BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

IN THE MATTER THE PUBLIC UTILITY COMMISSION OF OREGON **Investigation Into Qualifying Facility Contracting and Pricing**	))))))))	**CASE NO. UM 1610**

Community Renewable Energy Association

Exhibit 500

Opening Testimony of Brian Skeahan

May 22, 2015

TABLE OF CONTENTS

I. Introduction

Q. Please state your name, employer, and business address.

A. Brian Skeahan, Community Renewable Energy Association, 1113 Kelly Avenue, The Dalles, Oregon, 97058.

Q. On whose behalf are you testifying?

A. I am submitting testimony on behalf of the Community Renewable Energy Association ("CREA").

Q. Please describe your educational and professional background.

A. I have a Bachelor of Arts in Political Science and Public Administration from the University of Nebraska, and a Master of Science in Public Administration from the University of Oregon. I had a 30-year career in the public utility industry, beginning at the Springfield Utility Board working in rates, power management and regional issues. I served as a General Manager at a municipal utility in Nebraska for seven years, at Klickitat PUD in Washington for nine years and at Cowlitz PUD for eight years. During this time I was heavily involved in renewable energy development and policy, wholesale and retail rates, and various Pacific Northwest regional power matters.

Q. Have you testified in previous cases before administrative agencies on energy regulatory topics?

A. I have testified and been an expert witness in Bonneville Power Administration ("BPA") rate proceedings.

Q. What is CREA's interest in this proceeding?

A. CREA is an Oregon Revised Statutes Chapter 190 intergovernmental association. CREA is a public/private organization whose members consists of individuals, businesses, and local governments seeking to promote locally-owned renewable energy projects for all forms of renewable generation recognized in Oregon's Renewable Portfolio Standard ("RPS") (biomass, geothermal, hydropower, ocean thermal, solar, tidal, wave, wind and hydrogen). CREA is comprised of several Oregon counties which provide active participation through their county commissioners, including Sherman, Wasco, Gilliam, Harney, Hood River, Morrow, Polk, Union, Wheeler, Curry, and Wallowa. In addition to these counties, CREA's current membership includes the Mid-Columbia Council of Governments, Columbia Gorge Community College, and 25 irrigation districts, businesses, individuals and non-profit organizations who have interests in a viable community renewable energy sector for Oregon.

Q. What is the purpose of your testimony?

A. I will first provide testimony on community renewable energy projects and the importance of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Then, I will provide CREA's position on each of the issues in Phase 2 of this docket, as set forth in the Administrative Law Judges' ("ALJ") Procedural Order entered on March 26, 2015. CREA is also jointly sponsoring the testimony of Kevin C. Higgins, who will address the technical and economic issues related to Issue 6: Whether the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity.

II. Community Renewable Energy and the Importance of PURPA

Q. What is community renewable energy?

A. Usually community renewable energy refers to projects of 20 MW or less that have substantial local ownership. Studies at Oregon State University, University of Minnesota, and the National Renewable Energy Laboratories have all documented that locally owned projects provide greater economic benefit to the local community than that which would be provided by a larger, absentee-owned project.[1] These studies have demonstrated that there can be a three to five-fold increase in economic returns and benefits to the local community over a larger, utility scale project. Simply put, with local investors a greater portion of the economic benefits of a community energy project stay within the local community compared to a project without local ownership or participation. Therefore, CREA believes that local ownership will result in increased economic development impacts for local Oregon economies.

Q. What are some of the difficulties and obstacles with developing a community-scale project?

A. Smaller scale, community renewable projects face all the same obstacles as larger scale projects – such as environmental permitting, land use laws, transmission access, and interconnection agreements. However, for smaller projects, the issues of financing and negotiating power purchase agreements, including rates, are much more difficult than for larger projects. Smaller projects by definition lack economies of scale. Costs associated with licensing, permitting, interconnection studies, and contract negotiations are somewhat inelastic – not varying in proportion to a project size. Even for relatively small projects with few environmental impacts, the studies and work associated with obtaining necessary licenses and permits can become a significant proportion of the costs of constructing smaller projects.

Similarly, economic and financial analysis required for financing for small projects can be a greater proportion of project costs. Banks and financing institutions tend to prefer larger

---

[1] *See* E. Lantz and S. Tegen, National Renewable Energy Laboratory, *Economic Development Impacts of Community Wind Projects: A Review and Empirical Evaluation*, (April 2009) , available online at http://www.nrel.gov/docs/fy09osti/45555.pdf (last accessed May 20, 2015); M. Torgerson, B. Sorte, and T. Nam, Oregon State University, *Umatilla County's Economic Structure and the Economic Impacts of Wind Energy Development: An Input-Output Analysis* (March 2006), available online at http://ruralstudies.oregonstate.edu/sites/default/files/pub/pdf/umatilla_sr1067.pdf (last accessed May 20, 2015).

loan amounts where the risk can be syndicated amongst several institutions. They also have understandable concerns regarding small projects whose revenues are fixed under purchased power agreements but whose project costs are not. But most challenging are the problems of actually negotiating a power purchase agreement and rates with a utility purchaser. The small business person or farmer attempting to incorporate a biomass generation project into their facility, or erect several wind turbines on their farm, or add solar panels to the roof of their building, frankly face an investor-owned utility ("IOU") that is not particularly welcoming, if not outright hostile to smaller independent power producers. While the small independent power producer must pay for the costs of negotiating contracts and applicable rates, the investor-owned utility's costs are ultimately paid for by the ratepayer creating significant imbalance of power in the negotiation. It is this imbalance of financial resources and subsequent power that PURPA is intended to mitigate.

Q. Could you provide some examples of community renewable energy projects?

A. While Oregon has a number of smaller QF type generation projects, there are a couple of good examples of "community" renewable projects. The 9-MW PáTu Wind and 3-MW Lime Wind community wind project outside of Baker City owned and developed by Randy Joseph from the Baker City area represent the benefits of small community-based projects. Washington has an interesting example in the Coastal Wind project in Grays Harbor County. Coastal Wind is a 6-MW community wind project that is owned by the Coastal Community Action Program. This project provides more than $500,000 through the Community Action Program to the community.

