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July 24, 2015

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

**Re: UM 1610 – In the Matter of OREGON PUBLIC UTILITY COMMISSION, Investigation
into Qualifying Facility Contracting and Pricing**

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic copy of Idaho Power Company's Response Testimony of Michael J. Youngblood and Response Testimony of Randy Allphin.

Please contact this office with any questions.

Very truly yours,

Handwritten signature of Wendy McIndoo in cursive script.

Wendy McIndoo
Office Manager

Attachments

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1610
PHASE II

In the Matter of)
)
PUBLIC UTILITY COMMISSION OF)
OREGON)
)
Investigation into Qualifying Facility)
Contracting and Pricing.)
_____)

IDAHO POWER COMPANY
RESPONSE TESTIMONY
OF
MICHAEL J. YOUNGBLOOD

July 24, 2015

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

2 A. My name is Michael J. Youngblood and my business address is 1221 West Idaho
3 Street, Boise, Idaho 83702.

4 **Q. Are you the same Michael J. Youngblood who previously testified in this
5 docket?**

6 A. Yes. My witness qualifications are set forth in my Direct Testimony, Idaho Power/800.

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

8 A. The purpose of my testimony is to respond to the direct testimony filed May 22, 2015,
9 in Phase II of Docket No. UM 1610. In total, I am responding to the direct testimonies
10 of Staff, Oregon Department of Energy ("ODOE"), the Renewable Energy Coalition
11 ("REC" or "Coalition"), Community Renewable Energy Association ("CREA"),
12 OneEnergy, Obsidian Renewables, LLC ("Obsidian"), collectively referred to as the
13 Intervenors, regarding the Issue List items numbers 3, 4, and 6. I will also address
14 comments made by the other two utilities, Portland General Electric ("PGE") and
15 PacifiCorp d/b/a Pacific Power ("PacifiCorp "). There was one additional intervenor,
16 Gardner Capital Solar Development, LLC ("Gardner Capital") who provided direct
17 testimony. Idaho Power's response to Gardner Capital will be a part of Mr. Allphin's
18 Response Testimony. I will also briefly address the Public Utility Commission of
19 Oregon's ("Commission") direction regarding solar integration charges.

20 **Q. Would you please describe Issues 3, 4 and 6?**

21 A. Issues 3 and 4 are very closely related. They address the question as to whether the
22 methodology approved in Order No. 14-058 for determining both renewable avoided
23 cost prices (Issue 3) and standard non-renewable avoided cost prices (Issue 4) should
24 be modified as to how the capacity contribution calculation has been implemented.
25 Issue 6 addresses whether or not market prices used during the Resource Sufficiency
26 Period sufficiently compensate for capacity.

1 **Q. Please discuss the history regarding Issues 3 and 4.**

2 A. The entire rationale regarding the expected capacity contribution of differing QF
3 resource types was initially discussed by the utilities in their opening testimony in
4 Docket No. UM 1610, filed February 4, 2013. Staff and the Intervenors responded in
5 their testimonies filed March 18, 2013. At that time, Staff witness Adam Bless
6 recommended adjusting the capacity component in both the standard and renewable
7 avoided cost prices to capture the expected capacity contribution of each QF resource
8 type. Staff/100, Bless/23. The Commission ultimately ruled in that docket on February
9 24, 2014, Order No. 14-058:

10 "We agree on the need to adjust for capacity contribution of
11 each resource type and adopt Staff's proposed method for
12 calculating capacity adjustments, as set forth in Staff/102-103,
13 using input estimates derived from the utility's acknowledged
14 IRP. We direct the parties to address issues regarding
15 calculation methodology in future utility IRPs."

16 Following the Commission's ruling allowing reconsideration of the capacity
17 contribution calculation adopted by the Commission Order No. 14-058, parties again
18 addressed this issue on an expedited basis with testimony, response testimony, and
19 briefs filed November 4, 2014, and November 19, 2014, and December 18, 2014,
20 respectively. This issue has not yet been resolved, and in fact, the Administrative Law
21 Judges ("ALJ") instructed the parties that additional discussion on the solar capacity
22 contribution issues previously briefed by the parties is appropriate and in its March 26,
23 2015 Ruling, included the issue in the list of issues to be address in the Phase II
24 procedural schedule. On May 22, 2015, all parties again addressed the solar capacity
25 contribution issue through their opening testimony regarding issues 3 and 4 of the
26 Issue List. With this Response Testimony being filed today, July 24, 2015, we once
again speak to this issue.

Q. What are the Staff/Intervenors' positions regarding Issues 3 and 4?

1 A. As I reviewed the direct testimony regarding Issues 3 and 4, it has become clear that
2 after the extensive testimony and discussions surrounding this particular topic, the
3 issue seems even more convoluted than ever before. The parties seem to have fallen
4 into two camps, and are entrenched. The utilities believe that the capacity contribution
5 modification that was approved in Order No. 14-058 is appropriate, and more closely
6 determines the value of capacity provided by differing QF resource types in
7 determining published avoided cost rates using the proxy method. Staff, who is now
8 represented by Brittany Andrus, and the rest of the Intervenors, believe that the
9 adjustment methodology adopted by the Commission had the “unintended effect” of
10 applying two decrementing adjustments to the capacity payments received by solar
11 QFs during deficiency periods. This difference of opinion regarding the intent of the
12 Commission order becomes apparent even in the way the discussion regarding the
13 recommendation is characterized. Ms. Andrus mischaracterizes Staff’s original
14 recommendation by stating that “Staff recommended that the Commission modify the
15 methodology for calculating Standard non-renewable and Renewable Avoided Cost
16 prices *offered during on-peak hours during resource deficiency periods so that prices*
17 *reflect the inherently different contributions to peak (CTP) load of different QF resource*
18 *types.”* (emphasis added) Staff/500, Andrus/11. While the language differences are
19 subtle and nuanced, I believe they soften the original recommendation the
20 Commission ultimately adopted, which was “Staff recommends adjusting the capacity
21 component in both the standard and renewable avoided cost prices *to capture the*
22 *expected capacity contribution of each QF resource type.”* (emphasis added)
23 Staff/100, Bless/23. I believe that Staff Witness Bless fully understood that the
24 *expected capacity contribution* of differing resource types was less than the proxy
25 Combined Cycle Combustion Turbine (“CCCT”) as well as providing different *expected*
26 *capacity contributions* between QF resources, like wind and solar.

