PACIFIC POWER
A DIVISION OF PACIFICORP

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May 22, 2015

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
3930 Fairview Industrial Dr. S.E.
Salem, OR 97302-1166

Attn: Filing Center

RE: UM 1610 Phase II—Investigation into Qualifying Facility Contracting and Pricing Opening Testimony of PacifiCorp

PacifiCorp d/b/a Pacific Power encloses for filing in this docket the opening testimony of Brian S. Dickman, Ted Drennan and Bruce W. Griswold.

It is respectfully requested that all formal data requests to the Company regarding this filing be addressed to the following:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Please direct informal inquiries to Erin Apperson, Regulatory Affair Manager at (503) 813-6642.

Sincerely,

R Bryce Dalley / NCS

R. Bryce Dalley
Vice President, Regulation

Enclosures

CC: UM 1610 Service List

Docket No. UM-1610
Exhibit PAC/800
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Opening Testimony of Brian S. Dickman

May 2015

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Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs and Load Forecasting.

QUALIFICATIONS

Q. Briefly describe your education and business experience.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Prior to joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing. I have been employed by the Company since 2003, including positions in revenue requirement, regulatory affairs, and net power costs. I assumed my current role directing the Company’s net power cost and load forecast groups in April 2015.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony addresses issues identified for consideration in Phase II that relate to the calculation of avoided costs. Specifically, I address issues 2, 3, 4, 6, and 7 on the issues list established in the March 26, 2015, ruling in this case, and my testimony is structured to follow the list order.

Q. Did you file testimony in Phase I of this proceeding?

A. Yes. My testimony in Phase I focused on issues related to the method for calculating avoided cost prices, including identifying the appropriate method for standard and non-standard prices, determining a schedule for price updates, and accounting for specific QF characteristics.

Q. Are any other Company witnesses presenting testimony in Phase II?

A. Yes. Mr. Bruce W. Griswold, Director of Short-Term Origination & Qualifying Facility Contracts, presents testimony regarding commercial issues related to QF contracting in Oregon. Specifically, Mr. Griswold addresses issues 1, 8, and 9 from the docket UM 1610 Phase II issues list. Mr. Ted Drennan, the Company's Integrated Resource Plan (IRP) manager, presents testimony addressing issue 5 from the docket UM 1610 Phase II issue list.

Q. Please summarize your testimony.

A. In Phase I of docket UM 1610, the Commission retained the existing methodology for calculating standard avoided cost prices and standard renewable avoided cost prices (the Proxy Method), with modifications to account for capacity contribution of different QF resources and wind integration costs. While the modifications adopted improved the accuracy of published avoided cost prices, the Proxy Method is still a simplified calculation that overstates the value of a QF on PacifiCorp's system. The Commission should reject the additional modifications to the Proxy Method at issue in Phase II because they would cause the published avoided cost prices to further depart from the Company's actual avoided costs to the detriment of its retail customers. Adjusting avoided cost prices by including additional costs related to transmitting electricity across PacifiCorp's system and capacity costs in addition to market prices when the utility is in a sufficiency period, or by fixing capacity payments to intermittent QFs regardless of their actual generation, increases prices paid to QFs but does not accurately represent costs that can be avoided by the Company.

With respect to non-standard avoided cost prices, the Company recommends a modeling approach that measures the project-specific impact a particular QF has on the Company's costs. For PacifiCorp, this is accomplished through its Generation and Regulation Initiative Decision Tools (GRID) production cost model. This modeling approach, known as the Partial Displacement Differential Revenue Requirement (PDDRR) method, is commonly used by the Company in its other jurisdictions to calculate non-standard avoided cost prices.

Utilizing the PDDRR method will improve the accuracy of the avoided cost prices for large QFs that do not qualify for standard avoided cost prices, compared to the current approach of making limited, discrete adjustments to the simplified Proxy Method. The PDDRR method directly measures the impact each QF facility has on the Company's power costs by utilizing GRID to calculate the value of energy and capacity from QFs based on the unique characteristics of each QF resource and the Company's system. As QF projects increase in size and developers are more sophisticated, it is necessary that avoided cost prices be as accurate as possible in order to meet the standard of utility customer indifference. As such, inputs to non-standard avoided cost prices should reflect the best available information at the time a QF requests prices, including recognition of other signed and potential QFs on the Company's system.

ISSUE 2: SHOULD AVOIDED TRANSMISSION COSTS FOR NON-RENEWABLE AND RENEWABLE PROXY RESOURCES BE INCLUDED IN THE CALCULATION OF AVOIDED COSTS?

Q. Does the Company include any avoided transmission-related costs in the cost of non-renewable and renewable proxy resources?

A. Yes. The proxy resources used for non-renewable and renewable avoided costs include all costs of the project switchyard and generator interconnection, including: transmission line from the project switchyard to the point-of-interconnection substation, metering transformers and circuit breaker, interconnection substation property and rights-of-way, and transmission function direct assigned facility costs. Direct assigned facilities are the portions of facilities that are constructed for the sole use/benefit of a particular transmission customer. They are distinguished from network upgrades which represent facilities that are integrated with and support the Company's transmission system for the general benefit of all transmission users.