Minnesota leads the way for integrating a healthy community energy sector through the Community Based Energy Development ("C-BED") program that stimulates local community investment in renewable energy projects. As of June 30, 2008, there are a total of 57.3 MW of C-BED projects completed, another 57 MW of C-BED projects under contract, and an additional 721 MW of C-BED projects in negotiation. Although these are examples of community wind projects, the community ownership models can also apply to other renewable resource types.

Q. Does Oregon's Renewable Portfolio Standard refer to community renewable energy projects?

A. Yes, Oregon's RPS law specifically references community renewable energy projects. Specifically, the Oregon RPS statute states:

> "The Legislative Assembly finds that community-based renewable energy projects are an essential element of Oregon's energy future, and declares that it is the goal of the State of Oregon that by 2025 at least eight percent of Oregon's retail electrical load comes from small-scale renewable energy projects with a generating capacity of 20 megawatts or less. All agencies of the executive department as defined in ORS 174.112 shall establish policies and procedures promoting the goal declared in this section."[2]

Unlike the other RPS goals, this goal cannot be easily met by building a few large renewable (as defined in ORS 469A) energy plants because each project must be under 20 MW. I would note that based on information available to me, it appears that we have only achieved approximately two percent of Oregon load being supplied by renewable projects less than 20 MW.

Q. Are you aware of any policies or procedures of the Public Utility Commission of Oregon promoting this goal to promote community renewable projects with capacity of 20

[2] ORS 469A.210.

megawatts or less?

A. No.

Q. Are you aware of any policies that the individual utilities have in place to meet the 8 percent goal by 2025?

A. No, I am aware of no specific policy by either PacifiCorp or Portland General Electric Company ("PGE") that puts either utility on a path towards having eight percent of their loads being supplied by small (under 20 MW) renewable resources. When asked in discovery in Phase 1, none of the utilities in this docket were able to produce any specific policies they have in place to meet this goal. It is not clear how the utilities will meet this goal, which will require acquisition of a substantial number of projects under 20 MW. The combined loads of the IOUs in Oregon is approximately 31.4 million MWh. Eight percent of this load would be approximately 2.5 million MWh. This would require approximately 840 installed MW of 34 percent capacity factor wind, or almost 1,600 installed MW of 18 percent capacity factor for solar – all with projects sized less than 20 MW. Oregon's IOUs are nowhere close to this level, and their IRPs give no indication of any plan to attain it.

Q. Do you believe that PURPA is important to community energy projects?

A. Congress recognized the value of creating a competitive electric generation environment and the importance of smaller community-based projects in that competitive environment. Congress, and the Federal Energy Regulatory Commission ("FERC") in their implementation, understand that transacting with a utility through PURPA is one of the only means by which small, independent developers of renewable energy facilities may be able to develop projects and sell renewable energy. Proper implementation of PURPA is a critical element of providing community-scale projects with the ability to sell their output to an investor-owned utility under equitable terms and conditions, and is in no way anachronistic.

III. CREA's Position on Phase 2 Issues

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

Q. Please explain your understanding of the background regarding this issue.

A. The background on "green tags" or renewable energy credits ("RECs") associated with Oregon QFs' electrical output is set forth in existing Commission rules and orders.

Oregon Administrative Rule 860-022-0075 states that for contracts executed after the rule's promulgation:

> "Unless otherwise agreed to by separate contract, the owner of the renewable energy facility retains ownership of the non-energy attributes associated with electricity the facility generates and sells to an electric company pursuant to . . . (b) An Oregon contract with the electric company entered into pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978."

The Commission adopted that rule in 2005, based on the Staff's proposal, explaining:

> "Staff argues that renewable energy and the associated green tags are discrete products to be separately contracted for. Staff asserts that the United States Congress did not envision green tags when PURPA was enacted and that the Federal Energy Regulatory Commission (FERC) has recently concluded that contract pricing based on avoided costs do not compensate renewable energy power producers for the transfer of green tags. Staff notes that Oregon's

calculation of avoided costs is based on costs associated with a natural gas-fired plant that does not produce associated green tags."[3]

Subsequently, Oregon enacted its RPS law, and the Commission implemented a more-recent FERC order by creating the renewable avoided cost rates based upon the next planned renewable plant. The renewable QFs may elect the renewable rates instead of the standard rates discussed in the 2005 order. The Commission determined:

"Allowing a renewable QF to choose between the two avoided cost streams is consistent with FERC's ruling that clarified the right of the states to determine the avoided cost associated with utility purchases of energy 'from generators with certain characteristics.' Renewable QFs willing to sell their output and cede their RECs to the utility allow the utility to avoid building (or buying) renewable generation to meet their RPS requirements. These QFs should be offered an avoided cost stream that reflects the costs that the utility will avoid.

* * * *

"We agree with PGE that the renewable QF should be paid the market price throughout the renewable resource sufficiency period--even if the utility is non-renewable resource deficient. We find, however, that PGE's proposal that the utility make an additional payment to the QF for the REC is problematic and unnecessary. During the renewable resource sufficiency period the QF should be paid the market price and retain its RECs."[4]

Q. Please explain your understanding of the disputed issue.

[3] Order No. 05-1129 at 2-3 (footnotes omitted).
[4] Order No. 11-505 at 9.

A. The utilities offer the renewable avoided costs for a maximum period of 15 years after QF's online date. QFs have the option to extend the contract length to 20 years, but are only paid a projected market index price for output delivered in the last five years (years 16 through 20). The rationale and statements of Order No. 11-505 indicate that the QF retains ownership of the RECs when it is paid a projected market index rate during the sufficiency period, but the order does not expressly state who owns the RECs in years 16 through 20 of a 20-year contract. That is the disputed issue.