1 **Q. Does the approved methodology for determining avoided cost prices contain**
2 **the “unintended effect” of applying two decrementing adjustments to the**
3 **capacity payments received by solar QFs during deficiency periods?**

4 A. No, it does not. In order to explain further, let me describe what the Staff/Intervenors
5 contend are the two decrementing adjustments to the capacity payments. First,
6 Obsidian initially brought forth the second discount concept in its Motion for
7 Clarification to Order No. 14-058. Obsidian described Staff’s Witness Bless’
8 explanation of how a renewable solar QF resource is not entitled to the utility’s full
9 capacity value for all peak hours because it is only contributing to a utility’s peak
10 demands part of the time. Obsidian even stated in their Motion that they understood
11 and agreed that Staff’s approach of discounting the Capacity Adder was appropriate
12 for an intermittent resource. The problem, as Obsidian claimed, was that Staff showed
13 that the reduced Capacity Adder would only be paid for those peak hours during which
14 the renewable solar QF was actually generating and delivering energy to the host
15 utility. Obsidian, which ironically has not filed any testimony on this topic in Phase II
16 of this docket, claimed at that time that a renewable solar QF resource should be
17 entitled to the reduced Capacity Adder for all peak hours, including the hours it did not
18 generate.

19 **Q. Do you agree with Obsidian’s claim?**

20 A. No. First of all, I disagree with the use of the word “entitled” and the concept of an
21 entitlement, something which seems to be prevalent in the views of the
22 Staff/Intervenors today. I will discuss this issue later in my testimony. I do agree that
23 a renewable QF solar resource should be paid the avoided cost price, including the
24 Capacity Adder, for all peak hours. However, I believe that they should be paid only
25 for all peak hours during which the project was actually generating and delivering
26 energy to the host utility. To pay for generation that is not generated, or for capacity

1 that is not provided, is absurd and contrary to the FERC definition of avoided cost.

2 The utility's customers are ultimately harmed.

3 **Q. What is the FERC definition of avoided cost you are referring to?**

4 A. I am referring to the definition of avoided cost found in federal regulations, 18 C.F.R.
5 § 292.101(b)(6).

6 **Q. How do the federal regulations define avoided cost for purposes of PURPA QFs?**

7 A. The federal regulations define avoided cost as: "Avoided costs means the incremental
8 costs to an electric utility of electric energy or capacity or both which, but for the
9 purchase from the qualifying facility or qualifying facilities, such utility would generate
10 itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). It is the "but for"
11 portion of the definition that is crucial to Idaho Power's opposition to Obsidian's claim
12 that they should be paid for all peak hours, even when they cannot generate. If the
13 avoided costs are the incremental costs to the utility *but for* the purchase from the QF,
14 then if the utility must still generate or purchase from another resource in order to serve
15 the load while paying the QF for generation it did not provide, the additional cost paid
16 to the QF and recovered from the utility's customers is above and beyond the
17 incremental cost of providing the resource needed to meet load. If the utility has to
18 pay for the generation or purchased power costs to meet load *and* pay for the
19 undelivered capacity of the QF, the customer incurs higher costs and is not held
20 harmless, as PURPA regulation requires.

21 **Q. Was the concept of only paying for the QF generation they actually generated a
22 new concept that resulted from Commission Order No. 14-058?**

23 A. No. In fact, that "second discount" as Obsidian referred to it, has been a part of the
24 Oregon proxy methodology for many years, prior to Order No. 14-058. All QFs were
25 paid the same avoided cost rate for all hours they generated, regardless of QF
26 resource type. The issue being addressed by Order No. 14-058 was that varying types

1 of QF resources actually provided different value to the utility, depending on their
2 operational aspects. Simply stated, solar QFs provide more value than wind QFs in
3 meeting the utility's peak load, yet both were being compensated equally for their
4 generation during the on-peak hours. Additionally, neither intermittent QF resource
5 provided the same value to the utility as the CCCT proxy because they could not be
6 dispatched and did not have the same capacity factor during the on-peak period.
7 While Idaho Power maintains that the proxy methodology is not an accurate reflection
8 of the utility's true avoided cost, the proxy avoided cost calculation prior to Order No.
9 14-058 *did* differentiate between the value a QF resource provided from the value of
10 the proxy CCCT in that the methodology for determining the avoided cost rate paid the
11 full avoided capacity rate, but only during the times the QF generated. Obsidian's
12 claimed "second discount" was not something new that resulted from Order No. 14-
13 058, it was something that was a part of the calculation previously, and an inherent
14 part of the proxy resource methodology. What the modification in Order No. 14-058
15 did was to differentiate between the differing QF resources, providing additional value
16 to solar QFs as compared to wind QFs because of the operational characteristics of
17 those different resource types. But it was never intended to increase the avoided cost
18 paid to the QF above the avoided cost of the CCCT proxy resource. To do so would
19 be harmful to the utility's customers and illegal.

