 91.8 percent On-peak capacity factor

<u>100 MW Solar QF</u>:

On-peak MWh / (On-peak hours * Capacity) = On-peak capacity factor

599 MWh / (16 hours * 100 MW) = 37.4 percent On-peak capacity factor

Figure 1.




**Q. How does this graphic illustrate the problem with the Current Method?**

A. The ratio of CCCT MWh generation over on-peak hours to the maximum that could be generated is significantly larger than that same ratio for the solar resource. Once the amount of dollars for the relative capacity contributions are spread over the number of on-peak MWh generated, an accurate on-peak energy rate is calculated that will provide each resource the correct annual compensation for its capacity.

**Issue 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?**

**Q. What is Staff's position on this issue?**

A. Staff believes that the Commission should also revise the methodology for calculating the capacity contribution adjustment under Standard Non-Renewable Avoided Cost prices so that the annual amounts for avoided capacity costs paid to intermittent resources are commensurate with the intermittent resource's CTP. An adjustment to the payment methodology must be made for any resource that does not have an on-peak capacity factor equivalent to that assumed for a thermal resource (CCCT).

Q. How would the method for solar QFs described above in Issue 3 be applied to other QFs such as wind, solar and baseload?

A. In each case, an estimate of the on-peak availability factor will need to be calculated and applied. The CTP would continue to come from the IRPs, as would the value of capacity based on the SCCT costs. The formula would be as follows:

(Value of capacity x CTP x QF Capacity) /

On-peak availability factor x On-peak hours

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

**Q. Please explain this issue.**

A. Parties to UM 1610 disagree on the appropriate venue to challenge inputs in the utilities' avoided cost filings, particularly avoided cost filings submitted within 30 days of acknowledgment of the utilities' IRPs.

**Q. Does Staff believe that the Commission has resolved this issue in prior orders?**

A. Yes. In Order No. 05-584, the Commission stated,

> [a]voided cost filings are subject to suspension and the same investigatory process that any tariff filing may undergo. Natural gas forecasts that utilities use in avoided cost filings are, therefore, also subject to investigation and full review. We encourage ODOE and other interested parties to seek suspension of an avoided cost filing when necessary to address concerns about natural gas forecasts, or any other aspect of a utility's filing.[28]

The Commission echoed this statement in Order No. 06-538, which was a Commission order determining whether utilities' avoided cost filings were compliant with Order No. 05-584:

> We reminded parties [in Order No. 05-584], however, that a utility's natural gas forecasts could be examined and challenged during review of the utility's avoided cost filing. Indeed, we encouraged parties to seek suspension of an avoided cost filing when necessary to address concerns about natural gas forecasts or any other aspect of a utility's filing. We also observed that Staff, or any other party, could introduce, during a future investigation of a utility's avoided costs filing, an independent natural gas forecast for comparison purposes.[29]

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[28] Order No. 05-584 at 36-37.
[29] Order No. 06-538 at 44.

The Commission’s current administrative rules are consistent with its observations that avoided cost filings are subject to suspension and review processes like tariffs for sale of electricity. OAR 860-029-0040(4)(a) provides:

> (4) Standard rates for purchases shall be implemented as follows:
>
> (a) In the same manner as rates are published for electricity sales each public utility shall file with the Commission, within 30 days of Commission acknowledgement of its least-cost plan pursuant to Order No. 89-507, standard rates for purchases from qualifying facilities with a nameplate capacity of one megawatt or less, to become effective 30 days after filing. The publication shall contain all the terms and conditions of the purchase. Except when a public utility fails to make a good faith effort to comply with the request of a qualifying facility to wheel, the public utility's standard rate shall apply to purchases from qualifying facilities with a nameplate capacity of one megawatt or less.

And, OAR 860-029-0080 provides, in pertinent part:

> (3) Each public utility shall file with the Commission draft avoided-cost information with its least-cost plan pursuant to Order No. 89-507 and file final avoided-cost information within 30 days of Commission acknowledgment of the least-cost plan to be effective 30 days after filing.
>
> * * * * *
>
> (6) State review: Any data submitted by a public utility under this rule shall be subject to review and approval by the Commission. In any such review, the public utility has the burden of supporting and justifying its data. *Any standard rates filed under OAR 860-029-0040 shall be subject to suspension and modification by the Commission.*[30]

**Q. Given these statements in Order Nos. 05-584 and 06-358, why is there disagreement on the appropriate forum to litigate issues related to the utilities’ avoided cost filings?**

[30] Emphasis added.

A. In orders issued in 2010 and 2011, the Commission determined that the utilities' IRP processes are the appropriate venue to determine the utilities' resource positions used to establish the avoided cost rates:

> [T]he IRP process is the appropriate venue for addressing resource sufficiency/deficiency issues because the IRP processes are conducted with extensive public review regarding the timing of the utility's loads and its consequent resource needs. [31]

The Commission subsequently concluded that a utility's renewable resource position would also be determined in its IRP, concluding,

> [w]e earlier found the IRP process to be the appropriate venue for determining when a utility is resource sufficient or deficient. The derivation of a renewable avoided cost fits well within the same framework and allows issues relating to resource sufficiency or deficiency to be addressed as part of an integrated whole.[32]

**Q. Are the Commission's orders regarding stakeholders' opportunity to challenge every aspect of avoided cost filings in the process that follows the filings inconsistent with the Commission's orders that the determination of the utilities' resource sufficiency/deficiency positions will be made during review of the utilities' IRPs?**

A. Staff does not know if the orders are inconsistent, but believes that when they are read together, it is not clear whether Staff or parties to the review process following a utility's avoided cost filing can challenge a utility's determinations of its resource sufficiency/deficiency positions taken from the utility's IRP.