Q. Who raised this issue?

A. PacifiCorp.

Q. What is PacifiCorp's position?

A. PacifiCorp took the position that in renewable avoided cost contracts the utility should receive ownership of green tags in exchange for the market-based pricing in years 16 through 20 of the contract. In other words, PacifiCorp proposes to obtain ownership of the renewable attributes of the generation without paying a renewable-based price in years 16 through 20.

Q. Are you familiar with market-based price indexes and market purchases at Mid-Columbia and other regional market hubs?

A. Yes, previously in my career I have overseen selling and purchasing renewable and non-renewable energy at Mid-C, including BPA's "Slice" product.

Q. Do market purchases of electricity at Mid-Columbia and other regional market hubs convey ownership of RECs?

A. Typically not. The sales of short-term power and market index prices are generally energy-only sales for which the RECs and other environmental attributes are "unbundled." The seller can then either sell those RECs separately or retain them for compliance requirements they may have.

Q. Is there any logical basis supporting PacifiCorp's position?

A. I can see none whatsoever. Simply stated, PacifiCorp's position appears to be they have a right to procure something (the renewable attributes of a QF project) without paying for that, for a period of five years. By just receiving a market index price, the QF is not receiving any value for the environmental value of its power.

Q. What is CREA's recommendation?

A. CREA's recommends that, if the QF only receives market index prices from an IOU, then the QF should retain ownership of the RECs for the period which it is paid a projected market index price. However, if the QF conveys the RECs to an IOU during years 16 to 20, the IOU should pay the full renewable rate for those years, thereby fully compensating the QF for the value of the output the QF provides to the IOU.

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

Q. Please explain the background related to this issue.

A. This is an issue that the Commission should clarify from its order in Phase 1. CREA and other parties submitted substantial evidence that transmission costs from the non-renewable and renewable proxy resources must be included into the avoided cost rate calculations.[5] The Commission's order stated:

"We affirm the existing policy that if the proxy resource used to calculate a utility's avoided costs is an off-system resource, the costs of third-party

[5] CREA/300, Svendsen/12-15.

transmission are avoided, and are therefore included in the calculation of avoided cost prices. This is the situation for PGE, and it was not contested in these proceedings.

"If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs, and thus the costs of third-party transmission are not included in the calculation of avoided costs prices. This is the situation for Pacific Power."[6]

OneEnergy and CREA filed a joint motion for clarification/reconsideration pointing out that the Commission's statement regarding PacifiCorp's "on-system" resources overlooked extensive evidence in the record that expensive network transmission upgrade costs would be incurred to deliver output from PacifiCorp's proposed wind proxy resource in the Aeolus wind bubble in Wyoming. CREA and OneEnergy pointed to the evidence already in the record on this point.[7] In response, Staff argued that addressing "on-system" transmission costs was beyond the scope of Phase 1, which addressed only "third-party" transmission costs. The Commission denied reconsideration but deferred the issue to Phase 2, stating:

"We agree with Staff that One Energy and CREA ask for more than clarification of Order No. 14-058 yet fail to demonstrate that reconsideration of the order is warranted, as opposed to raising any additional or unanswered question(s) in Phase II of this docket."[8]

Q. What is the point upon which CREA seeks clarification?

---

6 Order No. 15-058 at 17.

7 *See* CREA/200, Reading/17-20; CREA/300, Svendsen/14-15; OneEnergy/100, Eddie/22, 31-32; OneEnergy/200, Eddie/7-9; RNP/200, Lindsay/13-14.

8 Order No. 14-229 at 2.

A. As indicated in the clarification/reconsideration motion which was deferred to this phase, CREA recommends that the Commission clarify that the cost of *any* transmission to move power from *any* proxy resource to the utility's load must be included in avoided cost rates.

Q. Why is this clarification necessary?

A. Excluding transmission costs required to bring generation output to load undermines the very concept of *avoided* cost. If the resource that an IOU is relying on is located outside of their load, costs are incurred to bring that resource to load. The record demonstrates, and it is commonly understood within the utility community, that utilities are confronting the need for new transmission infrastructure to bring resources to load. That infrastructure is often extremely expensive, faces considerable public opposition in many areas, and is time consuming to permit and construct. It is only reasonable that to the extent QFs help an IOU avoid, reduce or delay the costs associated with transmission to bring any proxy resource to load, the QF receive compensation for the value of that savings for the IOU. As matters currently stand coming out of Phase I, it is not at all clear the QF would in fact be fairly compensated.

Q. What is the specific clarification that the Commission could make?

A. As recommended in the clarification/rehearing filing, the Commission could simply clarify its statement in Order No. 14-058 at follows:

> If the proxy resource used to calculate a utility's avoided costs is an on-system resource <u>and able to serve load as a network resource without transmission upgrades</u>, there are no avoided transmission costs, and thus the costs of third-party transmission (<u>or on-system transmission upgrades</u>) are *not* included in the calculation of avoided costs prices.

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

Q. What is CREA's position on this issue?

A. CREA supports the positions set forth in the testimony of OPUC Staff, Oregon Department of Energy ("ODOE"), Obsidian Renewables, LLC ("Obsidian"), and OneEnergy filed during the solar capacity credit portion of this proceeding held in the time between Phase 1 and Phase 2. The Commission should adopt Staff's revised proposal for the capacity component of avoided cost rates as described in Staff/300 and Staff/400, to ensure that solar renewable QFs are compensated at the full avoided costs.

Staff proposed two separate rate design options to implement the correction to the double discount problem for solar renewable QFs.[9] The first option would compensate the solar renewable QF by spreading the volumetric payment for the capacity value over all NERC on-peak hours during which the solar QF delivers. The second option would only spread the volumetric payment for the capacity value over on-peak hours the QF delivers in the months of maximum need. CREA supports the first option for its simplicity. However, CREA agrees that each option would work so long as the volumetric rate is set at a level that is reasonably expected to pay a solar QF the full (single-discounted) capacity value over the course of the year.

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

Q. What is CREA's position on whether any corrections to the capacity contribution to peak calculation should also be corrected for QFs other than renewable solar QFs?