20 **Q. You stated previously that the "concept of an entitlement" seemed to be**
21 **prevalent in the testimony of the Staff/Intervenors today. Would you please**
22 **describe further what brings you to this conclusion?**

23 A. Certainly. The parties discuss an outdated concept that a QF is entitled to a fixed
24 amount capacity payment, regardless of when it generates. Idaho Power does not
25 agree with this concept and the Commission has not authorized or directed this
26 practice. There are specific examples of the language used in testimony that leads

1 me to believe there is a sense of entitlement. For example, OneEnergy Witness Bill
2 Eddie states that “the capacity adder for solar QFs accepting the renewable avoided
3 cost rates is *intended to pay solar QFs a certain amount of money...*” (Emphasis
4 added). And later on the same page, as Mr. Eddie describes how the current Oregon
5 methodology spreads the actual payment of Capacity Dollars to QFs over all on-peak
6 hours, Mr. Eddie states “In other words, to get the full amount of “Capacity Dollars” *it*
7 *is owed*, a solar project would need to perform as well at 7:00 AM on a cool, cloudy
8 April morning as it does on a hot sunny July afternoon.” (Emphasis added)
9 OneEnergy/400, Eddie/6-7.

10 Staff Witness Andrus states that using the traditional dollars-per-kWh capacity
11 payment rate, which is based on the availability of a baseload resource during on-peak
12 hours (the proxy CCCT resource) as the starting point for a capacity-contribution
13 adjustment “means that any resource that *does not operate as a baseload resource*
14 *will not receive payment reflective of the QF’s capacity contribution, but will receive*
15 *only a fraction of such payments.*” (emphasis added) Staff/500, Andrus/17.

16 And finally, ODOE Witness Broad states that because the volumetric price
17 spreads the cost of capacity over a number of MWh as if the QF’s on-peak capacity
18 factor is equivalent to that of a CCCT, “*it is impossible for an intermittent resource that*
19 *cannot operate in all those hours to receive all of the capacity dollars to which it is*
20 *entitled.*” (emphasis added) ODOE/800, Broad/5-6. This sense of entitlement to a
21 “pool of dollars” regardless of whether a QF actually provides capacity or when a QF
22 generates is prevalent within the testimonies of the Staff/Intervenors today, and has
23 helped entrench the views of each side. I believe PacifiCorp Witness Dickman
24 accurately summarizes the issue of changing the calculation of capacity costs inherent
25 in Issues 3 and 4 when he states that it “boils down to whether the fixed cost of the
26 CCCT should be spread across on-peak hours and only paid to a QF when it is

1 generating (as has been done for many years), or whether a QF should be paid a fixed
2 amount for capacity regardless of when it generates.” PAC/800, Dickman/10. Idaho
3 Power does not believe that there is a “pool of money” that QFs are entitled to receive,
4 regardless of when they generate. PURPA regulation states that the dollars that are
5 paid to QF developers as avoided costs are the incremental costs to an electric utility
6 of electric energy or capacity or both which, but for the purchase from the qualifying
7 facility, the utility would generate itself or purchase from another source.

8 **Q. Does ODOE believe that the revised method proposed by Staff and supported**
9 **by the Intervenor is already being used by Idaho Power?**

10 A. Yes they do, but they have only provided a part of the story. ODOE describes in part,
11 the methodology that Idaho Power uses for negotiated QF rates for QF developers
12 above the eligibility cap. Until recently, the eligibility cap for standard rates for all QF
13 projects in Oregon was 10 MW. Commission Order No. 15-199 recently reduced, on
14 an interim basis and effective April 24, 2015, the eligibility cap to 3 MW for standard
15 contracts offered by Idaho Power to solar QF projects. In Idaho Power’s Idaho
16 jurisdiction, the eligibility cap for standard rates is 100 kW for wind and solar QFs and
17 10 average MW for all other resource types.

18 **Q. How has ODOE only provided a part of the story in their description of the**
19 **methodology used for negotiated rates for Idaho Power?**

20 A. ODOE only shares one portion of the Incremental Cost IRP (“ICIRP”) methodology
21 and states that by “customizing the rate to each QF, this method accurately represents
22 actual avoided capacity costs.” ODOE then concludes that for standard rates, “it is
23 reasonable to use the characteristics of a proxy QF resource type.” ODOE/800,
24 Broad/10. This is an inaccurate conclusion.

25 In my Direct Testimony filed November 4, 2014, I outlined at a high level the
26 ICIRP methodology. The ICIRP methodology determines the avoided cost for each

1 QF project greater than the eligibility cap by determining three cost components: (1)
2 the avoided cost of energy, (2) the avoided cost of capacity, and (3) the applicable
3 integration costs. These three cost components, when added together, create a
4 unique monthly heavy and light load avoided cost price for each QF project.

5 ODOE has only described one portion of the methodology, and then uses that
6 to support its conclusion that it should be the same for the proxy method. While no
7 methodology is perfect in determining a utility's actual avoided costs, Idaho Power
8 continues to maintain that a more accurate determination of actual avoided costs is
9 the ICIRP. That method attempts to determine the cost of the resource being avoided
10 in every hour of every day throughout the contract term. If a utility is in a resource
11 sufficient period, the avoided cost of capacity portion of the payment is not included.
12 And in Idaho, the additional refinement of the resource sufficiency period is
13 implemented with the addition of each QF resource. The ICIRP methodology is much
14 more sophisticated in its approach to the determination of the avoided cost. ODOE's
15 conclusion that because a portion of the calculation of the avoided cost is included in
16 the more refined ICIRP methodology, it is then "reasonable to use" in determining the
17 avoided cost through the Oregon proxy method is just wrong and misleading. The
18 proxy methodology is based upon the fiction/assumption that the utility avoids the cost
19 associated with a CCCT, and assigns an avoided cost based upon the cost of that
20 assumed CCCT. To the contrary, the ICIRP methodology calculates the utility's
21 avoided cost specific to a particular proposed QF project, based upon the project's
22 specific hourly generation forecast/profile. The ICIRP methodology compares the
23 project's generation profile to the utility's resource stack being used to serve load in
24 each hour and assigns the cost of the utility's highest cost displaceable resource
25 operating during the hours that the QF provides generation. This is accumulated into
26 monthly heavy and light load pricing. The Oregon proxy method is intended to be a

1 simplified, transparent calculation, but does not capture all of the impacts of individual
2 QFs on the Company's system. PacifiCorp Witness Dickman summarized with the
3 following: "Fixing the capacity adder dollars paid to a QF implies that the QF can fully
4 replace some portion of a CCCT, but does not recognize the benefits lost when a
5 CCCT is replaced by a QF. Unless the full impact of adding a QF to a utility's system
6 are accounted for, fixing the dollars paid for capacity inflates avoided cost prices and
7 moves further away from avoided costs rather than closer." PAC/800, Dickman/11.