[31] Order No. 10-488 at 8.
[32] Order No. 11-505 at 6.

**Q. What does Staff recommend?**

A. Staff recommends that the Commission clarify that the utility's determinations of resource sufficiency/deficiency periods in its IRP are subject to challenge in the review of the utility's avoided cost filing in the same manner "as any other aspect of a utility's filing."[33] Otherwise, singling out the determination of resource sufficiency/deficiency from all the other assumptions that are subject to investigation in the review of avoided cost filings could obtain illogical results. For example, Order Nos. 05-584 and 06-538 make clear that parties may challenge the utility's gas price forecasts.[34] Substituting a different gas price forecast for that used by a utility in its avoided cost filing could change the date indicated for a new resource. However, if parties to the avoided cost review process could not challenge the resource sufficiency/deficiency demarcation in the utility's avoided cost filing, avoided cost rates would nonetheless be set on a resource sufficiency/deficiency determination that is no longer consistent with other inputs in the utility's avoided cost filing.

**Q. Will Staff's proposal result in more litigation following the utilities' avoided cost filings?**

A. Staff does not think so. The recommendation above is not a significant change to the process already used by the Commission. Staff is merely recommending that the Commission clarify that the demarcation of renewable

[33] See Order No. 05-584 at 36-37 ("We encourage ODOE and other interested parties to seek suspension of an avoided cost filing when necessary to address concerns about natural gas forecasts, or any other aspect of a utility's filing.").
[34] See Order No. 05-584 at 36-37 and Order No. 06-538 at 44.

resource sufficiency and deficiency is like other inputs into the utilities' avoided cost prices, should not be singled out and subject to different procedural requirements.

Furthermore, the core question in the avoided cost review process remains the same—what are the utility's avoided costs? This question is specific to each utility. A stakeholder may show that the utility could reasonably have made other resource decisions and would therefore avoid different costs, but this showing does not alter the fact that the costs indicated by the utility's Action Plan are the costs the utility will avoid.

**Q. Does Staff think it is appropriate to make any change to the process used to review utility avoided cost filings?**

A. Yes. Staff recommends that the Commission require utilities to satisfy minimum filing requirements "MFRs" when they make avoided cost filings. Currently, it can be difficult to discern from each utility's avoided cost filing what inputs the utility used to calculate avoided cost prices. It generally takes a few rounds of discovery before Staff can ascertain the basis for the utility's calculation of avoided costs. The need for discovery to determine the basis of the utility's avoided cost calculations can trigger a Staff request to suspend the utilities' avoided cost filing to allow opportunity to investigate.

Staff believes that requiring utilities to file certain information with their avoided cost filings may significantly decrease the need for discovery and hasten implementation of updated avoided cost rates.

**Q. What filing requirements does Staff recommend?**

A. Staff includes a list detailing the MFRs at Exhibit 503. The MFRs require the utilities to identify information such as the year demarcating between resource sufficiency and deficiency periods, the location and nameplate capacity of the utility's proxy resource, and the source of the utility's gas price forecast.[35] Below is an excerpt of Exhibit 502 to provide an example of a few of the proposed MFRs:

| | |
|---|---|
| **1.** | Non-renewable: Identify the demarcation year for the end of sufficiency period/start of deficiency period |
| **2.** | Non-renewable: Identify the major resource to be acquired (>100 MW and longer than 5 years) at end of sufficiency period |
| **3.** | Renewable: Identify the demarcation year for the end of sufficiency period/start of deficiency period |
| **4.** | Renewable: Identify the major resource to be acquired (>100 MW and longer than 5 years) at end of sufficiency period |

**Q. Isn't this information already included in the utilities' avoided cost filings?**

A. It is very likely all this information may be found in the utility's IRP and possibly in workpapers that may accompany the utility's avoided cost filing. The point is, however, that it is often difficult to find this information without asking for it directly with Data Requests. This necessity for discovery often means that avoided cost prices become effective only after Staff and stakeholders have had opportunity to conduct discovery to understand the basis of the utility's avoided cost calculations. Staff thinks that requiring the utilities to be explicit

[35] Staff Exhibit 503 (Staff Proposed Minimum Filing Requirements).

regarding the inputs used to calculate avoided cost prices will facilitate the review of the avoided cost prices and will likely reduce the need for extended processes to review the utilities' filings.

**Q. Is there a limit on the duration of any review process following a utility's avoided cost filing?**

A. No. OAR 860-029-0040(4)(a) specifies that the avoided cost filings should include prices to be effective 30 days after the filing, but OAR 860-029-0080(6) and Order Nos. 05-584 and 06-358 make clear that these prices are subject to "suspension and investigation" like utility tariffs.[36] There is no statutory or other deadline on how long the Commission has to review the avoided cost filings. Nonetheless, Staff recommends the Commission require the MFRs to help ensure review of avoided cost filing is as efficient and speedy as possible.

