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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,

Wendy McIndoo

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

Q. Please state your name and business address.

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

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

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

Q. What is the purpose of your testimony?

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

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

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

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

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

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

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

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

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

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

Q. Do you agree with Obsidian's claim?

A. No. First of all, I disagree with the use of the word "entitled" and the concept of an entitlement, something which seems to be prevalent in the views of the Staff/Intervenors today. I will discuss this issue later in my testimony. I do agree that a renewable QF solar resource should be paid the avoided cost price, including the Capacity Adder, for all peak hours. However, I believe that they should be paid only for all peak hours during which the project was actually generating and delivering energy to the host utility. To pay for generation that is not generated, or for capacity that is not provided, is absurd and contrary to the FERC definition of avoided cost. The utility's customers are ultimately harmed.

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

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

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

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

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

A. No. In fact, that "second discount" as Obsidian referred to it, has been a part of the Oregon proxy methodology for many years, prior to Order No. 14-058. All QFs were paid the same avoided cost rate for all hours they generated, regardless of QF resource type. The issue being addressed by Order No. 14-058 was that varying types of QF resources actually provided different value to the utility, depending on their operational aspects. Simply stated, solar QFs provide more value than wind QFs in meeting the utility's peak load, yet both were being compensated equally for their generation during the on-peak hours. Additionally, neither intermittent QF resource provided the same value to the utility as the CCCT proxy because they could not be dispatched and did not have the same capacity factor during the on-peak period. While Idaho Power maintains that the proxy methodology is not an accurate reflection of the utility's true avoided cost, the proxy avoided cost calculation prior to Order No. 14-058 ***did*** differentiate between the value a QF resource provided from the value of the proxy CCCT in that the methodology for determining the avoided cost rate paid the full avoided capacity rate, but only during the times the QF generated. Obsidian's claimed "second discount" was not something new that resulted from Order No. 14-058, it was something that was a part of the calculation previously, and an inherent part of the proxy resource methodology. What the modification in Order No. 14-058 did was to differentiate between the differing QF resources, providing additional value to solar QFs as compared to wind QFs because of the operational characteristics of those different resource types. But it was never intended to increase the avoided cost paid to the QF above the avoided cost of the CCCT proxy resource. To do so would be harmful to the utility's customers and illegal.

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

A. Certainly. The parties discuss an outdated concept that a QF is entitled to a fixed amount capacity payment, regardless of when it generates. Idaho Power does not agree with this concept and the Commission has not authorized or directed this practice. There are specific examples of the language used in testimony that leads me to believe there is a sense of entitlement. For example, OneEnergy Witness Bill Eddie states that "the capacity adder for solar QFs accepting the renewable avoided cost rates is *intended to pay solar QFs a certain amount of money…"* (Emphasis added). And later on the same page, as Mr. Eddie describes how the current Oregon methodology spreads the actual payment of Capacity Dollars to QFs over all on-peak hours, Mr. Eddie states "In other words, to get the full amount of "Capacity Dollars" *it is owed*, a solar project would need to perform as well at 7:00 AM on a cool, cloudy April morning as it does on a hot sunny July afternoon." (Emphasis added) OneEnergy/400, Eddie/6-7.

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

And finally, ODOE Witness Broad states that because the volumetric price spreads the cost of capacity over a number of MWh as if the QF's on-peak capacity factor is equivalent to that of a CCCT, *"it is impossible for an intermittent resource that cannot operate in all those hours to receive all of the capacity dollars to which it is entitled."* (emphasis added) ODOE/800, Broad/5-6. This sense of entitlement to a "pool of dollars" regardless of whether a QF actually provides capacity or when a QF generates is prevalent within the testimonies of the Staff/Intervenors today, and has helped entrench the views of each side. I believe PacifiCorp Witness Dickman accurately summarizes the issue of changing the calculation of capacity costs inherent in Issues 3 and 4 when he states that it "boils down to whether the fixed cost of the CCCT should be spread across on-peak hours and only paid to a QF when it is generating (as has been done for many years), or whether a QF should be paid a fixed amount for capacity regardless of when it generates." PAC/800, Dickman/10. Idaho Power does not believe that there is a "pool of money" that QFs are entitled to receive, regardless of when they generate. PURPA regulation states that the dollars that are paid to QF developers as avoided costs are the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility, the utility would generate itself or purchase from another source.

