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July 24, 2015

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street, Suite 100
P.O. Box 1088
Salem, OR 97308-1088

Re: *In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Investigation into Qualifying Facility Contracting and Pricing*
PUC Docket No.: UM 1610 / Phase 2
DOJ File No.: 330-030-GN0240-12

To the Filing Center:

On behalf of the Oregon Department of Energy, enclosed for filing today with the Commission in the above-captioned matter are the following documents:

1. July 24, 2015 Testimony of Diane Broad, Exhibit ODOE/1000; and
2. July 24, 2015 Testimony of Philip Carver, Exhibit ODOE/900.

Sincerely,

for Renee M. France
Senior Assistant Attorney General
Natural Resources Section

Enclosures
RMF:jrs/#668388

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DOCKET NO. UM 1610
Phase 2
EXHIBIT: ODOE/1000
WITNESS: DIANE BROAD

Before the

PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Testimony of DIANE BROAD

July 24, 2015

Q. Are you the same Diane Broad that testified at ODOE/800?

A. Yes.

Q. What is the purpose of your response testimony?

A. I will address issue number nine from the ALJ memo of March 26, 2015. The other Oregon Department of Energy (ODOE) witness, Philip Carver, will address issues one, five, six and seven.

Q. What do you address in your response testimony?

A. First, I cite CREA's opening testimony[1] which concurs with ODOE's proposal that the qualifying facility (QF) should have a clear, transparent and consistent assignment of third-party transmission costs.

Second, I will revisit my opening testimony on the usefulness of providing QFs with transmission service options in the power purchase agreement (PPA) and the need for the Commission to define the term "load pocket." In the course of my response, I will address PacifiCorp's opening testimony[2], specifically the claim by PacifiCorp that long-term firm, point-to-point transmission is the only adequate option for securing transmission service to move generation from a QF out of load pocket.

ISSUE NUMBER NINE: HOW SHOULD THIRD-PARTY TRANSMISSION COSTS TO MOVE QF OUTPUT OUT OF A LOAD POCKET TO LOAD BE CALCULATED AND ACCOUNTED FOR IN THE STANDARD CONTRACT?

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[1] CREA/500/Skeahan/21

[2] PacifiCorp/1000/Griswold/24

Q. What is CREA's proposal relating to third-party transmission service costs for a QF located in a load pocket?

A. In the testimony of Brian Skeahan, CREA proposes that along with their avoided cost filing utilities, specifically PacifiCorp, should identify geographic areas of their system which are load pockets and provide specific information relevant to that load pocket: maximum hourly load per month and minimum hourly load per month.[3] ODOE supports this proposal and further recommends that utilities should disclose the annual cost ($/MW per year) for transmission out of the load pocket. This would give developers of QFs foreknowledge of whether their project would or would not be in a load pocket and what the likelihood would be to pay third-party transmission costs.

Q. What does CREA testimony have to say about utility benefits from the purchase of transmission service by the QF?

A. PacifiCorp can *and has* modified the point-of-delivery and point-of-receipt for the LTF PTP transmission which they own.[4] PacifiCorp would have the option of making this same modification with transmission service which they have procured on behalf of the QF and for which the QF has paid all costs.

CREA maintains that requiring the QF to purchase full-year, nameplate capacity LTF PTP transmission is not the same as covering costs. The purchase of more transmission than the QF needs over all the hours of the year, combined with the ability of PacifiCorp to re-allocate unused transmission capacity (within limits), results in a net

[3] CREA/500, Skeahan/22
[4] CREA/500, Skeahan/23

benefit to the utility during the hours of the year that the QF is not generating. This benefit should be calculated and the cost to the QF reduced accordingly.

Q. **Does PacifiCorp currently calculate the costs and benefits of third-party transmission for QF projects?**

A. Yes. In PacifiCorp testimony, the company states "Any costs and benefits of third-party transmission service should be attributed to the individual QF…."[5]

Q. Please summarize ODOE's proposal for transmission service provisions in standard QF contracts.

A. The Commission has ruled that when a QF has generation exceeding the minimum load in a load pocket, and third-party transmission must be secured, the QF must pay the cost for the transmission service. ODOE fully agrees with the Commission's position on this issue.

ODOE's concerns are ensuring that transmission service costs are clearly and consistently assigned, that QFs have options under the standard contract to choose transmission services that reflect their actual transmission needs, and that QFs have the information to make informed choices between these options.