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

**Q. Please explain the questions presented under the issue related to compensation for capacity.**

A. Some parties believe the Commission's calculation of avoided cost prices during a utility's "sufficiency period" violates the Public Utility Regulatory Policy Act (PURPA) because QFs are not sufficiently compensated for capacity during these periods. Second, some parties believe the Commission's method for demarcation of resource sufficiency and deficiency periods is inappropriate

[36] See Order No. 05-584 at 26-27; Order No. 06-538 at 44.

because it results in resource sufficiency period designations even when the utility is acquiring a significant amount of additional capacity.

**Q. Does Staff believe that the Commission's avoided cost prices during sufficiency periods violate PURPA?**

A. No. The Commission differentiates rates for resource sufficiency and deficiency periods because "a utility's avoided costs differ depending on the resource position of the utility."[37] When the utility is resource deficient, the calculation of avoided costs has included both the variable and fixed costs of a planned resource in order to reflect the actual deferral or avoidance of that resource."[38] During periods of resource sufficiency, the utility does not avoid the acquisition of a resource, and therefore the fixed costs of an avoidable resource are not included in the calculation.[39]

Prior to 2005, the Commission traditionally based sufficiency period avoided cost prices on the variable costs of operating existing generating resources.[40] Staff and other parties challenged this calculation in Docket No. UM 1182 because it included no capacity payment.[41]

In Order No. 05-584, the Commission determined that it would use a "market-based valuation methodology" to compensate QFs for capacity during periods of resource sufficiency.[42] Specifically, the Commission "adopt[ed] the

[37] Order No. 05-584 at 26.
[38] Order No. 05-584 at 26.
[39] Order No. 05-584 at 26.
[40] Order No. 05-584 at 21-22. (PGE abandoned this method in 2001 and began using market-based prices to calculate resource sufficiency and deficiency period prices. This fact is not relevant to the issue presented here, however.)
[41] Order No. 05-584 at 27.
[42] Order No. 05-584 at 28.

methodology that values avoided costs when a utility is in a resource sufficient position at the monthly on- and off-peak forward market prices as of the utility's avoided cost filing."[43] The Commission concluded that this method "embeds the value of incremental QF capacity in the total market-based avoided cost rate."[44]

Notably, the Commission determined that using monthly forward on- and off-peak prices sufficiently compensates QFs for capacity during sufficiency periods even when the utilities ramp up market purchases while waiting for demand to warrant acquisition of a major resource:

> 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 a new utility plant to be illustrative.[45]

**Q. Does Staff believe the Commission's current methodology adequately compensates QFs for capacity during the utilities' sufficiency periods?**

A. Yes. Staff believes the relationship between the utilities' capacity needs during sufficiency periods and the prices for capacity paid to the QFs is sufficient to comply with PURPA.

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[43] Order No. 05-584 at 28.
[44] Order No. 05-584 at 28.
[45] Order No. 05-584 at 28.

**Q. What is the concern regarding the demarcation of resource sufficiency and deficiency periods that you mentioned earlier?**

A. Some parties believe the Commission's determination that a resource deficiency period begins with the planned acquisition of a "major resource" that is of at least five years in duration and at least 100 MW results in inappropriately long resource sufficiency periods.

**Q. Please provide some background for this issue.**

A. In Order No. 10-488, the Commission determined that for both two-year and post-IRP avoided cost filings, "the start date of the first major resource in the action plan of the most recent acknowledged IRP demarcates the resource sufficiency and deficiency periods."[46] The Commission used the definition of "major resource" that is used in the Commission's competitive bidding rules, which is a resource that is at least five years in duration and at least 100 MW.[47]

**Q. Does Staff believe that it is appropriate to use some other benchmark to demarcate the beginning of a resource deficiency period?**

A. Currently, Staff believes the Commission's determination that a deficiency period commences with the start date of the utility's next planned resource of at least 100 MW and five years of duration should not be modified.

[46] Order No. 10-488 at 3 (internal quotations omitted).
[47] Order No. 10-488 at 3; Order No. 06-466 at 3-4(defining "major resource" for purpose of Commission's Competitive Bidding Guidelines for new resources).

**Issue 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?**

**Q. What methodology for calculating non-standard avoided cost prices is currently in place in Oregon?**

A. Order No. 07-360 established guidelines for negotiated, non-standard contracts between utilities and large QFs. Large QFs are those greater than 10 MW nameplate capacity.

The following utility-specific guidance was provided in Order No. 07-360:

- For PGE and PacifiCorp, the yearly avoided costs approved for the 20-year period for standard contracts should serve as the starting point for negotiations. The prices may be modified to address specific enumerated factors approved by the Oregon Commission. The utility will provide to the QF a description of the methodology for each adjustment to standard avoided costs and how each adjustment was made.[48]
- For Idaho Power, the starting point for negotiations are the avoided costs calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages.[49]

**Q. Are PGE and PacifiCorp required to use Standard Renewable Avoided Cost prices as the starting point when the QF seeking a non-standard contract is a renewable QF?**

[48] Order No. 07-360, Appendix A, "Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs 10 MW or Larger."
[49] Order No. 07-360, Appendix A, "Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs 10 MW or Larger."

A. Staff does not think so. The Commission issued its guidelines for negotiating non-standard contracts prior to their decision to require PGE and PacifiCorp to offer Standard Renewable Avoided Cost prices. The Commission's order requiring Standard Renewable Avoided Cost prices does not specify that PacifiCorp and PGE are to use these renewable prices as the starting point for negotiations with renewable QFs seeking non-standard contracts. In the absence of such a requirement, Staff interprets Order No. 07-360 to require that Standard Non-Renewable Avoided Cost prices are the starting point for negotiations regardless of whether the negotiating QF is a renewable or non-resource.

