



# Oregon

ate Brown. Governor

## **Public Utility Commission**

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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*

Kay Barnes

Filing on Behalf of Public Utility Commission Staff

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**PUBLIC UTILITY COMMISSION  
OF OREGON**

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**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**

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

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

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

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

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

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

- 12 1. Who owns the Green Tags during the last five years of a 20-year fixed price  
13 Power Purchase Agreement (PPA) during which prices paid to the QF are at  
14 market?
- 15 2. Should avoided transmission costs for non-renewable and renewable proxy  
16 resources be included in the calculation of avoided cost prices?
- 17 3. Should the Commission revise the methodology approved in Order No.14-058  
18 for determining the capacity contribution adder for solar QFs selecting  
19 standard renewable avoided cost prices? If so, how?
- 20 4. Should the capacity contribution calculation for standard non-renewable  
21 avoided cost prices be modified to mirror any change to the solar capacity  
22 contribution calculation used to calculate the standard renewable avoided cost  
23 price?

- 1 5. What is the appropriate forum to resolve disputed issues and assumptions?
- 2 6. Do the market prices used during the Resource Sufficiency Period sufficiently
- 3 compensate for capacity?
- 4 7. What is the most appropriate methodology for calculating non-standard
- 5 avoided cost prices? Should the methodology be the same for all three
- 6 electric utilities operating in Oregon?
- 7 8. When is there a legally enforceable obligation?
- 8 9. How should third-party transmission costs to move QF output in a load pocket
- 9 to load be calculated and accounted for in the standard contract?

10 **Issue 1: Who owns the Green Tags during the last five years of a 20-year**

11 **fixed price PPA during which prices paid to the QF are at market?**

12 **Q. Please explain Issue No. 1 regarding ownership of renewable energy**

13 **credits (RECs) during the last five years of a 20-year standard contract.**

14 A. The question presented is whether QFs selling power to utilities under the

15 Standard Renewable Avoided Cost price stream must cede RECs to the

16 utilities during periods of renewable resource deficiency that coincide with the

17 last five years of a 20-year standard contract during which the QFs are

18 compensated at market-based prices.

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

20 A. As explained below, Staff believes the Commission's previous orders make

21 clear that a QF must transfer RECs to utilities under the standard contract

22 when compensated for them with deficiency-period Standard Renewable

23 Avoided Cost prices.

1 **Q. Why do QFs receive market-based prices during the last five years of a**  
2 **20-year standard contract even if the utility is resource deficient?**

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

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

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

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<sup>1</sup> Order No. 05-584 at 19-20.

<sup>2</sup> Order No. 05-584 at 20.

<sup>3</sup> Order No. 05-584 at 20.

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

5 During periods of renewable resource sufficiency, the rate will be  
6 based on market prices. During periods of renewable resource  
7 deficiency, the rate will be based on the renewable avoided cost of the  
8 next utility renewable resource acquisition in that utility's IRP. *The*  
9 *renewable resource QF will keep all associated Renewable Energy*  
10 *Certificates (RECs) during periods of renewable resource sufficiency,*  
11 *but will transfer those RECs to the purchasing utility during periods of*  
12 *renewable resource deficiency.*<sup>4</sup>

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

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

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

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

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<sup>4</sup> Order No. 11-505 at 1 (emphasis added).

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

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

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

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

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<sup>5</sup> Order No. 11-505 at 1.

<sup>6</sup> Order No. 11-505 at 7.

<sup>7</sup> Order No. 11-505 at 9.

<sup>8</sup> Order No. 11-505 at 9.



1           These QFs should be offered an avoided cost stream that reflects the costs  
2           that the utility will avoid.”<sup>9</sup>

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

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

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

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

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<sup>9</sup> 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.”).

<sup>10</sup> Order No. 11-505 at 9.

<sup>11</sup> Order No. 11-505 at 7.

<sup>12</sup> Order No. 11-505 at 7.

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

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

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

9 We affirm the existing policy that if the proxy resource used to  
10 calculate a utility's avoided costs is an off-system resource, the  
11 costs of the third-party transmission are avoided, and are therefore  
12 included in the calculation of avoided cost prices. This is the  
13 situation for PGE, and it was not contested in these proceedings.

14 If the proxy resource used to calculate a utility's avoided costs is  
15 an on-system resource, there are no avoided transmission costs,  
16 and thus the costs of third-party transmission are not included in  
17 the calculation of avoided costs prices. This is the situation for  
18 Pacific Power.<sup>13</sup>

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

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<sup>13</sup> Order No. 14-058 at 17.