8 **Q. With regard to Issues 3 and 4, should the Commission revise the methodology**
9 **approved in Order No. 14-058 for determining the capacity contribution**
10 **calculation for both renewable avoided cost prices (Issue 3) and standard non-**
11 **renewable avoided cost prices (Issue 4)?**

12 A. No. As I stated in my Direct Testimony in Phase II of Docket UM 1610, Idaho Power's
13 Schedule 85 currently implements Order No. 14-058 properly by allocating a capacity
14 payment to solar and wind QFs based upon a reduction from 100 percent of the
15 capacity cost of proxy resource to each resource's contribution to peak from the
16 acknowledged IRP, as directed in Order No. 14-058. To pay for generation that is not
17 generated, or for capacity that is not provided, is contrary to the FERC definition of
18 avoided cost. The utility's customers are ultimately harmed. For many years, the
19 Oregon proxy methodology has determined an avoided cost rate that was only paid
20 for those peak hours during which the renewable QF was actually generating and
21 delivering energy to the host utility. What the modification in the approved Order No.
22 14-058 did was to differentiate between the differing QF resources, providing
23 additional value to solar QFs as compared to wind QFs because of the operational
24 characteristics of those different resource types. To modify the methodology now as
25 Staff/Intervenors suggest would increase the avoided cost rate paid to the QF above
26 the avoided cost rate of the proxy resource. As shown in my direct testimony, as well

1 as the previous testimony and briefing on this issue from Idaho Power, the proposed
2 changes actually result in compensating a solar QF for capacity at a higher rate than
3 the 100% capacity proxy CCCT. This not is logically incorrect; it is harmful to the
4 utility's customers and illegal. The current methodology approved in Order No. 14-058
5 should be affirmed by the Commission in this proceeding and Staff/Intervenor
6 proposals rejected as requiring payment in excess of avoided costs.

7 **Q. With regard to Issue 6, do market prices used during the Resource Sufficiency**
8 **Period sufficiently compensate for capacity?**

9 A. Yes, and in fact, may over-compensate the QF provider.

10 **Q. What do you mean that market prices used during a period of Resource**
11 **Sufficiency may over-compensate a QF provider?**

12 A. As I stated in my Direct Testimony, it should be noted that this Commission has long
13 differentiated between the calculations of avoided costs for a utility in a resource deficit
14 position from a utility in a surplus position. In Order No. 05-584, issued in Docket No.
15 UM 1129, the Commission adopted Staff's recommendation that QF capacity be
16 valued based on the market and adopted the methodology that values avoided costs
17 when a utility is in a resource sufficient position at monthly on- and off-peak forward
18 market prices as of the utility's avoided cost filing. Order No. 05-584, p. 28. However,
19 not all commissions maintain the same view. In Idaho Power's Idaho jurisdiction, the
20 Idaho Public Utilities Commission in Order No. 32697, page 21, when discussing a
21 utility's payment to a QF for capacity, stated:

22 In calculating a QF's ability to contribute to a utility's need for
23 capacity, we find it reasonable for the utilities to only begin
24 payments for capacity at such time that the utility becomes
25 capacity deficient. If a utility is capacity surplus, then capacity is
26 not being avoided by the purchase of QF power. By including a
capacity payment only when the utility becomes capacity
deficient, the utilities are paying rates that are a more accurate
reflection of a true avoided cost for the QF power.

1 In the Company's Idaho jurisdiction, the capacity portion of the payment is included
2 only when the utility is capacity deficient. In the Company's Oregon jurisdiction, under
3 the Standard Proxy Method, the QF is paid an on-peak and off-peak market price
4 based upon a forward price curve determined at the time of the Company's avoided
5 cost filing. The on-peak price embeds the value of incremental QF capacity in the total
6 market-based avoided rate, and therefore, the QF is receiving compensation for
7 capacity even when the utility is Resource Sufficient.

8 **Q. Is it fair to compensate a QF for capacity during the time of a utility's resource**
9 **sufficiency?**

10 A. A better question may be: "Is it fair to the customer to pay for capacity during the time
11 of resource sufficiency and additional capacity is not needed? If a utility is capacity
12 surplus, the capacity is not being avoided by the purchase of QF power; therefore, the
13 utility and its customers are not avoiding any capacity costs during that time. The
14 avoided cost rates in Idaho Power's Idaho jurisdiction do not include a capacity
15 payment during a period of resource sufficiency. However, in Oregon, they are
16 compensated, even though it is not a cost being avoided by the utility.

17 **Q. What are the positions of the parties with regard to this issue?**

18 A. PGE states that no additional payment for capacity is warranted during the sufficiency
19 period, and that "a capacity payment during the sufficiency period results in prices that
20 exceed the avoided cost of the utility." PGE/500 Macfarlane/9.

21 PacifiCorp affirms that using market prices during the sufficiency period
22 sufficiently compensates QFs for capacity, stating the "market prices generally
23 represent the incremental cost of energy and capacity used to balance the Company's
24 system prior to procuring its next major resource." PAC/800 Dickman/14. Staff is in
25 agreement, and adds their view that "the relationship between the utilities' capacity
26 needs during sufficiency periods and the prices for capacity paid to the QFs is sufficient

1 to comply with PURPA.” Staff/500 Andrus/30. Idaho Power would argue that payment
2 for capacity during a period of resource sufficiency does not comply with FERC’s
3 definition of avoided cost as there are no incremental costs of capacity that are being
4 avoided. While paying market prices for capacity may sufficiently compensate a QF
5 project for capacity, if a utility is resource sufficient, it does not need any additional
6 capacity. Paying any amount for capacity during a utility’s Resource Sufficient Period,
7 is an additional cost above the costs being avoided, and is harmful to the customers.