**Q. How many QFs larger than 10 MW are currently operating in Oregon?**

A. Three.

**Q. What alternatives are available to the adjustment method currently employed by PGE and PacifiCorp?**

A. In Phase I of this docket, PacifiCorp proposed to calculate avoided cost prices for non-standard QFs using a method based on its production cost model ("Generation and Regulation Initiative Decision Tools, or GRID).[50] This method, known as the Partial Displacement Differential Revenue Requirement, entails running GRID two times: once using the preferred portfolio from the IRP, and a second time including the operating characteristics of the proposed

[50] UM 1610 Phase I PAC/100, Dickman/7.

QF with energy at zero cost, and with the capacity of the next deferrable resource reduced proportionately to the proposed QF's capacity contribution.[51]

**Q. What is Staff's view of the benefits and drawbacks of using a model-based approach for pricing large QFs relative to the approach that makes adjustments to the standard QF avoided cost prices?**

A. The Standard Non-Renewable Avoided Cost prices during the deficiency period are based on the fixed and variable costs of a combined cycle combustion turbine (CCCT), split into its energy and capacity components. It is a generic calculation that does not take into account the specific operations of a utility's system. This method is appropriate for QFs under the 10 MW standard eligibility cap because in that it provides transparency in exchange for its lack of precision. The complexity of the modeling approach for larger QFs is justified, as it is likely to provide a more accurate quantification of the impact of a QF based on its specific characteristics than a generic CCCT calculation with adjustments applied to it. To put it simply, an estimate (the adjustments) overlaid onto a simplified estimate (the avoided CCCT resource) will likely be less accurate than a single complex estimate.

**Q. What is the basis for Staff's support of the use of hourly economic dispatch models?**

The power cost models currently used by the three electric utilities have been proven to be reasonable tools for estimating power costs. These models have been used and reviewed in detail in power cost cases for many years.

[51] UM 1610 Phase I, PAC/100, DIckman/7-10.

Staff believes the models reasonably represent each utility's dispatch operation, and therefore, provide a useful method for estimating non-standard avoided costs prices for large QFs.

**Q. Does PGE ask to use a model-based approach to calculating non-standard avoided cost prices?**

A. PGE did not ask to do so in Phase I, but indicated it preferred to use the current Commission-approved method. Staff thinks it is reasonable to allow PGE to continue to do so even if the Commission authorizes another method for PacifiCorp and Idaho Power.

**Q. What method does Idaho Power currently use to negotiate non-standard avoided cost prices?**

A. As noted above, Idaho Power is allowed to use the modeling methodology authorized by the Idaho Public Utilities Commission, with some additional requirements imposed by this Commission, as the starting point for negotiations with QFs seeking non-standard rates.[52] In Phase I of this proceeding, Idaho Power asked for some modifications to this methodology.[53]

**Q. What is Staff's position on Idaho Power's proposal?**

A. Staff does not know whether Idaho Power continues to propose the same changes to its method for negotiating non-standard rates. Staff will address any Idaho Power proposal in its next round of testimony.

[52] Order No. 07-360, Appendix A, "Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs 10 MW or Larger."
[53] Phase I UM 1610 Idaho Power/200, Stokes/29-32.

**Issue 8: When is there a legally enforceable obligation?**

**Q. What is a legally enforceable obligation?**

A. Under PURPA, a QF can sell its generation to a utility "as available" or "pursuant to a legally enforceable obligation."[54] For sales pursuant to a legally enforceable obligation (LEO) the QF can choose to have prices based on avoided costs calculated at the time of the LEO or at the time the QF commences delivery to the utility.[55] In most transactions between QFs and utilities, the LEO arises when both the QF and the utility execute a power purchase agreement (PPA). However, as explained below, limiting the creation of a LEO to an executed agreement likely conflicts with PURPA and with Oregon's statutes implementing PURPA.

**Q. What issue regarding LEOs is presented to the Commission?**

A. In what circumstances (other than an executed PPA) does a LEO arise?

**Q. Please provide some background information to provide context for the Commission's decision on this issue.**

A. In a 2011 declaratory ruling regarding the Idaho Public Utilities Commission's policy regarding LEOs, FERC explained the purpose of a LEO,

> Section 292.304(d) and the requirement that a QF can sell and a utility must purchase pursuant to a legally enforceable obligation were specifically adopted to prevent utilities from circumventing the requirement of PURPA that utilities purchase energy and capacity from QFs. The Commission explained [in Order No. 69 adopting rules to implement PURPA]:
>
> > Paragraph (d)(2) permits a qualifying facility to enter into a contract or other enforceable obligation to

[54] 18 C.F.R. §292.304(d).
[55] 18 C.F.R. §292.304(d).