Q. Do the proxy resources require third-party transmission service to reach PacifiCorp's service territory?

A. No. Planned resource acquisitions included in the Company's IRP are sited within PacifiCorp's service territory and do not require third-party transmission service to reach the Company's system. In Phase I, Staff proposed to include avoided transmission costs in the standard and renewable avoided cost prices if the avoided resource is an off-system resource that requires third-party transmission to deliver energy and capacity to the utility's system.[1] PacifiCorp plans to meet its resource needs on a system-wide basis and new resources are planned to be located on-system.

[1] Staff/100, Bless/6.

Therefore, off-system transmission costs are not avoided and should not be included in PacifiCorp's avoided cost prices.[2]

Q. Should standard renewable and non-renewable avoided costs include avoided costs of transmission service to move energy across the Company's multi-state service territory?

A. No. PacifiCorp operates its resources as a multi-state system and a portion of Company resources, and any associated renewable energy credits, located all across the Company's service territory are allocated to Oregon customers. The Company utilizes its transmission rights to serve customers and optimize the dispatch of its system to the benefit of all retail customers. Company-owned transmission infrastructure and contractual rights on third-party systems are needed to operate PacifiCorp's system whether it adds QF or non-QF resources. Taken to the extreme, if all of the resources in the Company's portfolio were QFs, the Company would still need transmission infrastructure and contractual rights to move the output of those resources to load. Consequently, avoided costs should not include assumed reductions in transmission service costs due to the addition of a QF.

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. Please explain the concept of a capacity contribution adder for solar QFs.

A. The concept of a capacity contribution adder arose through implementation of the standard renewable avoided cost rate as it is currently applied to solar QFs. In

[2] *S. Cal. Edison Co.*, 71 FERC ¶ 61,269, 62080 (June 2, 1995) ("[I]n setting avoided cost rates, a state may only account for costs which actually would be incurred by utilities.")

compliance with Order No. 14-058 in Phase 1 of docket UM 1610, this calculation is applicable in the resource deficiency period when the QF is assumed to avoid a proxy renewable resource – in PacifiCorp's 2013 IRP the proxy renewable resource was a future wind project. If the renewable QF is of a different type than the proxy (e.g. a solar QF versus a wind proxy), the Commission found that the QF may be able to defer additional capacity beyond the wind proxy capacity, based on the relative capacity contribution of the QF. If the QF is deemed to defer more capacity than that of the proxy resource, then capacity costs of a proxy combined cycle combustion turbine (CCCT) are added to the on-peak standard renewable rate. This second capacity deferral is referred to as the capacity adder.

Q. Did the Company provide testimony on this issue previously in this case?

A. Yes. Company witness Mr. Gregory N. Duvall sponsored testimony in an earlier phase of this case addressing the calculation of the capacity contribution adder for solar QFs selecting the standard renewable avoided cost prices. His direct and reply testimony on this issue was provided as Exhibit PAC/700.

Q. Please summarize the Company's testimony already provided as it relates to the solar capacity adder.

A. In Exhibit PAC/700, the Company demonstrated that the calculation of the solar capacity adder as proposed by Staff, and adopted by the Commission in Order No. 14-058, is consistent with the method for including capacity in standard avoided cost prices, as has been approved for many years. Under the approved method, the solar capacity adder is calculated in the same manner as the capacity costs are calculated under the standard rate (i.e. the proxy CCCT capacity costs are converted to a dollar-per-megawatt-hour rate using the proxy resource capacity factor then applied to all on-peak hours). Under this method, the capacity costs of the proxy are paid to a QF based on the QF's generation during on-peak hours.

On April 24, 2014, Obsidian Renewables LLC (Obsidian) filed a motion for clarification in which it claimed that applying the capacity adder on a dollars-per-megawatt-hour basis results in an inadvertent "double discount" of the capacity payment to a solar QF because the solar QF has a relatively low capacity factor and does not generate the same amount of energy as the capacity resource. Obsidian argued that the capacity adder should be paid as a fixed dollar amount to the QF rather than depend on the QF's actual energy output. OneEnergy Inc. and the Community Renewable Energy Association (CREA) also filed a motion for clarification, which supported the claims made by Obsidian. OneEnergy and CREA proposed that the proxy capacity costs could be spread using the QF's capacity factor rather than capacity factor of the proxy resource. The result of this proposal is the same as Obsidian's.

Arguments supporting a change to the Commission's approved capacity contribution adder boil down to a proposal that the solar capacity adder be paid as a fixed dollar amount and that each solar QF receive the fixed dollar amount regardless of its actual output during on-peak hours.

Q. Why is it appropriate for standard rates to pay a QF capacity costs only when it generates, rather than paying QFs fixed capacity payments?