8 **Q. What are the positions of the Intervenor with regard to this issue?**

9 A. ODOE makes a brief statement saying that it depends on how market prices are
10 forecast and whether that forecast accurately reflects the actual purchasing practices
11 of a utility. It is ironic that ODOE is concerned whether or not a market price forecast
12 reflects the *actual* practices of a utility, in light of their testimony on Issues 3 and 4
13 requesting a change in the methodology approved in Order No. 14-058 regarding how
14 the capacity contribution is calculated stating “it is impossible for an intermittent
15 resource that cannot operate in all those hours to receive all of the capacity dollars to
16 which it is entitled.” ODOE/800 Broad/5-6.

17 Not surprisingly, the remaining Intervenor do not believe that receiving market
18 prices during the period of a utility’s resource sufficiency is sufficient compensation.
19 Jointly, they sponsored the testimony of Kevin C. Higgins. His recommendation is
20 limited just to PacifiCorp because, as Mr. Higgins claims, of its extraordinarily extended
21 sufficiency period. Nevertheless, Idaho Power offers a couple of comments on Mr.
22 Higgins’ testimony.

23 Mr. Higgins suggests requiring the development of an Alternative IRP scenario
24 that re-determined the preferred resource portfolio absent the (assumed) renewing
25 QFs in order to properly value the capacity that QFs would avoid. Joint QF Parties/100
26 Higgins/4-5. He also discusses at great length the uncertainty surrounding compliance

1 with the Environmental Protection Agency (“EPA”) under the proposed Section 111(d)
2 rules of the Clean Air Act. Mr. Higgins recommends that the Commission adopt an
3 interim capacity pricing mechanism for PacifiCorp’s Schedule 37.

4 **Q. What is Idaho Power’s response to Mr. Higgins recommendations?**

5 A. With regard to the Commission adopting an interim capacity pricing mechanism for
6 PacifiCorp’s Schedule 37, Idaho Power believes this is not relevant under federal
7 regulations for PURPA. The utilities’ responses to proposed requirements under
8 Section 111(d) are unknown at this time, and therefore, cannot constitute any real cost
9 avoidance with any certainty. It is premature to impose additional costs as part of the
10 avoided cost determination for legislation that is not yet final. To do so would mean
11 that customers are paying for something that is not yet being avoided.

12 With regard for the determination of the value of capacity for QF contracts that
13 are currently a part of a utility’s IRP and will expire, but plan to renegotiate a new QF
14 contract with the utility, REC offers another solution in place of the Alternative IRP
15 scenario Mr. Higgins recommends. REC recommends that the better and more
16 accurate fix for existing QFs would be to adopt the same solution as the Idaho Public
17 Utilities Commission has done, paying existing QFs for capacity during the resource
18 sufficiency period.

19 **Q: Has the Commission given any recent direction regarding the implementation
20 of solar integration charges?**

21 A. Yes. In response to Idaho Power’s motion for a temporary stay of its PURPA purchase
22 obligation in UM 1725, the Commission issued Order No. 15-199 on June 23, 2015.
23 With this order the Commission denied Idaho Power’s request for a temporary stay,
24 but determined to grant the interim relief of reducing the standard rate eligibility cap
25 for solar projects from 10 MW to 3 MW. The Commission also stated,
26

1 Further, given the rapid growth in solar QF activity, we believe
2 it is time to address solar integration charges. We direct parties
3 to address in docket UM 1610 the level of solar integration
charges to incorporate into avoided cost rates.

4 Order No. 15-199, p. 7. Subsequently, Idaho Power filed a motion for clarification of
5 the Commission's order, and with regard to the above quoted statement about solar
6 integration asked the Commission to clarify that it did not intend to defer or delay
7 consideration of Idaho Power's pending application for approval of solar integration
8 charges in UM 1725.

9 The parties to this docket, UM 1610, previously executed and filed with the
10 Commission a Stipulation regarding the Issues List, as well as a corresponding
11 Stipulation addressing and resolving several substantive issues in the case. In that
12 Stipulation regarding the Issue List the parties agreed that solar integration charges,
13 and several other issues not be included in UM 1610, but recognized that Idaho Power
14 would bring those issues, including solar integration, before the Commission as
15 separate filings.

16 Notwithstanding anything stated and agreed to in this
17 Stipulation, as well as the accompanying Stipulation referenced
18 in paragraphs B. above, Idaho Power hereby reserves the right
19 to bring as separate case filings matters related to: (1) revision
20 of the standard rate eligibility cap; (2) the appropriate maximum
21 contract term;; (3) implementation of solar integrations charges;
22 and (4) revision of Idaho Power's resource sufficiency period.
The parties have agreed that these matters not be included in
the proceedings for UM 1610, and further agree and understand
that removing these Idaho Power issues from UM 1610 should
not prejudice any right of Idaho Power to bring these matters
before the Commission as Idaho Power specific case filings.

23 Subsequently, on April 24, 2015, Idaho Power filed three separate applications
24 requesting that the Commission (1) lower the standard contract eligibility cap for wind
25 and solar QFs to 100 kilowatts and reduce the term of wind and solar QF contracts to
26 2 years; (2) approve a solar integration charge; and (3) modify the Company's

1 resource sufficiency period. All three applications were docketed under UM 1725 by
2 the Commission, and are currently set for hearing on October 21, 22, and 23, 2015.
3 The Commission has not yet ruled upon Idaho Power's request for clarification, and
4 Idaho Power is unsure of the Commission's intent with regard to its statement to
5 parties to "address in docket UM 1610 the level of solar integration charges to
6 incorporate into avoided cost rates." At any event, Idaho Power has filed an
7 application and direct testimony as well as its 2014 Solar Integration Study Report
8 seeking the implementation of solar integration charges. To the extent that the
9 Commission desires party positions regarding solar integration to be submitted in UM
10 1610, Idaho Power hereby incorporates the application, testimony, and supporting
11 documents submitted in UM 1725 requesting the implementation of solar integration
12 charges for Idaho Power.