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

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

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

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

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

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

ODOE has only described one portion of the methodology, and then uses that to support its conclusion that it should be the same for the proxy method. While no methodology is perfect in determining a utility's actual avoided costs, Idaho Power continues to maintain that a more accurate determination of actual avoided costs is the ICIRP. That method attempts to determine the cost of the resource being avoided in every hour of every day throughout the contract term. If a utility is in a resource sufficient period, the avoided cost of capacity portion of the payment is not included. And in Idaho, the additional refinement of the resource sufficiency period is implemented with the addition of each QF resource. The ICIRP methodology is much more sophisticated in its approach to the determination of the avoided cost. ODOE's conclusion that because a portion of the calculation of the avoided cost is included in the more refined ICIRP methodology, it is then "reasonable to use" in determining the avoided cost through the Oregon proxy method is just wrong and misleading. The proxy methodology is based upon the fiction/assumption that the utility avoids the cost associated with a CCCT, and assigns an avoided cost based upon the cost of that assumed CCCT. To the contrary, the ICIRP methodology calculates the utility's avoided cost specific to a particular proposed QF project, based upon the project's specific hourly generation forecast/profile. The ICIRP methodology compares the project's generation profile to the utility's resource stack being used to serve load in each hour and assigns the cost of the utility's highest cost displaceable resource operating during the hours that the QF provides generation. This is accumulated into monthly heavy and light load pricing. The Oregon proxy method is intended to be a simplified, transparent calculation, but does not capture all of the impacts of individual QFs on the Company's system. PacifiCorp Witness Dickman summarized with the following: "Fixing the capacity adder dollars paid to a QF implies that the QF can fully replace some portion of a CCCT, but does not recognize the benefits lost when a CCCT is replaced by a QF. Unless the full impact of adding a QF to a utility's system are accounted for, fixing the dollars paid for capacity inflates avoided cost prices and moves further away from avoided costs rather than closer." PAC/800, Dickman/11.

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

A. No. As I stated in my Direct Testimony in Phase II of Docket UM 1610, Idaho Power's Schedule 85 currently implements Order No. 14-058 properly by allocating a capacity payment to solar and wind QFs based upon a reduction from 100 percent of the capacity cost of proxy resource to each resource's contribution to peak from the acknowledged IRP, as directed in Order No. 14-058. To pay for generation that is not generated, or for capacity that is not provided, is contrary to the FERC definition of avoided cost. The utility's customers are ultimately harmed. For many years, the Oregon proxy methodology has determined an avoided cost rate that was only paid for those peak hours during which the renewable QF was actually generating and delivering energy to the host utility. What the modification in the approved Order No. 14-058 did was to differentiate between the differing QF resources, providing additional value to solar QFs as compared to wind QFs because of the operational characteristics of those different resource types. To modify the methodology now as Staff/Intervenors suggest would increase the avoided cost rate paid to the QF above the avoided cost rate of the proxy resource. As shown in my direct testimony, as well as the previous testimony and briefing on this issue from Idaho Power, the proposed changes actually result in compensating a solar QF for capacity at a higher rate than the 100% capacity proxy CCCT. This not is logically incorrect; it is harmful to the utility's customers and illegal. The current methodology approved in Order No. 14-058 should be affirmed by the Commission in this proceeding and Staff/Intervenor proposals rejected as requiring payment in excess of avoided costs.

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

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

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

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

> In calculating a QF's ability to contribute to a utility's need for capacity, we find it reasonable for the utilities to only begin payments for capacity at such time that the utility becomes capacity deficient. If a utility is capacity surplus, then capacity is 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.

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

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

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

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

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

PacifiCorp affirms that using market prices during the sufficiency period sufficiently compensates QFs for capacity, stating the "market prices generally represent the incremental cost of energy and capacity used to balance the Company's system prior to procuring its next major resource." PAC/800 Dickman/14. Staff is in agreement, and adds their view that "the relationship between the utilities' capacity needs during sufficiency periods and the prices for capacity paid to the QFs is sufficient to comply with PURPA." Staff/500 Andrus/30. Idaho Power would argue that payment for capacity during a period of resource sufficiency does not comply with FERC's definition of avoided cost as there are no incremental costs of capacity that are being avoided. While paying market prices for capacity may sufficiently compensate a QF project for capacity, if a utility is resource sufficient, it does not need any additional capacity. Paying any amount for capacity during a utility's Resource Sufficient Period, is an additional cost above the costs being avoided, and is harmful to the customers.

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

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

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

Mr. Higgins suggests requiring the development of an Alternative IRP scenario that re-determined the preferred resource portfolio absent the (assumed) renewing QFs in order to properly value the capacity that QFs would avoid. Joint QF Parties/100 Higgins/4-5. He also discusses at great length the uncertainty surrounding compliance with the Environmental Protection Agency ("EPA") under the proposed Section 111(d) rules of the Clean Air Act. Mr. Higgins recommends that the Commission adopt an interim capacity pricing mechanism for PacifiCorp's Schedule 37.