Specifically, the standard contract should allow the QF to choose between LTF and STF transmission, with the understanding that STF transmission may result in curtailment of the generator under certain conditions. The standard contract should also offer the QF a choice of paying a transmission service fee (whether LTF or STF), sometimes

[5] PacifiCorp/1000, Griswold/21-22

called a contractual adjustment to billing, or taking a reduced payment per MWh generated. The transmission service fee would be assessed each month, regardless of the QF's actual generation, while the reduced payment would be by definition proportional to the QF's generation.

The standard contract should require greater transparency about whether a QF would be in a load pocket, the load profile in the load pocket and the cost of third-party transmission out of the load pocket, as proposed by CREA (discussed above). In addition, ODOE proposes that the standard contract require reporting by the utility of the real cost of transmission service associated with the QF, and a "true-up" at the end of the year which may result in a refund to the QF.

Q. What are the potential benefits to QFs of having the option to choose between LTF and STF third-party transmission service to move QF output out of a load pocket?

A. Transmission needs vary among QFs located in a load pocket depending upon the QFs capacity factor and the load profile in a particular load pocket. The transmission purchased should be based on the generation profile. Further, the transmission purchased should relate to the minimum load and number of low-load hours in the load pocket.

Limiting a QF to only long-term firm (LTF) point-to-point (PTP) transmission at the QF's nameplate capacity may result in the QF paying for significantly more transmission than is needed, which may have a negative impact on the financial viability of the project and/or the operational cash flow of the facility once built. By contrast, shortterm firm (STF) transmission can be purchased for one month ahead, meaning that transmission purchased can more closely match the excess generation by the QF.

Q. What are the practical implications of utilizing LTF vs. STF transmission service?

A. LTF transmission service can be purchased in one-year increments for a minimum period of one year. By making a commitment to purchase transmission service for a period of five years or more, the purchaser is assured the right to renew. With LTF PTP transmission, the QF is assured that all of its output for every hour will be able to reach load.

STF transmission service can be purchased in monthly, weekly, or hourly increments, but with no assurance of the right to renew. With STF PTP transmission, the QF may have periods of time when transmission service is not available. Those who hold higher priority transmission service contracts may "bump" those with STF service from the system. The QF would need to do a thorough analysis of the potential for being curtailed and the lost revenue associated with curtailment.

Q. Are both options for transmission service workable for the utility?

A. Yes, although there could be additional administrative costs under the STF option. If the QF had the option in the standard contract to purchase STF monthly, this could introduce additional administrative costs for the utility purchasing the transmission service on behalf of the QF.

In addition, the utility would need to include a provision in the contract enabling the utility to curtail the QF in the case of insufficient transmission service. The communication capability necessary for remote curtailment is typically provided by QF developers for any project with output equal to or greater than 3MW for system reliability reasons.

Q. If the utility incurs additional administrative costs due to securing STF PTP transmission, should these costs be included in the charge to the QF for transmission service?

A. Yes. The utility should provide a clear accounting of the administrative costs of securing STF PTP transmission, if that is the chosen transmission product for the QF. The Commission should clarify that the utility can be reimbursed by the QFs for these administrative costs, in addition to the cost for the transmission service itself.

Q. Why should a QF located in a load pocket have the option to accept a reduced MWh payment for its generation rather than paying a monthly fee for third-party transmission services?

A. The option to accept a reduced MWh payment for generation could provide more favorable cash flow projections for a QF seeking up-front project financing, especially if the monthly MWh output of the facility varies significantly throughout the year. A reduction in payment for generation is an option that brings more certainty to QF project costs and revenues as compared to paying the monthly fee for transmission service which may not be fully utilized. Greater certainty in project finances is an advantage to QFs during the development phase.

Q. Please elaborate on the reporting ODOE's proposal would require from utilities entering into a standard contract with a QF that would be located in a load pocket.

The standard contract should include the option for a finding every 5 years to determine whether the QF is still in a load pocket and whether, based on the current loads at that time, there is still a need for transmission service out of the load pocket.

ODOE's proposal for reporting actual costs for transmission service by the utility should not be administratively burdensome, nor should the proposed year-end "true up" and potential refund.

Q. What is ODOE's position regarding the definition of a load pocket and the information utilities should provide about any load pockets in their service territory?