[9] Staff/300, Andrus/11-13.

A. ODOE also explains the same mathematical correction must be made with regard to standard (non-renewable) wind and solar avoided cost rates under the new capacity contribution to peak methodology.[10] CREA agrees with ODOE's position.

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

Q. What is CREA's position on the appropriate forum to resolve litigated issues and assumptions regarding the calculation of avoided cost rates in utility filings?

A. CREA's position is that avoided cost rates are like all other rates and must be reviewed and approved as reasonable by the Commission. My understanding is that the Commission must set the avoided cost rates and cannot simply allow the utility to calculate its own avoided cost rates. It is critical that interested parties should have the opportunity to fully review avoided cost rates and the myriad of assumptions that are behind those rates. It is also important that interested parties can identify what they believe are mistakes in the rates or underlying assumptions and argue that the Commission correct any inaccuracies. The utilities' position is that they can simply input figures about a proxy resource from an IRP into the avoided costs, and no party has any right to challenge those inputs as inaccurate. It is unclear whether QFs can raise issues related to avoided cost calculations in the IRP dockets and actually get the Commission to address that level of detail in an IRP, which is really focused on a host of matters other than avoided costs. It is also unclear that the procedural safeguards QFs are entitled to exist in the present IRP process.

While CREA understands and recognizes the value of the IRP process, the Commission should clarify where interested parties may raise these issues regarding avoided cost calculations

---

10 *See* ODOE/600, Brockman/2.

with resulting confidence that the Commission will address them in a contested case order. CREA does not believe that simply accepting inputs from an IRP into an avoided cost filing without our having appropriate rate-setting procedural safeguards in place is appropriate.

We look forward to responding to other parties' proposals on this issue in future rounds of testimony.

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

Q. Could you explain any concerns that CREA has with the sufficiency periods in the current avoided cost rates of Oregon utilities?

A. I have a number of concerns regarding sufficiency periods in the avoided cost rates filed by Oregon utilities. I do not believe avoided costs claimed by the utilities reflect their true avoided costs. I am concerned that they are based on a sufficiency period that, particularly in the case of PacifiCorp, is of an excessive duration; I am concerned that the avoided cost is overly reliant on market or front-office transaction purchases when PacifiCorp is actively incurring significant capital costs to retain capacity at existing coal and fossil-based generators; I am concerned that assumptions regarding the price of those market purchases may be unrealistically low, particularly in the out years; and I am concerned that relying on those purchases and associated price assumptions undervalues the capacity contribution provided to utilities by QFs. The utilities are claiming sufficiency not on the basis of their physical resources but unspecified and not yet made market purchases and prices not committed to.

Q. Why is this an important issue for CREA?

A. These sufficiency period prices, extending through 2020 for PGE and 2023 for PacifiCorp are insufficient to result in any significant development of new QFs. As discussed in

Ormand Hildebrand's testimony,[11] these low initial prices would make financing a project extremely difficult if not impossible for most developers and developments. As such it is important to determine if, in fact, the period of load/resource balance is reasonable and if the market prices on which sufficiency period avoided cost are based are also reasonable.

Q. Has CREA sponsored a technical witness addressing this problem and solutions that the Commission should adopt?

A. Yes. CREA has jointly sponsored the testimony of Kevin C. Higgins to address technical aspects of this issue. Mr. Higgins recommends solutions that the Commission should adopt.

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

Q. How do current Commission orders require the utilities to calculate the non-standard avoided cost rates in Oregon?

A. The Commission addressed this issue in Order No. 07-360. The order states at page 13:

> "For QFs under a legally enforceable obligation that choose avoided costs calculated at the time of the obligation, the yearly avoided costs approved for the 20-year period for standard contracts should serve as the starting point for negotiations, as we determined in the first phase of this proceeding. Idaho Power, however, may use the modeling methodology approved by the Idaho Public Utilities Commission for deriving avoided costs that serve as the starting point for negotiations with large QFs under a legally enforceable obligation. As it agreed to do, Idaho Power must incorporate stochastic analysis of electric and natural gas prices, loads, hydro, and unplanned outages. Idaho Power must comply with all

11 CREA 400, Hilderbrand/2-4.

other requirements set forth in this order for negotiating PURPA contracts and avoided cost rates with large QFs."

The Commission determined that PacifiCorp and PGE should use the standard avoided costs as a starting point but should use several factors to adjust the rates in accordance with FERC's factors for calculating avoided cost rates, 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.

Q. Why is this an issue at this time?

A. I understand that Idaho Power would like authorization to switch to a new computer modeling methodology different from that in place in 2007, and that PacifiCorp proposes to begin using an additional computer modeling methodology for Oregon QFs selling under non-standard rates.

Q. Did CREA provide testimony on this issue in Phase 1?

A. Yes. I refer the Commission to the testimony of Don C. Reading, which addresses the flaws in Idaho Power's new computer modeling methodology.[12]

Q. What is CREA's position on whether PacifiCorp or PGE should be entitled to use a modeling methodology for non-standard rates?

A. CREA opposes the mandatory use of computer models to establish non-standard avoided cost rates. CREA believes that the developer is inherently at a disadvantage in negotiation with IOUs that primarily rely on sophisticated computer modeling. These models can be very sophisticated, and often availability to the developer is contingent upon their purchasing expensive licensing fees, and acquiring outside expertise in operation of the model and its inputs.

[12] CREA/200, Reading/4-7.

The developer would incur significant costs very early on in the development process when it is most likely attempting to initially determine basic project feasibility. CREA fears that mandatory use of this type of modeling will essentially become a tool to obstruct QF development. If allowed, the Commission should adopt rules requiring the IOU to cooperate with the developer in use of the IOU's model to run scenario and sensitivity analysis in a transparent manner reasonably requested by the developer in order to develop a fair and equitable non-standard avoided cost rate.