1 warranted, *as opposed to raising any additional or unanswered question(s) in*  
2 *Phase II of this docket.*"<sup>14</sup>

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

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

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<sup>14</sup> Order No. 14-229 at (Order denying reconsideration) (emphasis added).

<sup>15</sup> 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.).

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

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

7 A. Some of the parties believe that PacifiCorp would have to incur transmission  
8 costs for its next avoidable renewable resource indicated by its 2013  
9 Integrated Resource Plan. PacifiCorp's 2013 IRP indicates that the next  
10 deferrable renewable resource is Wyoming wind.<sup>16</sup>

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

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

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<sup>16</sup> PacifiCorp 2013 Integrated Resource Plan, Table 8.7 – PacifiCorp's 2013 IRP Preferred Portfolio at 227.

<sup>17</sup> PacifiCorp 2013 Integrated Resource Plan, Table 6.10 – Cumulative Wind Selection Limits by Year and Energy Gateway Scenario.

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

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

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

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

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

16 A. Yes. Staff recommends that the Commission clarify that neither  
17 avoided third-party transmission costs nor costs to build a transmission  
18 resource will be included in the calculation of avoided cost prices when  
19 they are not avoided whether the avoidable resource is on-system or  
20 off. Staff also recommends that the Commission clarify that such costs  
21 should be included in the calculation of avoided cost prices if the utility's  
22 IRP indicates the utility's purchase from the QF allows the utility to

1 avoid them, or if this fact is established in the review process following  
2 the utility's avoided cost filing.

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

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

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

14 **Q. Please explain this issue.**

15 A. In Phase I of this investigation, Staff recommended that the Commission  
16 modify the methodology for calculating Standard Non-renewable and  
17 Renewable Avoided Cost prices offered during on-peak hours during resource  
18 deficiency periods so that the prices reflect the inherently different  
19 contributions to peak (CTP) load of different QF resource types.<sup>18</sup> The  
20 Commission adopted Staff's recommended adjustments.<sup>19</sup>  
21 Subsequently, Obsidian Renewables, LLC (Obsidian) asked the Commission  
22 to reconsider its order adopting the Staff capacity contribution adjustment for

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<sup>18</sup> Staff/100 and/200.

<sup>19</sup> Order No. 14-058 at

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

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

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

$$\text{Capacity Factor} = \text{Energy} / (\text{Capacity} \times \text{hours})$$

18 For annual capacity factors, the time period is one year, or 8760 hours (8,784  
19 hours in a leap year). An on-peak<sup>21</sup> capacity factor is the same ratio, but  
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<sup>20</sup> Obsidian, LLC's April 24, 2014 Motion for Clarification at 2.

<sup>21</sup> 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.

1 over only the on-peak hours. On-peak hours are 56 to 57 percent of the  
2 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%	

3  
4 So, the on-peak capacity factor is the same calculation using the number of  
5 on-peak hours, as follows:

$$6 \text{ On-peak Capacity Factor} = \text{On-peak Energy} / (\text{Capacity} \times \text{On-peak hours})$$

7 The CTP is the percentage of a resource's capacity expected to be  
8 generating during a utility's peak load.<sup>22</sup> There are different methods for  
9 calculating a resource's CTP. How to calculate a resource's CTP is not at  
10 issue in this investigation. The only question is how to account for a  
11 resource's CTP when calculating avoided cost prices.

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<sup>22</sup> Staff/300, Andrus/5.



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

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

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

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

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

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<sup>23</sup> Order No. 14-058 at 2.

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

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

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

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

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

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

1 Order No. 14-058 (“Current Method”), and the revised method Staff proposed  
2 after the Commission granted reconsideration (“Proposed Method”).<sup>24</sup>

3 Under the Previous Method, a solar QF could expect to receive a percentage  
4 of the utility’s total avoidable capacity costs roughly equal to that QF’s on-  
5 peak capacity factor. The example shows that an individual QF resource with  
6 an on-peak capacity factor of 27.5 percent, could expect annual capacity  
7 payments equal to approximately 30 percent of the utility’s avoided capacity  
8 costs used for the avoided cost calculation.<sup>25</sup>

9 Under the Current Method, the same solar QF could expect to receive less  
10 than three percent of the utility’s annual avoided costs for capacity.<sup>26</sup> Finally,  
11 under the Proposed Method, the same solar QF could expect to receive  
12 annual payments for avoided capacity roughly equal to the solar resource’s  
13 CTP of 13.6 percent.<sup>27</sup>

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

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

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<sup>24</sup> Staff/400, Andrus/5.