> provide energy or capacity over a specified term. *Use of the term "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible facility merely by refusing to enter into a contract with a qualifying facility*.[56]

> Thus, under our regulations, a QF has the option to commit itself to sell all or a part of its electric output to an electric utility. While this may be done through a contract, if the electric utility refuses to sign a contract, the QF may seek state regulatory assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA.[57] Accordingly, a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.[58]

In 1987, the Oregon Court of Appeals reached a similar conclusion regarding the creation of a LEO, and interpreted PURPA and its implementing regulations much as FERC did in FERC's 2011 ruling excerpted above. In *Snow Mountain Pine v. Maudlin,* the court noted that the utility's obligation to purchase from the QF,

> is not governed by common law concepts of contract law; it is created by statutes, regulations and administrative rules. ORS 758.525 requires a utility to purchase power from a qualifying facility. Similarly, 18 C.F.R. §292.303(a) and OAR 860-020-0030 provide that an electric utility "shall purchase" any energy and capacity "which is made available from a QF." Thus, the obligation to purchase power is imposed by law on a utility; it is not voluntarily assumed.[59]

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[56] *Cedar Creek Wind, LLC,* 137 FERC 61006 (2011 WL 4710848), *quoting* Order No. 69, FERC Stats. & Regs. 30,128 at 30,889 (emphasis added).
[57] *Id., citing New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, FERC Stats. & Regs. Par. 31,233 at p 212 (2006), *order on reh'g,* Order No. 688-A, FERC Stats. & Regs. 31,250, at p 136-37 (2007), *aff'd sub nom. American Forest and Paper Association v. FERC,* 550 F.3d 1179 (D.C. Cir. 2008), *see also Midwest Renewable Energy Projects, LLC,* 116 FERC 61,017 (2006).
[58] *Id., citing JD Wind 1,* 129 FERC 61,148 at p 25.
[59] *Snow Mountain Pine Co. v. Maudlin*, 84 Or App 590, 598-99 (1987).

The Oregon Court of Appeals observed that "[t]o permit a utility to delay the date to be used to calculate the purchase price simply by refusing to purchase energy would expose qualifying facilities to risks that we believe Congress and the Oregon Legislature intended to prevent."[60] Based on this observation, the Court of Appeals concluded that a QF has the power to determine the date for which avoided costs are to be calculated "by tendering an agreement that obligates it to provide power."[61]

A few months after the Oregon Court of Appeals issued its opinion in *Snow Mountain Pine*, the Oregon Public Utility Commissioner adopted an administrative rule governing legally enforceable obligations to specify that a legally enforceable obligation is established the earlier of the date of an executed PPA between the QF and utility or the date, "agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate."[62]

This rule, OAR 860-029-0010(29), which is still in effect, provides,

(29) "Time the obligation to purchase the energy capacity or energy and capacity is incurred" means the earlier of:

(a) The date on which a binding, written obligation is entered into between a qualifying facility and a public utility to deliver energy, capacity, or energy; or

[60] *Id.,* at 599-600.
[61] *Id.*
[62] Order No. 87-1154; *See* OAR 860-029-0010(29).

(b) The date agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate.

**Q. Do you think the Commission's definition of "time of obligation" in OAR 860-029-0010(29) should be changed?**

Yes. The Commission's current rule requiring the utility to agree in writing to certain avoided cost prices before a LEO can be established is little different from requiring the QF to obtain an executed PPA. In both circumstances, the QF's right to sell is dependent on the utility's written agreement. Staff recommends that the Commission establish a policy under which a LEO can be established upon the QF's execution and tendering of a final executable draft contract, if the utility itself does not timely execute this final draft and create an enforceable PPA.

**Q. Why is it appropriate to conclude a LEO can arise on the date the QF executes the final draft executable PPA?**

A. The Commission has to balance the right of the QF to sell its energy with ratepayers' interests in reasonable rates. A QF could argue that it can commit itself to sell power when it first contacts the utility regarding a PPA. However, the Commission should conclude that such a commitment is a LEO only if the QF would be liable for damages for failing to bring its proposed project on-line by the scheduled commercial on-line date. Unless the QF is subject to penalty for non-performance, any "commitment" it makes regarding future sales is essentially non-binding.

But, until certain particulars, such as the scheduled commercial on-line date and the amount of minimum and maximum annual deliveries, are known, it would be difficult to impose the appropriate penalties on a QF for failing to satisfy its commitment to sell power. Once the QF signs the final draft executable contract, which will contain the necessary information regarding the QF's planned operations, the Commission can order that the QF is subject to the penalties included in the draft contract if the QF fails to meet its commitments regarding its planned operations.

**Q. Do all the utilities have a process that results in providing the QF with a final draft executable contract?**

A. PacifiCorp, PGE, and Idaho Power all have similar processes for entering into standard contracts. All require the QF to initiate the standard contracting process by submitting certain information, after which the utilities have fifteen days to provide a draft standard contract.[63] The QF may either agree to the terms of the draft standard contract and ask the utility to provide a final executable contract, or provide comments regarding suggested changes. Thereafter, each utility will provide iterations of the draft standard contract no later than 15 days after each round of comments by the negotiating QF. When the QF indicates that it agrees to all the terms in the draft contract, the utilities have fifteen days to forward to the QF a final executable draft.

**Q. Is the QF's signing of the final draft executable contract the only circumstance in which a LEO may be established?**

[63] Staff Exhibit 504.

A. Staff recommends that the Commission allow QFs the opportunity to establish a LEO earlier in the iterative contracting process described above (utility providing QF contract and QF commenting) if the QF can show that it has provided the information required by the utility's tariff or form of standard contract, the utility has not met the deadlines imposed under its or form of standard contract for providing draft standard contracts, and the QF is committed to deliver energy on the scheduled commercial on-line date and will be subject to the penalties specified in the form of standard contract for failure to do so.