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

14 A. Yes, it does.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1610
PHASE II

In the Matter of)
)
PUBLIC UTILITY COMMISSION OF)
OREGON)
)
Investigation into Qualifying Facility)
Contracting and Pricing.)
_____)

IDAHO POWER COMPANY
RESPONSE TESTIMONY
OF
RANDY ALLPHIN

July 24, 2015

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

2 A. My name is Randy Allphin. My business address is 1221 West Idaho Street, Boise,
3 Idaho 83702.

4 **Q. Are you the same Randy Allphin who previously testified in this docket?**

5 A. Yes. My witness qualifications are set forth in my Direct Testimony, Idaho Power/900.

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

7 A. The purpose of my testimony is to address, on behalf of Idaho Power, several of the
8 issues identified in the UM 1610 Phase II Issues List. There are nine designated
9 issues on the Issues List. Mr. Youngblood provides testimony on behalf of Idaho
10 Power relevant to issue numbers 3, 4, and 6 and addresses the Public Utility
11 Commission of Oregon's ("Commission") direction regarding solar integration. I
12 provide testimony relevant to the remaining six issues, Issue List items numbers 1, 2,
13 5, 7, 8, and 9. As noted, I previously filed direct testimony relevant to Idaho Power's
14 position on several issues and now provide this testimony in response to the direct
15 testimony filed May 22, 2015, in Phase II of Docket No. UM 1610 by many of the other
16 parties to this docket including: the direct testimonies of Commission Staff, Oregon
17 Department of Energy ("ODOE"), the Renewable Energy Coalition ("REC" or
18 "Coalition"), Community Renewable Energy Association ("CREA"), OneEnergy,
19 Obsidian Renewables, LLC ("Obsidian"), and Gardner Capital Solar Development,
20 LLC ("Gardner Capital"), collectively referred to as the Intervenors, as well as the other
21 two utilities, Portland General Electric ("PGE") and PacifiCorp d/b/a Pacific Power
22 ("PacifiCorp") regarding the Issue List items numbers 1,2,5,7,8 and 9. I will also
23 address comments made by the other two utilities, PGE and PacifiCorp.

24 **Q. Please list the issues addressed by your Testimony.**

25 A. I provide testimony relevant to the following six issues:
26

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

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

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

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

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

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

13 **Q. Please summarize your response testimony.**

14 A. As stated in my direct testimony, Idaho Power agrees with the Commission's current
15 policies on many of the issues, and differs from the Commission's current policies on
16 others. Upon review of the parties' direct testimony, Idaho Power's position on the
17 issues remains unchanged. However, given the procedure of simultaneous filing of
18 direct testimony by all parties, many of the parties have not directly addressed Idaho
19 Power's positions. Consequently, rather than unduly repeating the Company's
20 positions, statements, and rationale, Idaho Power will rely upon the position set forth
21 by its direct testimony and reserve the right to further address these issues in reply,
22 and/or rebuttal testimony.

23 **Q. What is Idaho Power's response to testimony provided regarding Issue 1: Who**
24 **owns the Green Tags during the last five years of a 20-year fixed price PPA**
25 **during which prices paid to the QF are at market?**

26

1 A. As I stated in my direct testimony, with no present renewable portfolio requirement
2 under state or federal law, Idaho Power does not have renewable avoided cost rates.
3 Instead, the Company has only non-renewable standard and negotiated avoided cost
4 rates in the state of Oregon, for which the Commission has previously determined that
5 the Green Tags or Renewable Energy Credits/Certificates (RECs) are owned by the
6 QF. While Idaho Power is not contesting this policy, I will provide a comment. Under
7 Idaho Power's currently-approved REC management plan, the Company is required
8 to sell its RECs on a short term basis and return the proceeds to Idaho Power
9 customers, which it does through the annual power cost adjustment mechanisms in
10 Idaho and Oregon. The Company expects that if the Commission were to determine
11 that Idaho Power owned RECs in the last five years of a PURPA QF contract when
12 market prices are in place, Idaho Power would similarly sell the RECs, benefiting Idaho
13 Power's customers by applying the net proceeds as a credit to the Annual Power
14 Supply Expense True-up Balancing Account as part of the Power Cost Adjustment
15 Mechanism ("PCAM"), as directed by Order No. 11-086.

16 **Q. What is Idaho Power's response to testimony provided regarding Issue 2:
17 Should avoided transmission costs for non-renewable and renewable proxy
18 resources be included in the calculation of avoided cost prices?**

19 A. As noted by Staff, this issue is included in this docket largely in relation to questions
20 about PacifiCorp and the use of third-party transmission costs for a proxy resource,
21 particularly if the proxy resource for PacifiCorp's renewable avoided cost rates is a
22 Wyoming wind resource. Staff/500 Andrus/7, 9. Idaho Power does not have
23 renewable avoided cost rates, and as stated in my direct testimony, Idaho Power's
24 proxy resource is and/or is assumed to be located on-system as a designated network
25 resource available to serve load. Similar to the Commission's prior determination for
26 third-party transmission costs, there is no additional avoided transmission expense for

1 a designated network resource proxy generation plant, and there should be no change
2 to current calculations of avoided cost rates as a result.

3 **Q. What is Idaho Power's response to testimony provided regarding Issue 5: What**
4 **is the appropriate forum to resolve litigated issues and assumptions?**

5 A. Idaho Power maintains that the appropriate forum to resolve litigated issues and
6 assumptions related to Public Utility Regulatory Policies Act of 1978 ("PURPA") in
7 general, and avoided costs in particular, is in a Commission docket specifically opened
8 to resolve such litigated issues and/or assumptions—either at the request of the utility,
9 Staff, or any other party. The appropriate place to resolve litigated PURPA issues and
10 assumptions is *not* the utility's IRP proceeding, or the avoided cost compliance filing.
11 Neither of these types of dockets are set up as contested cases, and past attempts to
12 use these dockets to litigate avoided cost inputs have resulted in confusion and delay.