<sup>25</sup> Staff/400, Andrus/5.

<sup>26</sup> Staff/400, Andrus/5.

<sup>27</sup> Staff/400, Andrus/5.

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

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

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

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

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

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

7 A. First, adjust the CTP of the proxy renewable resource to account for the CTP  
8 of solar resources relative to the renewable avoided resource, which is wind.

9 Then, apply that differential to the value of capacity:

10  $(\text{CTP of solar minus CTP of wind}) \times \text{value of capacity} = \text{value of solar capacity}$

11  $(39\% - 5\%) \times \$104/\text{kW-year} = \$35.36/\text{kW-year solar capacity value, or}$

12  $\$35,360/\text{MW-year}$

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

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

17  $\text{Value of solar capacity per MW per year} / (\text{solar on-peak capacity factor}$   
18  $\times \text{on-peak hours/year})$

19  $\$40,560/\text{MW-year} / (37.4\% \times 4,912) = \$22.08 \text{ per On-peak MWh}$

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

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

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

8 **CTP:**

9 300 MW CCCT

10 Generation at hour of peak / Capacity = CTP

11 300 MW / 300 MW = 100 percent CTP

12 100 MW Solar QF:

13 Generation at hour of peak / Capacity = CTP

14 39 MW / 100 MW = 39.0 percent CTP

15 **On-peak Capacity Factor:**

16 300 MW CCCT:

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

19 4,405 MWh / (16 hours \* 300 MW) = 91.8 percent On-peak

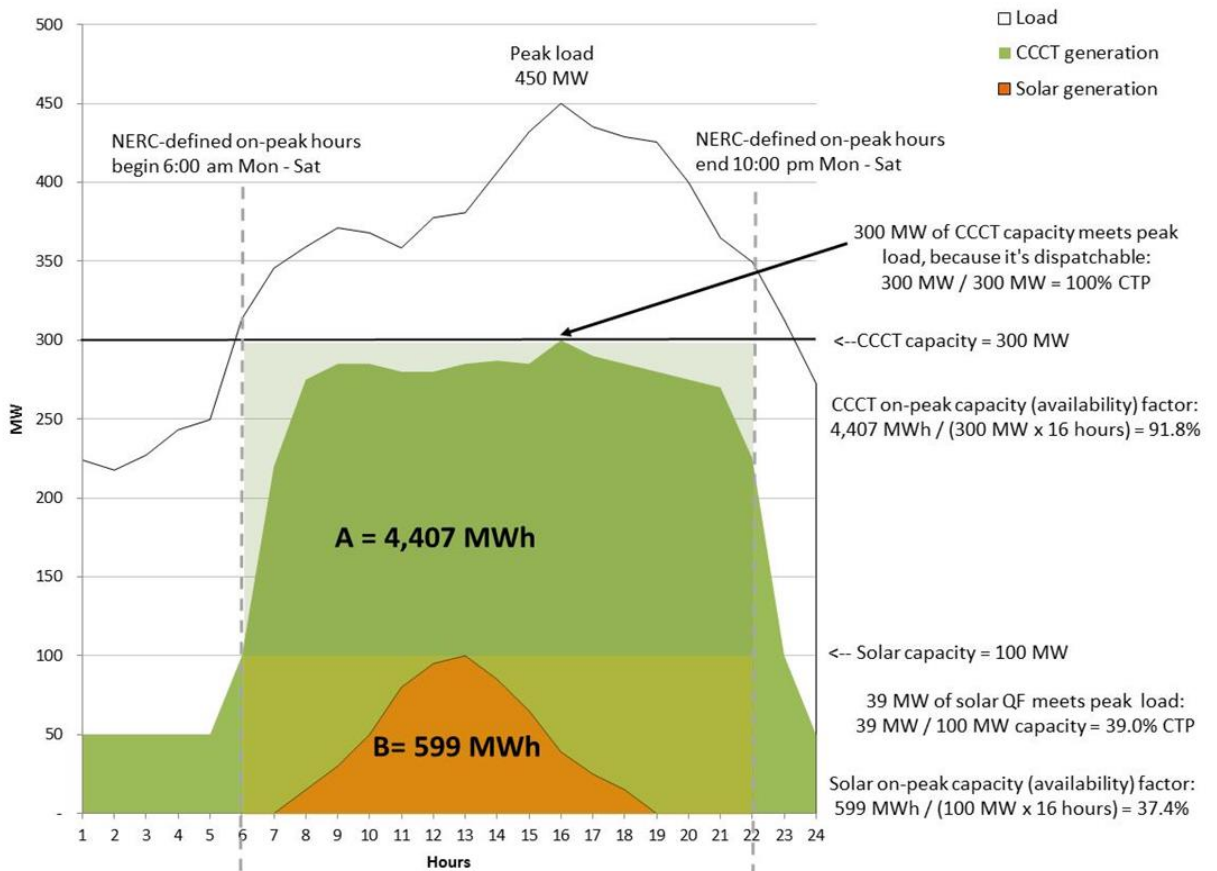
20 capacity factor

21 100 MW Solar QF:

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

1 599 MWh / (16 hours \* 100 MW) = 37.4 percent On-peak  
 2 capacity factor

3 Figure 1.



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

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

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

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

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

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

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

19 
$$\frac{(\text{Value of capacity} \times \text{CTP} \times \text{QF Capacity})}{$$

20 
$$\text{On-peak availability factor} \times \text{On-peak hours}$$



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

3 **Q. Please explain this issue.**

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

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

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

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

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

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

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<sup>28</sup> Order No. 05-584 at 36-37.

<sup>29</sup> Order No. 06-538 at 44.

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

4 (4) Standard rates for purchases shall be implemented as follows:

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

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

17 (3) Each public utility shall file with the Commission draft avoided-cost  
18 information with its least-cost plan pursuant to Order No. 89-507  
19 and file final avoided-cost information within 30 days of  
20 Commission acknowledgment of the least-cost plan to be effective  
21 30 days after filing.

22 \* \* \* \* \*

23 (6) State review: Any data submitted by a public utility under this rule  
24 shall be subject to review and approval by the Commission. In any  
25 such review, the public utility has the burden of supporting and  
26 justifying its data. *Any standard rates filed under OAR 860-029-*  
27 *0040 shall be subject to suspension and modification by the*  
28 *Commission.*<sup>30</sup>

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

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<sup>30</sup> Emphasis added.

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

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

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

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

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

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

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<sup>31</sup> Order No. 10-488 at 8.

<sup>32</sup> Order No. 11-505 at 6.

1 **Q. What does Staff recommend?**

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

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

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

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<sup>33</sup> 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.").

<sup>34</sup> See Order No. 05-584 at 36-37 and Order No. 06-538 at 44.

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

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

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

12 A. Yes. Staff recommends that the Commission require utilities to satisfy  
13 minimum filing requirements "MFRs" when they make avoided cost filings.  
14 Currently, it can be difficult to discern from each utility's avoided cost filing  
15 what inputs the utility used to calculate avoided cost prices. It generally takes  
16 a few rounds of discovery before Staff can ascertain the basis for the utility's  
17 calculation of avoided costs. The need for discovery to determine the basis of  
18 the utility's avoided cost calculations can trigger a Staff request to suspend the  
19 utilities' avoided cost filing to allow opportunity to investigate.  
20 Staff believes that requiring utilities to file certain information with their avoided  
21 cost filings may significantly decrease the need for discovery and hasten  
22 implementation of updated avoided cost rates.

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

2 A. Staff includes a list detailing the MFRs at Exhibit 503. The MFRs require the  
3 utilities to identify information such as the year demarcating between resource  
4 sufficiency and deficiency periods, the location and nameplate capacity of the  
5 utility's proxy resource, and the source of the utility's gas price forecast.<sup>35</sup>

6 Below is an excerpt of Exhibit 502 to provide an example of a few of the  
7 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

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

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

<sup>35</sup> Staff Exhibit 503 (Staff Proposed Minimum Filing Requirements).

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

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

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

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

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

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

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<sup>36</sup> See Order No. 05-584 at 26-27; Order No. 06-538 at 44.

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

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

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

13 Prior to 2005, the Commission traditionally based sufficiency period avoided  
14 cost prices on the variable costs of operating existing generating resources.<sup>40</sup>

15 Staff and other parties challenged this calculation in Docket No. UM 1182  
16 because it included no capacity payment.<sup>41</sup>

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

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<sup>37</sup> Order No. 05-584 at 26.