**Q. Why does Staff recommend this alternate way of establishing a LEO?**

A. As noted above, non-contractual LEOs are intended to prevent a utility from circumventing its obligation to purchase QF power by refusing to enter into a contract with the QF. A utility's failure to comply with the timelines in its tariff or form of standard contract for entering into a standard contract could circumvent the QF's ability to enter into a PPA. In these circumstances, the QF should have the ability to establish a LEO even though the utility has not provided it with a final draft executable standard contract.

**Issue 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 provide some background on this issue.**

A. Phase I of this docket included the following issue: Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?[64] Phase I testimony addressed avoided third party transmission costs as well as imposed third party transmission costs. With regard to the latter, the Commission concluded in Order No. 14-058,

> any costs imposed on a utility that are above the utility's avoided costs must be assigned to the QF in order to comport with PURPA avoided cost principles. We find, however, that Staff and the parties did not fully address how to calculate and assign the third party transmission costs that are attributable to the QF. We defer this issue to the second phase of these proceedings.

Order No. 14-058 also lists potential examples of methods to assign these costs: lowering standard avoided cost rates, separately in interconnection cost assessments, and through an addendum as suggested by Pacific Power.

**Q. What is Staff's recommendation?**

A. Staff supports the use of a method that reasonably estimates transmission costs for the term of a QF contract under very specific circumstances. Staff recommends that in cases for which the utility proposes the assignment of third party transmission costs, the utility be required to provide specific and detailed information regarding the load, generation, and transmission capacity values used in making that determination, and into the basis for calculating the amount and cost of the third party transmission that would be required.

**Q. Does Staff have a specific proposal for a methodology?**

A. Not at this time.

**Q. Does this conclude your testimony?**

A. Yes.

[64] Docket No. UM 1610 Ruling issued December 21, 2012, Appendix A, Issues List.

CASE:  UM 1610 PH II
WITNESS: BRITTANY ANDRUS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 501

## Witness Qualifications Statement

**May 22, 2015**

**WITNESS QUALIFICATION STATEMENT**

| | |
|---|---|
| NAME: | Brittany Andrus |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Utility Analyst<br>Energy, Resources and Planning |
| ADDRESS: | 3930 Fairview Industrial Dr. SE<br>Salem, Oregon, 97302-1166 |
| EDUCATION: | M.B.A.<br>Portland State University, Portland, Oregon<br><br>B.A. English<br>Michigan State University, East Lansing, Michigan |
| EXPERIENCE: | I have been employed at the Oregon Public Utility Commission since 2011. My current responsibilities include research, analysis and technical support for electric company proceedings, with an emphasis on resource planning, power costs, and qualifying facilities under PURPA.<br><br>I was previously employed for 17 years by the Bonneville Power Administration, a wholesale power marketing agency within the federal Department of Energy. My duties included energy efficiency planning and program management, long term load and revenue forecasting, long term power sales contracts, rate impact analysis, short term load forecasting, power and transmission scheduling, and management of load forecasting data and processes. |

CASE: UM 1610 PH II
WITNESS: BRITTANY ANDRUS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 502