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

Q. Did CREA address the question of when there is a legally enforceable obligation ("LEO") in Phase 1?

A. Yes. I refer the Commission to the testimony of Ormand Hilderbrand, which proposed use of an unexecuted contract filing requirement in order to form a legally enforceable obligation without obtaining a utility's signature on a contract.[13] The Commission deferred addressing the issue until this phase. CREA stands by the position set forth in Mr. Hildebrand's testimony, which concisely explains the unexecuted filing requirement that is already in use in the analogous circumstance under transmission tariffs and agreements under FERC's regulations for transmission and interconnection service.

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

Q. What aspects of this issue did the Commission resolve in Phase 1 of this case?

A. This issue is related only to PacifiCorp due to PacifiCorp's claim that it will occasionally incur costs to deliver QF output from the QF's point of delivery to PacifiCorp's load if the QF's point of delivery is located in a "load pocket" where generation occasionally exceeds load.

[13] CREA/100, Hilderbrand/17-20.

In Phase 1, the Commission determined:

"To answer the question of how costs imposed on a utility to arrange third-party transmission to transport QF output from receipt in a load pocket to load should be accounted for in a standard contract, we refer back to our discussion regarding imposed costs. We determine that when a QF located within a utility's BAA imposes integration costs on the utility, the avoided cost rates paid to the QF should be adjusted. We find this general principle – that avoided cost rates should be adjusted for costs imposed on a utility by the particular circumstances of a QF – to apply here.

"In applying this principle here, we first conclude that our adopted method of determining avoided cost prices based on avoided proxy resources reflects full avoided costs. Second, we conclude that any third-party transmission costs incurred by a utility to move QF output from the point of delivery to load would be costs that are not included in the calculation of avoided cost rates in standard contracts, and therefore are costs that are additional to avoided costs. Third, we conclude that any costs imposed on a utility that are above the utility's avoided costs must be assigned to the QF in order to comport with PURPA avoided cost principles. We find, however, that Staff and the parties did not fully address how to calculate and assign the third-party transmission costs that are attributable to the QF. We defer this issue to the second phase of these proceedings. We anticipate asking parties to recommend how third-party transmission costs to transport QF output from receipt in a load pocket to load should be accounted for in standard contracts; for example, by lowering avoided standard avoided cost

> rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means."[14]

Q. Did the Commission make any other statements in Order No. 14-058 relevant to costs to move transmission from a point of interconnection on the utility's system to the utility's load?

A. Yes. As discussed above, in addressing the related question of whether the avoided cost rates should be increased to account for transmission costs associated with the utility's on-system proxy resource, the Commission made the following statement:

> "If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs, and thus the costs of third-party transmission are *not* included in the calculation of avoided costs prices."[15]

Q. Do you believe it is equal treatment of QFs and proxy resources for the Commission to assign third-party transmission costs to an on-system QF but to conclude an on-system proxy resource could never impose any transmission costs?

A. No. PacifiCorp's contention – that third-party transmission costs should be assigned to a QF but a proxy resource could never impose transmission costs on a utility – is neither logical or in keeping with today's utility system realities. PacifiCorp's argument regarding avoided cost adjustments due to transmission costs is logically inconsistent and clearly discriminatory. PacifiCorp's argument appears to be based only on the scenario where the output of a QF has to be exported out of a load pocket due to minimum load restraints. They want to reduce rates afforded to QFs by assigning third-party transmission costs to an on-system QF in the event QF output exceeds load. That, in and of itself, may have merit. But then PacifiCorp argues an on-

---

[14] Order No. 14-058 at 22-23.
[15] Order No. 14-058 at 17.

system proxy resource could never impose any transmission costs. Somehow the output from Wyoming wind magically arrives in Oregon at no cost to PacifiCorp whatsoever. And they make this argument at the precise time they are arguing that Energy Gateway, a multi-billion dollar project, is needed to bring renewable energy from Wyoming to Oregon.

Q. What is CREA's position on load pocket costs assignable to QFs?

A. CREA has been addressing this issue for several years now, beginning in docket UE 235, and is very concerned that the Commission will adopt a policy that provides discriminatory avoided cost rates in violation of PURPA by refusing to increase avoided cost rates to account for transmission costs imposed by an on-system proxy resource and *reducing* avoided cost rates to account for transmission costs imposed by an on-system QF. There is already extensive testimony on these points in the record. The Commission should first correct its determination regarding transmission costs associated with on-system proxy resources as described in Issue 2 before it assigns the costs of third-party transmission to on-system QFs selling to PacifiCorp.

Q. What considerations should the Commission take into account in devising a scheme to assign third-party transmission costs to certain QFs delivering to load pockets where generation can exceed load?

A. There are certain considerations that should guide resolution of this issue. Our recommendation is based upon the principles of achieving transparency and understanding regarding a utility declaring an area is a load pocket, fairly capturing and allocating transmission-related costs and savings but for purchases from a QF, and utilizing opportunities to avoid or minimize transmission-related costs.

PacifiCorp appears to essentially be claiming almost their entire western service territory consists of load pockets. PacifiCorp's claim that its entire service territory consists of load pockets is intuitively suspect, and without documentation one cannot reasonably ascertain where the limitations or price adjustments on QF development within load pocket determinations are just and reasonable and where they are not. Furthermore, it is difficult to determine what the appropriate size of a potential QF might be in any given location based on the information PacifiCorp has been willing to share.

I have provided, as Exhibit CREA 501, a map produced by PacifiCorp in discovery that depicts its various "load pockets" and lists the QFs that are located within these load pockets that have executed a PPA since the time that PacifiCorp first raised this issue in Advice No. 11-011 on June 27, 2011 (Docket UE 235). In discovery, PacifiCorp indicated that only three of the 30 QF projects listed would require some sort of pricing or contract adjustment based upon the incremental third-party transmission costs associated with the "load pocket" problem. The QFs causing a load pocket problem where generation exceeded load occurred only in the Dalreed and Madras load pockets – despite PacifiCorp's insistence that any of the several other load pockets could be the site of the load pocket problem.