<sup>38</sup> Order No. 05-584 at 26.

<sup>39</sup> Order No. 05-584 at 26.

<sup>40</sup> 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.)

<sup>41</sup> Order No. 05-584 at 27.

<sup>42</sup> Order No. 05-584 at 28.



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

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

10 We find this valuation mechanism to be appropriate given the  
11 likelihood that a utility will address probable gaps between increasing  
12 demand and actual resources, in the absence of incremental QF  
13 capacity, with purchases of energy and capacity on the market.  
14 Indeed, we find PGE's recent history of buying significant resources  
15 on the market prior to a commitment to build a new utility plant to be  
16 illustrative.<sup>45</sup>

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

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

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<sup>43</sup> Order No. 05-584 at 28.

<sup>44</sup> Order No. 05-584 at 28.

<sup>45</sup> Order No. 05-584 at 28.

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

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

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

8 A. In Order No. 10-488, the Commission determined that for both two-year and  
9 post-IRP avoided cost filings, "the start date of the first major resource in the  
10 action plan of the most recent acknowledged IRP demarcates the resource  
11 sufficiency and deficiency periods."<sup>46</sup> The Commission used the definition of  
12 "major resource" that is used in the Commission's competitive bidding rules,  
13 which is a resource that is at least five years in duration and at least  
14 100 MW.<sup>47</sup>

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

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

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<sup>46</sup> Order No. 10-488 at 3 (internal quotations omitted).

<sup>47</sup> 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).

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

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

6 A. Order No. 07-360 established guidelines for negotiated, non-standard  
7 contracts between utilities and large QFs. Large QFs are those greater than  
8 10 MW nameplate capacity.

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

- 10 ○ For PGE and PacifiCorp, the yearly avoided costs approved for the  
11 20-year period for standard contracts should serve as the starting  
12 point for negotiations. The prices may be modified to address  
13 specific enumerated factors approved by the Oregon Commission.  
14 The utility will provide to the QF a description of the methodology  
15 for each adjustment to standard avoided costs and how each  
16 adjustment was made.<sup>48</sup>
- 17 ○ For Idaho Power, the starting point for negotiations are the avoided  
18 costs calculated under the modeling methodology approved by the  
19 Idaho Public Utilities Commission for QFs over 10 MW, as refined  
20 by the Oregon Commission to incorporate stochastic analyses of  
21 electric and natural gas prices, loads, hydro and unplanned  
22 outages.<sup>49</sup>

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

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<sup>48</sup> Order No. 07-360, Appendix A, "Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs 10 MW or Larger."

<sup>49</sup> Order No. 07-360, Appendix A, "Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs 10 MW or Larger."

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

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

12 A. Three.

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

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

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<sup>50</sup> UM 1610 Phase I PAC/100, Dickman/7.

1 QF with energy at zero cost, and with the capacity of the next deferrable  
2 resource reduced proportionately to the proposed QF's capacity contribution.<sup>51</sup>

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

6 A. The Standard Non-Renewable Avoided Cost prices during the deficiency  
7 period are based on the fixed and variable costs of a combined cycle  
8 combustion turbine (CCCT), split into its energy and capacity components.  
9 It is a generic calculation that does not take into account the specific  
10 operations of a utility's system. This method is appropriate for QFs under the  
11 10 MW standard eligibility cap because in that it provides transparency in  
12 exchange for its lack of precision. The complexity of the modeling approach  
13 for larger QFs is justified, as it is likely to provide a more accurate  
14 quantification of the impact of a QF based on its specific characteristics than a  
15 generic CCCT calculation with adjustments applied to it. To put it simply, an  
16 estimate (the adjustments) overlaid onto a simplified estimate (the avoided  
17 CCCT resource) will likely be less accurate than a single complex estimate.

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

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

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<sup>51</sup> UM 1610 Phase I, PAC/100, Dickman/7-10.

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

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

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

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

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

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

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

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<sup>52</sup> Order No. 07-360, Appendix A, "Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs 10 MW or Larger."

<sup>53</sup> Phase I UM 1610 Idaho Power/200, Stokes/29-32.