## Exhibits in Support
## Of Opening Testimony

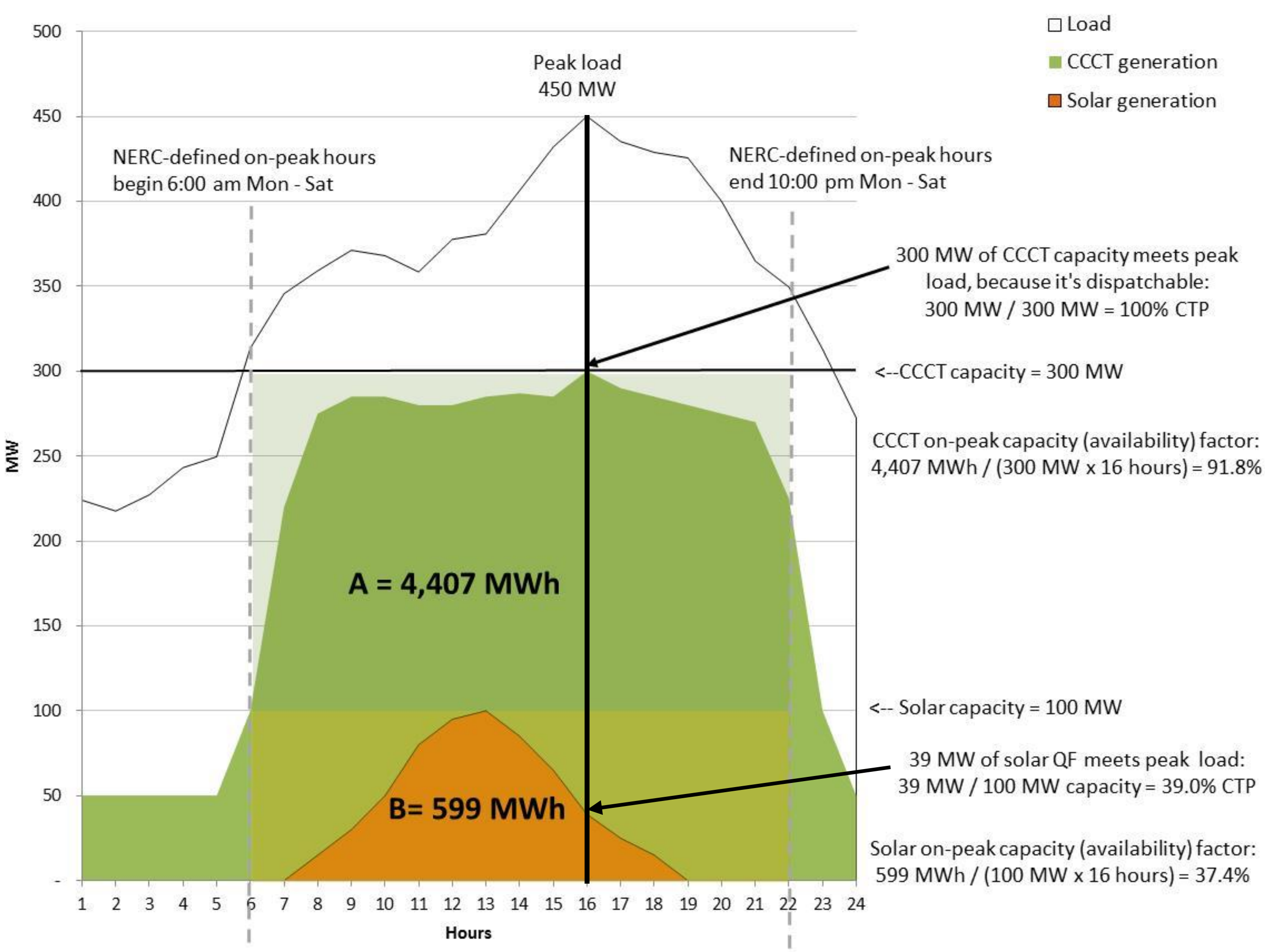
**May 22, 2015**

# Capacity Value and Payment

The image below graphically represents the following inputs to the Staff-recommended calculation of QF capacity payments:

1) utility peak, which establishes the hour(s) in which the capacity is needed;
2) resource contributions to peak for a CCCT and a solar resource. The CTP establishes the quantity of capacity, and hence, its value; and,
3) Generation quantity in MWh of the CCCT and solar resources during on-peak hours.

The annual value of capacity is paid to QFs as an adder to each on-peak MWh of generation over the course of the year. Therefore, the capacity rate per MWh must take into account the on-peak hour expected availability of QFs (in this case, solar at 37.4%), as it does for the CCCT avoided resource (91.8%).



CASE: UM 1610 PH II
WITNESS: BRITTANY ANDRUS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 503

## Exhibits in Support
## Of Opening Testimony

**May 22, 2015**

# Staff Proposed Minimum Filing Requirements

The list below contains the minimum filing requirements (MFRs) to be provided for standard (for qualifying facilities 10 MW or less) avoided cost compliance filings. These MFRs apply to both nonrenewable and renewable standard avoided cost prices. As part of its filing, the utility will provide workpapers, including spreadsheet files in electronic format with formulae intact, supporting the avoided cost prices.

For items directly from the Integrated Resource Plan (IRP), the utility will provide the document name, date, and page number. For items not directly from the IRP, the utility will provide explanations in its application.

| **I. Resource Sufficiency/Deficiency Demarcation** | **IRP Reference** |
|---|---|
| 1. Nonrenewable: Identify the demarcation year for the end of sufficiency period/start of deficiency period. | |
| 2. Non-renewable: Identify the major resource to be acquired (>100 MW and longer than 5 years) at end of sufficiency period. | |
| 3. Renewable: Identify the demarcation year for the end of sufficiency period/start of deficiency period. | |
| 4. Renewable: Identify the major resource to be acquired (>100 MW and longer than 5 years) at end of sufficiency period. | |

| **II. Gas Price Forecast** | **IRP Reference** |
|---|---|
| 1. Identify the source of the gas price forecast. | |
| 2. If the forecast source differs from that used in the most recent approved avoided cost filing, explain the reason(s) for the change. | |
| 3. Provide the yearly forecast price by year, and identify any rounding that has been applied. | |
| 4. Quantify and describe the extent to which the gas price forecast differs from the most recent approved avoided cost filing. Include a description of carbon cost/tax assumption(s). | |

| III. Sufficiency Period Prices | IRP Reference |
|---|---|
| 1. List the market hub(s) used for market price projections, the source for the forward price curves, and any adjustments or blending used in deriving the sufficiency period prices. | |
| 2. Provide the transmission costs assumed used in sufficiency period prices. | |
| 3. Provide all other component(s) used to calculate sufficiency period prices. | |

| IV. Standard Rates Deficiency Period Resource | IRP Reference |
|---|---|
| 1. Provide the resource type, geographic location, nameplate capacity, and annual capacity factor. | |
| 2. Provide the source of natural gas supply, and the costs assumed for interconnection, infrastructure upgrades, transmission, storage, and any other costs necessary to deliver gas. | |
| 3. Provide the assumed heat rate. Include assumptions to account for elevation, temperature, and cooling method. | |
| 4. List the costs assumed for interconnection facilities. | |
| 5. List the components of transmission costs used and their respective values. | |
| 6. List the tax assumptions used. | |

| V. Renewable Rates Deficiency Period Resource | IRP Reference |
|---|---|
| 1. Provide the resource type, geographic location, nameplate capacity, and annual capacity factor. | |
| 2. Provide assumptions used for mechanical availability, annual hours of curtailment, and annual MWh of energy curtailed. | |
| 3. List the costs assumed for interconnection facilities. | |
| 4. List the components of transmission costs used and their respective values. | |
| 5. List the tax assumptions used. This includes assumed taxes paid (federal, state, local), and assumed tax benefits (e.g., PTC, ITC, grants in lieu of credits). | |
| 6. Provide the capacity contribution value, and the method used to derive the capacity contribution value, for solar and wind resource types. | |
| 7. Provide the wind integration cost used, and the method used to derive the wind integration cost. | |