To provide clarity to QFs planning to site QF projects, PacifiCorp should include a map of its Oregon territory in its Schedule 37 that indicates areas designated as the load pockets, and the peak and minimum loads in these areas each month. PacifiCorp should also be required to provide a description of the amount of new QFs (in MW of capacity) that it can accommodate in each load pocket at the time of the filing updates to Schedule 37, with appropriate supporting documentation made with the filing. We further recommend that PacifiCorp be required to disclose any avoided cost rate reduction proposed in any load pocket location. This enables QFs to better plan and site their projects accordingly.

Q. In prior filings on this topic, PacifiCorp has claimed that it must assign to the QF the full costs of a long-term firm point-to-point ("LTF PTP") BPA transmission right if the QF will cause the generation to exceed load during any period of time during the year. Has PacifiCorp proven that this is a fair approach?

A: No. The evidence PacifiCorp provided indicates that the problem only arises during certain times of the year, indicating that this is typically not going to be a year-round problem.

PacifiCorp indicates that in most cases in Oregon the "third-party" transmission provider will be BPA. In a discovery response, PacifiCorp indicated they have contractual rights to 3,391 MW of BPA LTF PTP transmission rights, and acknowledged that they at times do not fully utilize the 3,391 MW of BPA transmission procured. PacifiCorp also acknowledged that BPA's transmission tariff allows them to change (or "re-direct") the point of delivery and point of receipt on those LTF PTP transmission rights on a long-term or a short-term basis, and that PacifiCorp has in fact done so to move output from the Three Mile Canyon Wind QF to PacifiCorp's loads. I have provided this discovery response to CREA data request 11.6 in Exhibit CREA 502.

This example demonstrates that assigning the full cost of year-round LTF PTP transmission right to the QF will overcharge the QF because PacifiCorp may be able to use BPA LTF PTP transmission it already owns to address the problem, or conversely the transmission PacifiCorp acquired for the QF could be re-directed to other uses during certain times, depending on the circumstances.

Q. Are there any other considerations?

A: Yes. BPA transmission service is evolving to accommodate growth in the amount of variable generation in the Pacific Northwest. Conditional firm products, development of rates for short-term firm and non-firm PTP service, and the utilization of unused PTP transmission rights on a secondary market are all reflective of these changes, and are intended to achieve a more efficient and economical use of the region's transmission systems. The Available Transmission Capacity (ATC) on the grid is also subject to changes as the transmission system is utilized in different and more efficient ways and the system itself is added to and improved. A single, long-term transmission solution imposed upon a QF is not in keeping with efforts in the Pacific Northwest to utilize the transmission system in the most efficient and economical way possible. On the other hand, my understanding is that federal and state law and regulations require the QF to be provided with the option to secure a fixed-price avoided cost rate for the duration of the contract based on reasonable estimated avoided costs at the time of contracting. Some QFs may prefer this option for financing purposes.

Q. Do you have any high-level proposals that could be developed into Schedule 37 to implement the Commission's directive?

A: First of all, PacifiCorp should be required to notify the QF if it is in a load pocket where this problem will exist very early in the negotiation process, and this issue should not be used to delay negotiations for the vast majority of QFs who will not impose this problem on PacifiCorp. Once the problem is identified, the alternatives proposed to the QF should include:

(1) Offer the QF a fixed avoided cost rate reduction based on the reasonably projected costs of securing LTF PTP transmission, with a reasonable offset for the value PacifiCorp should be able to recoup for its ability to re-direct the transmission procured for the QF to other uses at times when the QF's generation does not cause generation to exceed load. This option should be available to all QFs to ensure compliance with PURPA's fixed-price option. PacifiCorp has exhibited the ability to offer this option because it entered

into a contract with TMF Biofuels with a fixed cost projection for BPA transmission, as explained in response to CREA data request 9.2 and included in Exhibit CREA 502.

(2) Allow the QF to elect to enter into a contract term or addendum requiring the QF to pay PacifiCorp's incremental third-party transmission costs that are directly tied to moving its output to load. This option would require a contract term or addendum that also requires PacifiCorp to provide a monthly accounting of its actual costs that are assigned to the QF, including all instances where QF generation exceeded load, the third-party transmission that was purchased and used, an offset for any other uses PacifiCorp was able to make of the QF-allocated transmission during times when the QF generation did not cause generation to exceed load, and an explanation of why any unused transmission could not be re-directed for other uses during other times.

(3) Allow the QF to elect to enter into a contract term or addendum providing PacifiCorp with a narrowly limited curtailment right to address the load pocket problem. The curtailment right should be limited solely to instances where the QF output causes generation in the load pocket to exceed load, and where PacifiCorp is unable to re-direct its existing LTF PTP transmission rights to deliver the QF output to load. This option would require a contract term or addendum that also requires PacifiCorp to provide a monthly accounting of instances where QF generation exceeded load, and an attestation by PacifiCorp describing why it was unable to re-direct other LTF PTP transmission rights to alleviate the problem each time a curtailment occurred. If PacifiCorp cannot demonstrate it was unable to solve the problem by re-directing its other transmission rights, the contract clause would require PacifiCorp to compensate the QF for lost revenue during the curtailment. This option should be available because in some, if not

most, cases it may be more economic for a QF to curtail its output rather than pay for year-round LTF PTP transmission it only uses for a relatively small number of hours per year.

I emphasize that the QF should have the choice between these three options in order to ensure compliance with PURPA, transparency, and reasonable utilization of all available transmission options.

IV. Conclusion

Oregon's legislature has clearly articulated, through multiple actions, the desire to promote and encourage a power supply for Oregon that is low carbon, renewable and somewhat decentralized. Through proceedings such as UM 1610, the OPUC is charged with providing greater specificity to the legislature's policy direction and then implementing that policy direction in a way that achieves the energy goals for Oregon. How PURPA is implemented is a difficult but vital component in the success we have in achieving our objectives. Through my participation in the UM 1610 proceedings, it has become increasingly clear that Oregon's investor-owned utilities have made a determination to minimize their purchases of output from qualifying facilities under PURPA. Virtually every issue raised, and every position taken on these issues, appears intended to minimize QF development over the next decade. CREA believes that is contrary to the direction Oregon residents desire and what the legislature has directed.