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

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

3 A. Under PURPA, a QF can sell its generation to a utility “as available” or  
4 “pursuant to a legally enforceable obligation.”<sup>54</sup> For sales pursuant to a legally  
5 enforceable obligation (LEO) the QF can choose to have prices based on  
6 avoided costs calculated at the time of the LEO or at the time the QF  
7 commences delivery to the utility.<sup>55</sup> In most transactions between QFs and  
8 utilities, the LEO arises when both the QF and the utility execute a power  
9 purchase agreement (PPA). However, as explained below, limiting the  
10 creation of a LEO to an executed agreement likely conflicts with PURPA and  
11 with Oregon’s statutes implementing PURPA.

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

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

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

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

18 Section 292.304(d) and the requirement that a QF can sell and a  
19 utility must purchase pursuant to a legally enforceable obligation  
20 were specifically adopted to prevent utilities from circumventing the  
21 requirement of PURPA that utilities purchase energy and capacity  
22 from QFs. The Commission explained [in Order No. 69 adopting  
23 rules to implement PURPA]:

24 Paragraph (d)(2) permits a qualifying facility to enter  
25 into a contract or other enforceable obligation to

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<sup>54</sup> 18 C.F.R. §292.304(d).

<sup>55</sup> 18 C.F.R. §292.304(d).

1 provide energy or capacity over a specified term. *Use*  
2 *of the term “legally enforceable obligation” is intended*  
3 *to prevent a utility from circumventing the requirement*  
4 *that provides capacity credit for an eligible facility*  
5 *merely by refusing to enter into a contract with a*  
6 *qualifying facility.*<sup>56</sup>

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

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

23 is not governed by common law concepts of contract law; it is  
24 created by statutes, regulations and administrative rules. ORS  
25 758.525 requires a utility to purchase power from a qualifying facility.  
26 Similarly, 18 C.F.R. §292.303(a) and OAR 860-020-0030 provide  
27 that an electric utility “shall purchase” any energy and capacity  
28 “which is made available from a QF.” Thus, the obligation to  
29 purchase power is imposed by law on a utility; it is not voluntarily  
30 assumed.<sup>59</sup>

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<sup>56</sup> *Cedar Creek Wind, LLC*, 137 FERC 61006 (2011 WL 4710848), *quoting* Order No. 69, FERC Stats. & Regs. 30,128 at 30,889 (emphasis added).

<sup>57</sup> *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).

<sup>58</sup> *Id.*, *citing JD Wind 1*, 129 FERC 61,148 at p 25.

<sup>59</sup> *Snow Mountain Pine Co. v. Maudlin*, 84 Or App 590, 598-99 (1987).



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

8 A few months after the Oregon Court of Appeals issued its opinion in *Snow*  
9 *Mountain Pine*, the Oregon Public Utility Commissioner adopted an  
10 administrative rule governing legally enforceable obligations to specify that a  
11 legally enforceable obligation is established the earlier of the date of an  
12 executed PPA between the QF and utility or the date, “agreed to, in writing, by  
13 the qualifying facility and the electric utility as the date the obligation is  
14 incurred for the purposes of calculating the applicable rate.”<sup>62</sup>

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

16 (29) “Time the obligation to purchase the energy capacity or energy and  
17 capacity is incurred” means the earlier of:

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

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<sup>60</sup> *Id.*, at 599-600.

<sup>61</sup> *Id.*

<sup>62</sup> Order No. 87-1154; See OAR 860-029-0010(29).

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

4 **Q. Do you think the Commission's definition of "time of obligation" in OAR**  
5 **860-029-0010(29) should be changed?**

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

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

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

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

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

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

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

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<sup>63</sup> Staff Exhibit 504.

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

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

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

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

21 **Q. Please provide some background on this issue.**

22 A. Phase I of this docket included the following issue: Should the costs or  
23 benefits associated with third party transmission be included in the calculation

1 of avoided cost prices or otherwise accounted for in the standard contract?<sup>64</sup>

2 Phase I testimony addressed avoided third party transmission costs as well as

3 imposed third party transmission costs. With regard to the latter, the

4 Commission concluded in Order No. 14-058,

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

11 Order No. 14-058 also lists potential examples of methods to assign these

12 costs: lowering standard avoided cost rates, separately in interconnection cost

13 assessments, and through an addendum as suggested by Pacific Power.

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

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

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

23 A. Not at this time.

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

25 A. Yes.

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<sup>64</sup> 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**

Staff/501  
Andrus/1

## WITNESS QUALIFICATION STATEMENT

NAME: Brittany Andrus

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst  
Energy, Resources and Planning

ADDRESS: 3930 Fairview Industrial Dr. SE  
Salem, Oregon, 97302-1166

EDUCATION: M.B.A.  
Portland State University, Portland, Oregon

B.A. English  
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.