CASE: UM 1610 PH II
WITNESS: BRITTANY ANDRUS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 504

## Exhibits in Support
## Of Opening Testimony

**May 22, 2015**

# Processes for Entering into Standard Contracts

**Pacific Power, Schedule 37**

I. Process for Completing a Power Purchase Agreement

B. Procedures

1. The Company's approved generic or standard form power purchase agreements may be obtained from the Company's website at www.pacificorp.com, or if the owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

2. In order to obtain a project specific draft power purchase agreement the owner must provide in writing to the Company, general project information required for the completion of a power purchase agreement, including, but not limited to:

   (a) demonstration of ability to obtain QF status;
   (b) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
   (c) generation technology and other related technology applicable to the site;
   (d) proposed site location;
   (e) schedule of monthly power deliveries;
   (f) calculation or determination of minimum and maximum annual deliveries;
   (g) motive force or fuel plan;
   (h) proposed on-line date and other significant dates required to complete the milestones;
   (i) proposed contract term and pricing provisions as defined in this Schedule (i.e., standard fixed price, renewable fixed price);
   (j) status of interconnection or transmission arrangements;
   (k) point of delivery or interconnection;

3. The Company shall provide a draft power purchase agreement when all information described in Paragraph 2 above has been received in writing from the QF owner. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the

owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Public Utility Commission of Oregon in this Schedule 37.

4. If the owner desires to proceed with the power purchase agreement after reviewing the Company's draft power purchase agreement, it may request in writing that the Company prepare a final draft power purchase agreement. In connection with such request, the owner must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft power purchase agreement. Within 15 business days following receipt of all information requested by the Company in this paragraph 4, the Company will provide the owner with a final draft power purchase agreement.

5. After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

6. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company’s execution a completely executed copy will be returned to the owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

**Idaho Power, Schedule 85**

b. Procedures

i. The Company's approved Energy Sales Agreement may be obtained from the Company's website at http://www.idahopower.com or if the Seller is unable to obtain it from the website, the Company will send a copy within 10 business days of a written request.

ii. In order to obtain a project specific draft Energy Sales Agreement the Seller must provide in writing to the Company, general project information required for the completion of an Energy Sales Agreement, including, but not limited to:

a) Date of request
b) Company / Organization that will be the contracting party
c) Contract notification information including name, address and telephone number
d) Verification that the Qualifying Facility meets the "Eligibility for Standard Rates and Contract" criteria
e) Copy of the Qualifying Facility's QF certificate
f) Copy of the FERC license (applicable to hydro projects only)
g) Location of the proposed project including general area and specific legal property description
h) Description of the proposed project including specific equipment models, types, sizes and configurations
i) Type of project (wind, hydro, geothermal etc)
j) Nameplate capacity of the proposed project
k) Schedule 85 pricing option selected
l) Desired term of the Energy Sales Agreement
m) Annual net energy amount
n) Maximum capacity of the Qualifying Facility
o) Estimated first energy date
p) Estimated operation date
q) Point of Delivery
r) Status of the Generation Interconnection Process

iii. The Company shall provide a draft Energy Sales Agreement when all information described in Paragraph 2 above has been received in writing from the Seller. Within 15 business days following receipt of all information required in Paragraph 2 the Company will provide the Seller with a draft Energy Sales Agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Oregon Public Utility Commission in this Schedule.

iv. The Company will respond within 15 business days to any written comments and proposals that the Seller provides in response to the draft Energy Sales Agreement.

v. If the Seller desires to proceed with the Energy Sales Agreement after reviewing the Company's draft Energy Sales Agreement, it may request in writing that the Company prepare a final draft Energy Sales Agreement. In connection with such request, the Seller must provide the Company with an updated status of the Generation Interconnection Process which indicates that the Seller's provided information (i.e. first energy date, operation date, etc.) are realistically attainable and any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Energy Sales Agreement. Once the Company has received the written request for a final draft Energy Sales Agreement and all additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Energy Sales Agreement, the Company will provide Seller with a final draft Energy Sales Agreement within 15 business days.

vi. After reviewing the final draft Energy Sales Agreement, the Seller may either prepare another set of written comments and proposals or approve the final draft Energy Sales Agreement. If the Seller prepares written comments and proposals, the Company will respond within 15 business days to those comments and proposals.

vii. When both parties are in full agreement as to all terms and conditions of the final draft Energy Sales Agreement, the Company will prepare and forward to the Seller within 15 business days a final executable version of the Energy Sales Agreement. Once the Seller executes the Energy Sales Agreement and returns all copies to the Company, the Company will execute the Energy Sales Agreement. Following the Company's execution a completely executed copy will be returned to the Seller. Prices and other terms and conditions in the Energy Sales Agreement will not be final and binding until the Energy Sales Agreement has been executed by both parties.

**Portland General Electric, Schedule 201**

**GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA**

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.