A. There needs to be a clear definition of the term "load pocket." Load pockets in Oregon should be identified by the utility at the time of the utility's avoided cost filing, and the hourly maximum and minimum loads for each month of the year published with the avoided cost filing. ODOE encourages the Commission to consider a service area to be a load pocket only if third-party transmission is the sole means utilized by the utility to serve its load in that geographic area.

Q. Does this conclude your response testimony?

A. Yes.

DOCKET NO. UM 1610
Phase 2
EXHIBIT: ODOE/900
WITNESS: PHILIP CARVER

Before the

PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Testimony of Philip Carver

July 24, 2015

Q. Are you the same Phil Carver who testified at ODOE/700?

A. Yes.

Q. What is the purpose of your response testimony?

A. I will address issues number one, five, six and seven from the ALJ memo of March 26, 2015. The other Oregon Department of Energy (ODOE) witness, Diane Broad, will address issue number nine.

Q. What issues do you address in your response testimony?

A. On issue number one, I cite OPUC staff's opening testimony[1] which concurs with ODOE's proposal that the qualifying facility (QF) should own the Green Tags (a.k.a. renewable energy certificates or RECs) during the period of the contract for which the QF is paid market prices.

On issue number five, I will show how opening testimony by various parties shows the need to establish a contested case docket to run in parallel with each utility's integrated resource plan (IRP) docket, as proposed by ODOE. The purpose of the proposed docket would be to resolve issues and assumptions related to calculating each utility's avoided costs in a timely manner.

On issue number six, ODOE will respond to the testimony by Higgins[2] that proposes a specific capacity adder during PacifiCorp's sufficiency period.

On issue number seven, ODOE will respond to PacifiCorp's proposal in their opening testimony[3] regarding calculation of avoided costs for projects that do not execute standard contracts.

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[1] Staff/500, Andrus/2-6
[2] Joint QF Parties/100, Higgins

ISSUE NUMBER ONE: WHO OWNS THE GREEN TAGS DURING THE LAST FIVE YEARS OF A 20-YEAR FIXED PRICE PPA DURING WHICH PRICES PAID TO THE QF ARE AT MARKET?

Q. Does ODOE support the conclusion and reasoning of OPUC Staff at Staff/500, Andrus/2-6 on Issue Number One?

A. Yes. The key conclusion from Staff's testimony is reproduced below.

> ***Q. Does Staff agree with PacifiCorp's interpretation of Order No. 11-505?***
>
> *A. No. Staff believes that the Commission's requirement regarding REC transfer during renewable resource deficiency periods is based wholly on the fact that QFs are compensated for these RECs when they are paid deficiency-period prices based on the avoided fixed costs of the next avoidable renewable resource in the utility's Integrated Resource Plan (IRP). Staff believes that the Commission intended that QFs should retain the RECs when the QF is not compensated for the RECs with rates based on the avoided fixed costs of the next avoidable renewable resource.*[4]

ISSUE NUMBER FIVE: WHAT IS THE APPROPRIATE FORUM TO RESOLVE LITIGATED ISSUES AND ASSUMPTIONS?

Q. Please summarize your response testimony on Issue Number Five.

A. Proposals by the parties in their opening testimony either do not provide a timely resolution of disputed elements or do not allow parties to address the Commission on disputed elements. The Commission should find neither outcome acceptable. In contrast, ODOE's proposal of a contested case parallel

[3] PAC/800, Dickman/16-29
[4] STAFF/500, ANDRUS/4; lines 13-21

to the IRP acknowledgement case provides fair and timely resolution of disputed elements of utility avoided cost filings.

Q. What does OPUC Staff Propose?

A. Staff proposes that all issues related to calculating avoided costs, including the sufficiency/deficiency dates for non-renewable and renewable resources, be resolved in a contested case that would start at the conclusion of the IRP acknowledgment docket.[5]

Q. What does Staff conclude about the length of their proposed contested case?

A. Staff concludes that "[t]here is no statutory or other deadline on how long the Commission has to review the avoided cost filings."[6] Staff does not opine about whether this delay in revising avoided costs would create practical difficulties.

Q. What are the practical implications of Staff's proposal?

A. Under the Staff's proposal,[7] it appears that there would be an opportunity to completely rehear every issue in the IRP acknowledgement order related to avoided costs, including the deficiency date aspects.