Q. What is Idaho Power's response to Mr. Higgins recommendations?

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

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

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

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

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

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

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

> Notwithstanding anything stated and agreed to in this Stipulation, as well as the accompanying Stipulation referenced in paragraphs B. above, Idaho Power hereby reserves the right to bring as separate case filings matters related to: (1) revision of the standard rate eligibility cap; (2) the appropriate maximum contract term;; (3) implementation of solar integrations charges; 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.

Subsequently, on April 24, 2015, Idaho Power filed three separate applications requesting that the Commission (1) lower the standard contract eligibility cap for wind and solar QFs to 100 kilowatts and reduce the term of wind and solar QF contracts to 2 years; (2) approve a solar integration charge; and (3) modify the Company's resource sufficiency period. All three applications were docketed under UM 1725 by the Commission, and are currently set for hearing on October 21, 22, and 23, 2015. The Commission has not yet ruled upon Idaho Power's request for clarification, and Idaho Power is unsure of the Commission's intent with regard to its statement to parties to "address in docket UM 1610 the level of solar integration charges to incorporate into avoided cost rates." At any event, Idaho Power has filed an application and direct testimony as well as its 2014 Solar Integration Study Report seeking the implementation of solar integration charges. To the extent that the Commission desires party positions regarding solar integration to be submitted in UM 1610, Idaho Power hereby incorporates the application, testimony, and supporting documents submitted in UM 1725 requesting the implementation of solar integration charges for Idaho Power.

Q. Does this conclude your testimony?

A. Yes, it does.

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IDAHO POWER COMPANY

RESPONSE TESTIMONY

OF

RANDY ALLPHIN

July 24, 2015

Q. Please state your name and business address.

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

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

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

Q. What is the purpose of your testimony?

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

Q. Please list the issues addressed by your Testimony.

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

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

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

<u>Issue 5</u>: What is the appropriate forum to resolve litigated issues and assumptions?

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

<u>Issue 8</u>: When is there a legally enforceable obligation?

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

Q. Please summarize your response testimony.

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

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

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

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

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

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

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

For compliance filing purposes, it is important to distinguish, between situations where the Commission has previously determined, during the course of a contested proceeding, that the utility should use a value obtained from the utility's IRP for an avoided cost input or purpose, and a situation where the Commission has not made such determination, but the utility utilizes a value from its IRP for an avoided cost input. Where the Commission has specifically directed the utility to use an input derived from the IRP, the only question for the compliance filing is whether the utility utilized the input identified by the IRP. The compliance filing should not be viewed as an opportunity to contest the use of that input—that opportunity was available to the parties during the course of the Commission's PURPA proceeding in which it ordered the utility use a value or input from the IRP for purposes of avoided cost calculations, or for whatever purpose that value is intended. Even if the Commission has ***not*** directed the utility to use a specific input from the IRP, parties should not be allowed to challenge such input in a compliance filing. Rather, if a party has an issue with a particular input, methodology, or practice with regard to avoided cost rates or the implementation of the utility's PURPA obligations, then those issues should be brought to the Commission through an application, petition, complaint, or investigation where the Commission can properly consider the issue through a contested proceeding.

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

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

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

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

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

> We conclude that this unprecedented pace and volume of QF development justifies interim relief in order to prevent harm to Idaho Power's ratepayers. We further conclude that such relief should be narrow, targeted, and proportionate. To that end, we adopt REC's suggestion and reduce the eligibility cap for Idaho 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.

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

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

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

The ICIRP methodology results in a project-specific avoided cost calculation that precisely matches the Federal Energy Regulatory Commission's ("FERC") definition of avoided cost. "Avoided cost means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 CFR § 292.101(b)(6). The methodology compares the project's specific hourly generation profile to the utility's resource stack being used to serve load in each hour, and assigns the cost of the utility's highest cost displaceable resource operating during the hours that the QF provides generation, as the avoided cost. The capacity component of the rate is based upon the generation resource type and the avoided cost of a simple-cycle combustion turbine and added to the energy component derived from the utility's hourly highest cost displaceable resources. The hourly values are accumulated into monthly heavy and light load pricing.

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

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

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

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

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

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

> In Order No. 09-439 in Docket UM 1449, a QF larger than 10 megawatts was in the process of negotiating a power purchase 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

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

Idaho Power/900 Allphin/11.

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

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

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

Q. Does this conclude your response testimony?

A. Yes, it does.