CREA believes it is the OPUC's responsibility to assure that Oregon's investor-owned utilities comply with federal law as expressed by PURPA, Oregon's own related statutory provisions directly adopting PURPA, and Oregon's Renewable Portfolio Standard, which specifically includes provisions requiring Oregon agencies to support smaller community-based projects. While the Commission faces challenges in achieving these objectives, CREA believes that the Commission should step back and examine the course the State's investor-owned utilities would have us on and have had us on: construction of natural gas projects such as Carty 1 and 2, conversion of coal plants to natural gas, investment in environmental upgrades to continue generating from coal-fired plants, a significant reliance on market purchases at prices that are projections, out-of-state renewables and a minimal quantity of in-state renewables. CREA believes Oregon desires better and can do better. We believe that a properly implemented PURPA framework, embraced by the Commission, can result in an increasing portfolio of low-carbon renewable energy – one that is comprised of all forms of renewable energy as defined by the RPS, is decentralized, and provides benefits to local businesses, farms and families by connecting Oregonians to an energy supply with which they are familiar and supportive.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

IN THE MATTER THE PUBLIC UTILITY COMMISSION OF OREGON	)))	**CASE NO. UM 1610**
Investigation Into Qualifying Facility Contracting and Pricing	)))))	

Community Renewable Energy Association

Exhibit 501

PacifiCorp Load Pocket Map

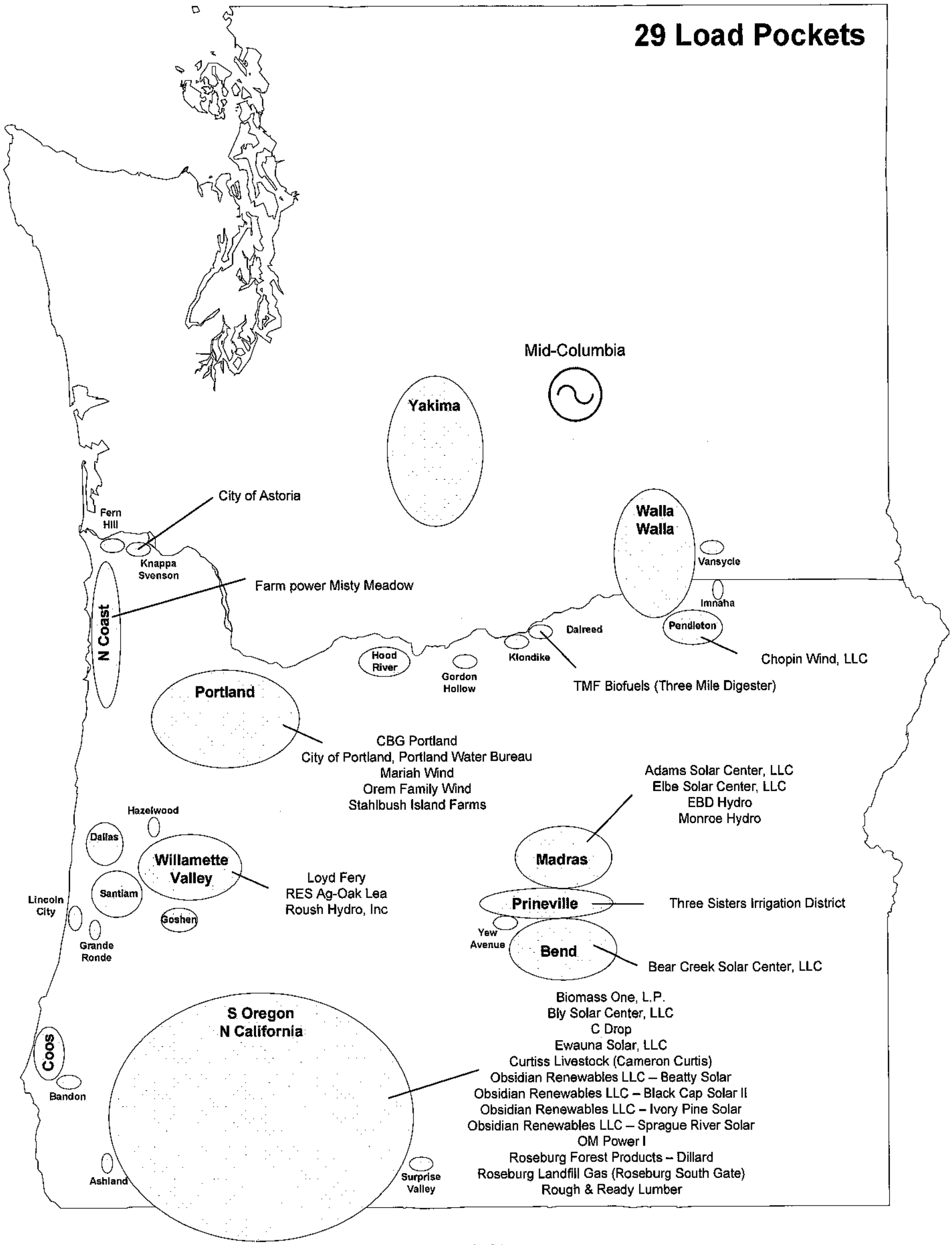
Attachment to Response to CREA Data Request 11.8

May 22, 2015

OR UM 1610
CREA 11.8

Attachment CREA 11.8

PACW – Load Pockets



BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

IN THE MATTER THE PUBLIC UTILITY COMMISSION OF OREGON	)	**CASE NO. UM 1610**
Investigation Into Qualifying Facility Contracting and Pricing	)	

Community Renewable Energy Association

Exhibit 502

Responses to CREA Data Requests 11.6 and 9.2

May 22, 2015

UM 1610/PacifiCorp
April 30, 2015
CREA Data Request 11.6

CREA Data Request 11.6

Reference BPA's OATT, section 13.7, stating:

The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(a) Please explain how much capacity (MW) of firm point-to-point transmission PacifiCorp possesses.