Q. Does this seem workable?

A. No. Assuming a nine-month contested case avoided cost proceeding following the IRP acknowledgement order, new avoided costs would be implemented

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[5] Staff/500, Andrus/22-28,
[6] Staff/500, Andrus/28, at lines 9-11
[7] Staff/500, Andrus/25-26

roughly 18 months after the IRP was filed.[8] At the time of filing many of the inputs to the IRP are already one year old. Hence, under Staff's proposal many of the updated avoided costs could be stale by two and a half years. This undesirable delay would be avoided if the Commission adopts the parallel process proposed by ODOE.

Q. What process does Idaho Power propose to resolve this issue?

A. Idaho Power's proposal is similar to ODOE's in that they support a third type of proceeding, as opposed to using either the IRP docket or opening a contested case docket around the avoided cost compliance filing after the IRP docket is concluded.

Q. How does Idaho Power's proposal differ from ODOE's?

A. Idaho Power proposes:

> *If a party has 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 and make a decision or ruling as to the proper input, practice, procedure, etc.*[9]

This proposal differs from ODOE's proposal in that it does not call for a utility to file its avoided cost rates at the same time as it files its IRP.

[8] IRP acknowledgement dockets are typically conclude about nine months after the IRP is filed. For example, docket LC 62 has a special Commission hearing scheduled for Dec. 17, 2015 (http://apps.puc.state.or.us/edockets/Docket.asp?DocketID=19303&Child=calendar). PacifiCorp filed its IRP for this docket on March 31, 2015.
[9] Idaho Power/900, Allphin/5; lines 12-17

Q. Why is filing avoided costs after the Commission Order in a utility's IRP docket a problem?

A. First, Idaho Power's process is unworkable without an avoided cost filing at the time the IRP is filed. Until such a filing has occurred, there are no specific avoided cost input assumptions for a party to contest. Second, under Idaho Power's proposal the avoided cost filing would not be available until after the IRP acknowledgement order. Idaho Power notes that "past attempts to use … [avoided cost filing] dockets to litigate avoided cost inputs have resulted in confusion and delay."[10]

Q. What does PacifiCorp conclude about a contested case proceeding following the IRP acknowledgement order?

A. PacifiCorp notes that "Providing a **new** forum for litigating the IRP in the context of avoided cost pricing updates would incentivize wasteful litigation in an effort to delay the implementation of accurate pricing updates."[11] [Emphasis added].

Q. Does ODOE agree that a contested case proceeding after an avoided cost proceeding would be a "new" forum?

A. No. As pointed out by Staff,[12] Order No. 05-584 specifies that under the current process "[a]voided cost filings are subject to suspension and the same investigatory process that any tariff filing may undergo." Hence, allowing a contested case proceeding after an avoided cost filing is not new. The Commission recognizes that the IRP process is not designed to resolve all

[10] Idaho Power/900, Allphin/4; lines 20-21
[11] PAC/900, Drennan/12 lines 5-7.
[12] Staff/500, Andrus/22

technical issues. It is only designed to allow the Commission to acknowledge proposed action items to be implemented over the next four years. Items that are not critically related to action items are not resolved by an acknowledgement order.

Q. Does ODOE agree with PacifiCorp's statement above that a proceeding following the avoided cost filing at the conclusion of the IRP docket would be "wasteful litigation in an effort to delay the implementation of accurate pricing updates"?

A. Without attributing motives, ODOE agrees that it would delay implementation of more accurate avoided cost prices. It makes little sense to tack such a proceeding onto the end of the acknowledgement docket. Conducting a parallel process as recommended by ODOE would avoid this result.

Q. Which avoided cost inputs does ODOE propose should be settled in the IRP docket?

A. Load forecasts, natural gas prices and other elements integral to setting deficiency dates within four years of the IRP filing should be settled in the acknowledgement order. Only these inputs are eligible to be resolved by Commission decisions related to requests for acknowledgment of IRP action items.

Q. What about avoided cost inputs and assumptions not related to requests for acknowledgment of IRP action items?

A. All other issues related to setting avoided cost rates should be settled in the parallel docket that would be filed at the same time as the IRP, as proposed in ODOE's opening testimony.

Q. Do you agree with PacifiCorp that "Further litigation of IRP inputs and assumptions would simply rehash the issues with little or no additional benefits."[13]?

A. No. While the parties have opportunities to comment about the assumptions in the IRP during the acknowledgement docket, the Commission Order in that docket only addresses whether or not to acknowledge action items planned for the next four years. The Commission addresses only the assumptions implicit in these IRP action items. Meanwhile, the utility is not compelled to change assumptions in the IRP docket related to avoided costs based on comments by parties. Under the current process, the Commission does not adjudicate disputes over IRP inputs related to avoided costs until after the avoided cost filing.