13 For compliance filing purposes, it is important to distinguish, between situations
14 where the Commission has previously determined, during the course of a contested
15 proceeding, that the utility should use a value obtained from the utility's IRP for an
16 avoided cost input or purpose, and a situation where the Commission has not made
17 such determination, but the utility utilizes a value from its IRP for an avoided cost input.
18 Where the Commission has specifically directed the utility to use an input derived from
19 the IRP, the only question for the compliance filing is whether the utility utilized the
20 input identified by the IRP. The compliance filing should not be viewed as an
21 opportunity to contest the use of that input—that opportunity was available to the
22 parties during the course of the Commission's PURPA proceeding in which it ordered
23 the utility use a value or input from the IRP for purposes of avoided cost calculations,
24 or for whatever purpose that value is intended. Even if the Commission has *not*
25 directed the utility to use a specific input from the IRP, parties should not be allowed
26 to challenge such input in a compliance filing. Rather, if a party has an issue with a

1 particular input, methodology, or practice with regard to avoided cost rates or the
2 implementation of the utility's PURPA obligations, then those issues should be brought
3 to the Commission through an application, petition, complaint, or investigation where
4 the Commission can properly consider the issue through a contested proceeding.

5 **Q. What is Idaho Power's response to testimony provided regarding Issue 7: What**
6 **is the most appropriate methodology for calculating non-standard avoided cost**
7 **prices? Should the methodology be the same for all three electric utilities**
8 **operating in Oregon?**

9 A. As Staff correctly notes, "Idaho Power is allowed to use the modeling methodology
10 authorized by the Idaho Public Utilities Commission, with some additional
11 requirements imposed by this Commission, as the starting point for negotiations with
12 QFs seeking non-standard rates." Staff/500 Andrus/35.

13 However, CREA's direct testimony mischaracterizes the Commission's Order
14 No. 07-360. CREA states that the Commission determined that PacifiCorp and PGE
15 should use the standard avoided costs as a starting point, while it "allowed Idaho
16 Power to use the computer modeling methodology *in place at that time* under the Idaho
17 Public Utilities Commission's implementation of PURPA." (emphasis added)
18 CREA/500 Skeahan/17. That is not what the order stated. Order No. 07-360,
19 Appendix A, "Adopted Guidelines for Negotiation of Power Purchase Agreements for
20 QFs 10 MW or Larger" states:

21 For Idaho Power, the starting point for negotiations are the
22 avoided costs calculated under the modeling methodology
23 approved by the Idaho Public Utilities Commission for QFs over
24 10 MW, as refined by the Oregon Commission to incorporate
stochastic analyses of electric and natural gas prices, loads,
hydro and unplanned outages.

25 Recently, the Commission reaffirmed this practice when it issued Order No. 15-199 on
26 June 23, 2015, Docket No. UM 1725. In that order, the Commission stated:

1 We conclude that this unprecedented pace and volume of QF
2 development justifies interim relief in order to prevent harm to
3 Idaho Power's ratepayers. We further conclude that such relief
4 should be narrow, targeted, and proportionate. To that end, we
5 adopt REC's suggestion and reduce the eligibility cap for Idaho
6 Power's standard contracts to 3 MW for solar QF projects. The
effect of this relief is that projects greater than 3 MW in size will
fall under our large QF policies, where contracts are negotiated
between the developer and the utility pursuant to Commission-
approved guidelines set forth in Idaho Power's Schedule 85.

7 Idaho Power's Schedule 85 contains the same language from Appendix A stated
8 above.

9 **Q. In summary, what is the methodology proposed by Idaho Power for calculating**
10 **non-standard avoided cost prices?**

11 A. As I stated in my direct testimony, Idaho Power is not requesting any change to the
12 current methodology authorized by the Commission for calculating non-standard
13 avoided cost prices. In addition, Idaho Power does not believe that all three utilities
14 need to use the same methodology. Idaho Power's currently-approved methodology
15 for avoided cost rates for those QF projects that exceed the standard rate eligibility
16 cap is the incremental cost IRP methodology ("ICIRP"). This methodology has been
17 in place for Idaho Power since approved for use through a contested case proceeding
18 before the Idaho Public Utilities Commission in December 2012. IPUC Order No.
19 32697, Case No. GNR-E-11-03. As stated in my direct testimony, Idaho Power is not
20 proposing changes to this methodology as it is currently implemented in its Idaho
21 jurisdiction.

22 The ICIRP methodology results in a project-specific avoided cost calculation
23 that precisely matches the Federal Energy Regulatory Commission's ("FERC")
24 definition of avoided cost. "Avoided cost means the incremental costs to an electric
25 utility of electric energy or capacity or both which, but for the purchase from the
26 qualifying facility or qualifying facilities, such utility would generate itself or purchase

1 from another source.” 18 CFR § 292.101(b)(6). The methodology compares the
2 project’s specific hourly generation profile to the utility’s resource stack being used to
3 serve load in each hour, and assigns the cost of the utility’s highest cost displaceable
4 resource operating during the hours that the QF provides generation, as the avoided
5 cost. The capacity component of the rate is based upon the generation resource type
6 and the avoided cost of a simple-cycle combustion turbine and added to the energy
7 component derived from the utility’s hourly highest cost displaceable resources. The
8 hourly values are accumulated into monthly heavy and light load pricing.