(b) Are all of the point-to-point transmission rights identified in subpart (a) fully utilized during all hours of the year?

(c) Please explain whether PacifiCorp has ever considered redirecting any of its existing firm point-to-point transmission rights on a non-firm basis under Section 22.1 of the OATT for the purpose of delivering QF output to load out of a load pocket. If yes, please indentify the QF, load pocket, and explain why PacifiCorp decided to redirect the transmission to deliver QF output or not.

(d) Please explain whether PacifiCorp has ever considered redirecting any of its existing firm point-to-point transmission rights on a firm basis under Section 22.2 of the OATT for the purpose of delivering QF output to load out of a load pocket. If yes, please indentify the QF, load pocket, and explain why PacifiCorp decided to redirect the transmission to deliver QF output or not.

(e) If the response to (c) or (d) was yes, please provide all documents exchanged between PacifiCorp Transmission and PacifiCorp Merchant personnel (including all QF contract administrators); as well as all documents exchanged between BPA and PacifiCorp.

Response to CREA Data Request 11.6

(a) The Company has contractual rights to 3,391 megawatts (MW) of Bonneville Power Administration (BPA) long-term firm (LTF) transmission.

(b) No. There are times during the year when portions of the 3,391 MW referenced in the Company's response to subpart (a) above is not fully utilized.

(c) Yes. The Company has redirected BPA LTF transmission on a non-firm (NF) basis to deliver Three Mile Canyon Wind output to both the Yakima and the PacifiCorp West (PACW) load pockets. The Company redirected LTF transmission because it was not fully utilized and on a NF basis because firm was not available.

UM 1610/PacifiCorp
April 30, 2015
CREA Data Request 11.6

(d) Yes. The Company has redirected BPA LTF transmission on a firm basis to deliver Three Mile Canyon Wind output to both the Yakima and the PACW load pockets. The Company redirected LTF transmission because it was not fully utilized.

(e) No documentation is required or exchanged during the short-term redirect process which is fully executed on BPA's internet Open Access Same Time Information System (OASIS).

UM 1610/PacifiCorp
April 14, 2015
CREA Data Request 9.2

CREA Data Request 9.2

For each QF PPA listed in response to request 9.1(d) where PacifiCorp determined that the QF's point of delivery would be to a load pocket, identify the QF PPA and describe in detail how PacifiCorp resolved the load pocket issue for each such QF PPA, e.g., by refusing to sign a standard PPA with standard avoided cost rates, signing a standard PPA with standard avoided cost rates, signing a PPA with avoided cost rates lower than standard avoided cost rates, assigning transmission costs to the QF, implementing curtailment, or some other resolution. For each QF discussed, provide a copy of all finally executed QF PPAs and all related agreements regarding allocation of third-party transmission costs to PacifiCorp or the QF.

Response to CREA Data Request 9.2

Referencing the Company's response to CREA Data Request 9.1; specifically Confidential Attachment CREA 9.1, column F, there are three qualifying facilities (QF) identified that are located in load pockets that have applicable transmission service requirements to move the excess generation out of the load pocket. Please refer to the table below:

QF Project	Resource Type	Size Megawatts (MW)	Commercial Operation Date (COD)	Term (Years)	Load Pocket Location
Adams Solar Center, LLC	Solar	10.00	April 30, 2017	20	Madras
Elbe Solar Center, LLC	Solar	10.00	April 30, 2017	20	Madras
TMF Biofuels	Methane / Biogas	4.80	December 31, 2012	10	Dalread

Adams Solar Center LLC (Adams) – The power purchase agreement (PPA) for Adams was executed August 7, 2014, after the Phase I Order in Docket UM 1610 was issued[1], which assigns to the QF the cost of the transmission service for excess generation out of the load pocket to load. Adams and Elbe Solar Center LLC (Elbe) have the same developer and owner. The developer and PacifiCorp completed an addendum to the PPA (Addendum B) which outlines how the transmission service would be acquired and how the costs would be billed to Adams. PacifiCorp is currently working with the developer to procure the transmission service from Portland General Electric (PGE) and the Bonneville Power Administration (BPA) for both Adams and Elbe on the time schedule established by the PPA. Please refer to Attachment CREA 9.2, which provides a copy of the Adams PPA.

Elbe Solar Center LLC (Elbe) – The PPA for Elbe was executed August 7, 2014, after the Phase I Order in UM 1610 was issued which assigns to the QF the cost of the transmission service for excess generation out of the load pocket to load. Elbe has the same developer and owner as Adams. The developer and PacifiCorp completed an addendum to the PPA (Addendum B) which outlines how the transmission service would

[1] Public Utility Commission of Oregon (OPUC) Order 14-058 issued February 24, 2014.

be acquired and how the costs would be billed to Elbe. PacifiCorp is currently working with the developer to procure the transmission service from PGE and BPA for both Adams and Elbe on the time schedule established by the PPAs. Please refer to Attachment CREA 9.2, which provides a copy of the Elbe PPA.

TMF Biofuels (TMF) - The PPA for TMF was executed February 21, 2012, before the Phase I Order in UM 1610 was issued which assigns to the QF the cost of the transmission service for excess generation out of the load pocket to load. However, the developer for TMF agreed to and negotiated a dollar per megawatt-hour ($/MWh) adjustment to the avoided cost price in the TMF PPA to compensate PacifiCorp for the transmission service from the Bonneville Power Administration (BPA) to move excess generation out of the Dalread load pocket. PacifiCorp and TMF completed an addendum to the PPA (Addendum A) which outlines how the transmission service would be acquired and how the costs would be billed to TMF. The commercial operation date (COD) for TMF occurred on December 31, 2012. Please refer to Attachment CREA 9.2, which provides a copy of the TMF PPA.