Q. Do you agree with Staff that utilities should comply with Minimum Filing Requirements[14] (MFRs) when submitting their avoided cost filings either simultaneously with the IRP filing or after the IRP acknowledgement?

A. Yes.

Q. Do have any suggestions about the Staff's proposed MFRs?

[13] PAC/900, Drennan/11, lines 15-17
[14] Staff/503, Andrus/1

A. Yes. ODOE recommends adding to IV.3, "The sources of the costs for the avoided standard resource (typically a CCCT)." ODOE recommends adding to V.2, "The sources of the costs for the avoided renewable resource (typically a wind plant)." For V.7 ODOE recommends substituting "wind and solar integration costs, if applicable" for "wind integration cost" in both instances.

ISSUE NUMBER SIX: DO MARKET PRICES USED DURING THE RESOURCE SUFFICIENCY PERIOD SUFFICIENTLY COMPENSATE FOR CAPACITY?

Q. Have you reviewed the testimony of Kevin C. Higgins[15], sponsored by the Renewable Energy Coalition ("REC"), the Community Renewable Energy Association ("CREA"), OneEnergy, and Obsidian Renewables, LLC ("Joint QF Parties")?

A. Yes.

Q. What is your view of that testimony for this proceeding?

A. Without endorsing the particular values used in Higgins' calculations, the reasoning seems sound. The problem is that the approach put forward by Higgins relates to data in a specific IRP, while the data in the next IRP are likely to be different. Without a parallel process to dispute the inputs used in the avoided cost filing associated with the next IRP, there would be no way to update these values. Higgins' testimony shows the kind of disputes that should be resolved in the parallel proceeding discussed above. The particular

[15] Joint QF Parties/100, Higgins

estimates of capacity value during the sufficiency period covered by a specific IRP should not be resolved in this docket because this docket is a one-time event to settle questions of policy.

ISSUE NUMBER SEVEN: WHAT IS THE MOST APPROPRIATE METHODOLOGY FOR CALCULATING NON-STANDARD AVOIDED COST PRICES? SHOULD THE METHODOLOGY BE THE SAME FOR ALL THREE ELECTRIC UTILITIES OPERATING IN OREGON?

Q. **PacifiCorp states: "Independently calculating the avoided cost of large QFs using the PDDRR [Partial Displacement Differential Revenue Requirement] method is a more accurate approach for determining the value of the energy and capacity on the Company's system, taking into account the unique characteristics of each QF."[16] Do you agree with this statement?**

A. No. In Order No. 05-584 the Commission adopted a new methodology to determine the avoided cost rate during periods of sufficiency:

> *Consequently, of the two market-based valuation methodologies proposed by Staff, we* [the Commission] *adopt 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. We* [the Commission] *agree with Staff that this approach embeds the value of incremental QF capacity in the total market-based avoided cost rate.*[17]

[16] PAC/800, Dickman/16-17
[17] http://apps.puc.state.or.us/orders/2005ords/05-584.pdf, page 28.

Previously, decremental generating costs were used during periods of sufficiency. ODOE notes that regardless of its decremental cost of operation, the utility either is buying from the wholesale market or has the opportunity to sell into the wholesale market, which supports the use of wholesale prices to set avoided cost rates regardless of whether a utility is in an hourly deficit or surplus condition. By paying market prices to a QF, ratepayers are kept whole. Using the PDDRR method would go back to the method of using decremental generating costs during periods of sufficiency. This is not more accurate. The value of power during periods of deficiency is what the utility could sell it for or what it would buy it for, regardless of its decremental costs of generation.

Q. Does the method for calculating non-standard avoided costs need to be the same for all utilities?

A. While the methods may differ, the Commission should require that wholesale prices serve as the floor for avoided cost prices at all times. In this aspect all methods for calculating non-standard avoided costs should be the same.

Q. What is ODOE's position on using wholesale prices for the sufficiency period for setting QF prices?

A. ODOE supports the current Commission practice for PGE and PacifiCorp to use wholesale prices as the floor for QF prices that are fixed for the first 15 years. It is up to the Commission to assure that the forecast used represents a reasonable balance of risks for retail customers and QFs under PURPA.

Q. Does this conclude your response testimony?

A. Yes.