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**

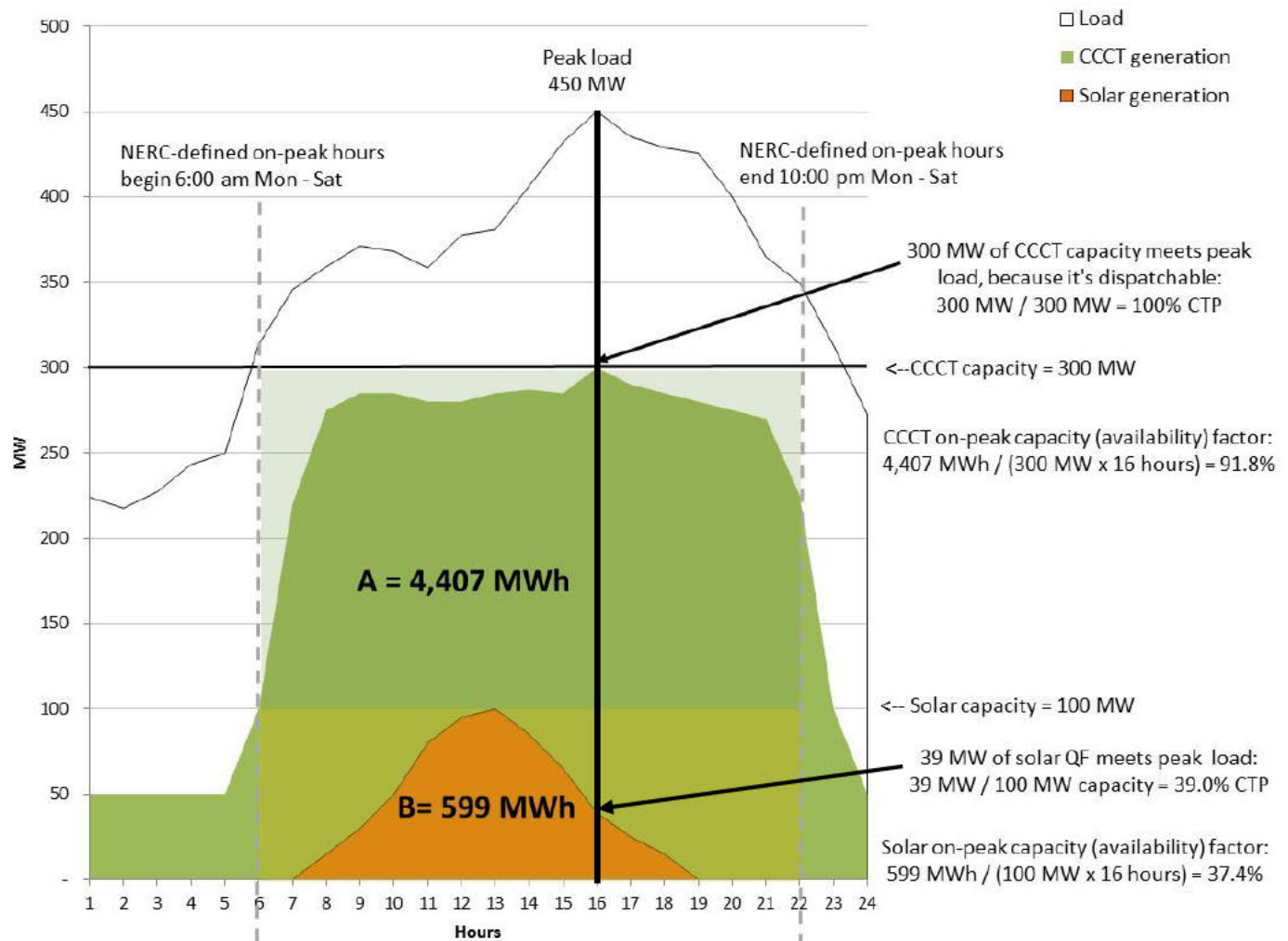


## Capacity Value and Payment

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  
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**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.

<b>I. Resource Sufficiency/Deficiency Demarcation</b>	<b>IRP Reference</b>
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.	

<b>II. Gas Price Forecast</b>	<b>IRP Reference</b>
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  
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**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.pacificcorp.com](http://www.pacificcorp.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.