9 Recently, this modeling methodology has been used to provide indicative
10 pricing for more than 40 separate solar QF projects comprising over 1,000 MW of
11 nameplate capacity. This includes executed PURPA QF solar contracts for more than
12 400 MW in the Company’s Idaho jurisdiction. In fact the Company is presently
13 providing, or has provided indicative pricing using the ICIRP methodology to an
14 additional 14 solar QF projects with a combined nameplate in excess of an additional
15 100 MW, all in the state of Oregon, and anticipates additional executed contracts very
16 soon with several of these projects under this pricing.

17 Idaho Power proposes no changes to the methodology and process that has
18 been in place since 2012 for calculating non-standard avoided cost prices, and no
19 changes to the Commission’s current authorized avoided cost rate determinate for
20 projects over the standard rate eligibility cap for Idaho Power as stated in Schedule
21 85:

22 For Idaho Power, the starting point for negotiations are the
23 avoided costs calculated under the modeling methodology
24 approved by the Idaho Public Utilities Commission for QFs over
25 10 MW, as refined by the Oregon Commission to incorporate
26 stochastic analyses of electric and natural gas prices, loads,
hydro and unplanned outages.

1 **Q. What is Idaho Power’s response to testimony provided regarding Issue 8: When**
2 **is there a legally enforceable obligation?**

3 A. As stated in my direct testimony, this is largely a legal issue that Idaho Power intends
4 to address through legal briefing. I am not an attorney and thus I offered the
5 Company’s position on legally enforceable obligation from my perspective as the
6 Company’s PURPA Energy Contracts Coordinator Leader. My direct testimony
7 contains a relatively thorough discussion of the concepts involved, and I stand by those
8 statements in this response. I do note however, that several parties, including Staff
9 have properly focused upon the correct principle—that a legally enforceable obligation
10 is a largely factual, case-by-case determination that is within the Commission’s
11 authority and discretion to determine. To simplify, a QF can create a legally
12 enforceable obligation from the utility and its customers by obligating itself to the
13 transaction. Idaho Power agrees with Staff that there must be a *real* obligation on the
14 part of the QF in order to incur a legally enforceable obligation with the utility and its
15 customers.

16 Gardner Capital provides testimony largely limited to addressing this issue with
17 Idaho Power. Idaho Power notes that Gardner Capital has a separately-filed complaint
18 proceeding pending before the Commission to resolve its issues regarding legally
19 enforceable obligation pertaining to its initial requests for draft contracts, Docket UM
20 1733, and that its particular, fact-based issues are more appropriately addressed in
21 that docket. However, I had summarized one of Commission’s few cases directly
22 applying its rules regarding legally enforceable obligation in my direct testimony that
23 is particularly relevant to Gardner Capital’s arguments.

24 In Order No. 09-439 in Docket UM 1449, a QF larger than 10
25 megawatts was in the process of negotiating a power purchase
26 agreement (“PPA”) with PacifiCorp when PacifiCorp filed to
update its avoided cost prices. After the Commission approved
PacifiCorp’s new prices, the QF filed a complaint requesting that

1 the Commission require PacifiCorp to execute a PPA with the
2 QF that included the previous avoided cost prices in effect
3 during negotiations. In granting PacifiCorp's motion to dismiss
4 the QF's complaint, the Commission found that under OAR 860-
5 029-0010(29)(b) a legally enforceable obligation was not
6 created simply by PacifiCorp's provision of a draft PPA to the
7 QF. The Commission noted that conventional contract law does
8 not apply to QF transactions because they are creatures of
9 statutes and the Commission's rules. Therefore, acceptance of
10 the terms of the draft contract does not constitute an agreement
11 and because the draft contract was not a binding written
12 agreement between the parties, PacifiCorp had not incurred a
13 legally binding obligation.

14 Idaho Power/900 Allphin/11.

15 Gardner and other parties argue that a QF can create a "legally enforceable
16 obligation" requiring the utility and its customers to pay a previously-effective avoided
17 cost rates—and one that happens to be much higher than currently-effective rates—
18 on initial requests for draft contracts or other first contacts. This position is completely
19 without merit and in fact could cause substantial harm to Idaho Power customers by
20 locking in a long-term, fixed price rate that we know is an inflated and inaccurate
21 estimation of the utility's actual avoided cost. Gardner, upon its first contact requesting
22 a draft contract has made no commitment, and has not bound itself to any obligation
23 to the utility and its customers. Idaho Power acted in compliance with its procedural
24 obligations under Schedule 85, and responded to Gardner's initial request within 15
25 days. Idaho Power also acted well within its rights and responsibilities to protect its
26 customers by bringing significant matters related to the proper avoided cost rates to
the Commission for resolution prior to incurring any further legally enforceable
obligations that would be extremely harmful to its customers.

27 **Q. What is Idaho Power's response to testimony provided regarding Issue 9: How
28 should third-party transmission costs to move QF output in a load pocket to
29 load be calculated and accounted for in the standard contract?**

1 A. Once again, just as with Issue 2 above, this Issue 9 stems largely from operational
2 aspects relevant to PacifiCorp's system. Recognizing, as stated in direct testimony,
3 that the Commission has previously found that costs associated with third-party
4 transmission to move QF output in a load pocket to load must be assigned to the QF
5 in order to comport with PURPA avoided cost principles, Staff recommends "that in
6 cases for which the utility proposes the assignment of third party transmission costs,
7 the utility be required to provide specific and detailed information regarding the load,
8 generation, and transmission capacity values used in making that determination, and
9 into the basis for calculating the amount and cost of the third party transmission that
10 would be required." Staff/500 Andrus/42. Idaho Power generally agrees with Staff's
11 recommendation, and reiterates that this cost be allocated to the QF separately from
12 the purchase contract as part of the interconnection and network resource designation
13 process. Idaho Power does not have any existing or proposed QF projects that would
14 require the use of third-party transmission to move the QF generation from a load
15 pocket to load. However, if the Company did have such a situation, it believes that,
16 under existing processes, Idaho Power's load serving operations could adequately
17 assess the third-party transmission cost to the QF through the process of
18 interconnection and network resource designation of the QF.

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

20 A. Yes, it does.
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