A. For standard rates, avoided costs are a simplified calculation and prices are published for all QFs that meet the eligibility requirements. During the deficiency period standard avoided costs are equal to the cost of a proxy resource, but are intended to reflect the "actual deferral or avoidance of that resource."[3] Fixing the capacity adder dollars paid to a solar QF implies that the solar QF can fully replace a renewable proxy *and* a portion of a CCCT, but does not recognize the benefits lost if a CCCT is actually displaced. Adopting this approach inflates the standard renewable avoided cost prices and moves the method further away from avoided costs rather than closer.

Q. Please describe the lost benefits from the proxy CCCT capacity which are not accounted for if a QF is paid a fixed capacity adder.

A. The capacity costs of a proxy CCCT provide several benefits to the utility that are not provided by an intermittent solar QF, including the ability to dispatch the resource on an as-needed basis and the ability to provide operating reserve capacity. The Company is required to have sufficient contingency reserves available within 10 minutes to ensure reliable service in the event of unexpected generation or transmission outages. The Company is also required to have sufficient generating capacity available to compensate for moment-to-moment changes in the load and resource balance on its system. Combined cycle plants can ramp over most, if not all, of their dispatchable range within 10 minutes and thus have significant reserve carrying capability.

Q. Do you recommend any change to the calculation of the capacity adder portion of the currently-approved standard renewable avoided cost rate?

A. No. The Commission should re-affirm its decision reached in Order No. 14-058 and reject additional changes to the standard renewable avoided cost prices that further

[3] Docket No. UM 1129, Order No. 05-584 at 26.

widen the difference between avoided cost prices and the costs that a utility actually avoids.

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. Please briefly describe the current calculation of standard avoided costs.

A. Under the Commission-approved method that has been in place for many years, standard avoided costs are a based on a simplified calculation that assumes a utility's avoided costs are equal to market prices during the sufficiency period and the cost of a proxy resource (i.e. the next deferrable major thermal resource in the Company's acknowledged IRP, currently a CCCT) during the deficiency period. Standard avoided cost prices during the deficiency period are differentiated into on- and off-peak periods. Off-peak prices are equal to the fuel costs of the proxy CCCT plus a small amount of capitalized energy costs. On-peak prices include the fixed costs of the proxy CCCT, spread across on-peak hours based on the expected generation of the CCCT. In Order No. 14-058, the Commission approved a change to recognize the capacity contribution of different QF resource when calculating the capacity costs that are included in standard avoided cost prices.

Q. How is the capacity contribution applied in the approved standard avoided cost prices?

A. For wind and solar QFs choosing the standard non-renewable avoided cost prices, after the capacity costs of the proxy CCCT are determined on a dollar-per-megawatt-hour basis during on-peak periods, they are reduced by applying the capacity contribution percentage for each type of QF. For example, for a solar QF the standard avoided cost prices during on-peak periods include 13.6 percent of the capacity costs of a CCCT.

Q. Please describe what change would be made if standard non-renewable avoided cost prices were to mirror the change to capacity costs proposed for the standard renewable avoided cost prices.

A. As with the standard renewable avoided costs, the issue of changing the calculation of capacity costs under standard non-renewable avoided cost prices boils down to whether the fixed costs 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. Given the simplified nature of the standard avoided cost method, paying a QF a fixed amount for capacity regardless of when it generates does not recognize benefits that are lost when a CCCT is displaced by an intermittent generating resource.

Q. Have you calculated the impact of including a fixed capacity payment in standard avoided costs instead of the current volumetric prices?

A. Yes. In 2024, the first year of the deficiency period under current standard avoided costs, paying QFs a fixed capacity payment increases the annual average price paid between $1.35/MWh and $4.90/MWh, depending on the type of QF.

Table 1
Standard Avoided Cost Prices – 2024, $/MWh

	Baseload	Wind	Solar
Current Rates	$56.51	$36.66	$42.60
Fixed Capacity Payment	$57.85	$38.16	$47.50
Difference	$1.35	$1.50	$4.90

Q. Why is it appropriate for standard avoided cost rates to pay a QF capacity costs only when it generates, rather than paying QFs fixed capacity payments?

A. The same logic applies here as described in the previous section on standard renewable avoided costs. The standard avoided cost method is a simplified calculation that does not capture the impact of individual QFs on the Company's system. Avoided costs during the deficiency period reflect the deferral or avoidance of a proxy resource that is most likely a different resource type than the QF. 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.

Q. Can you elaborate on the benefits from the proxy plant which are not captured by the current Proxy Method?

A. Yes. In the 2013 IRP, the proxy resource (a 425 MW CCCT) was assumed to operate at a 56 percent capacity factor, while the assumed forced and planned outage rates of 2.5 percent and 3.8 percent, respectively, result in an expected availability of 93.7 percent. This leaves roughly 38 percent of the plant's capacity seemingly unused.

This unused capacity represents two benefits provided by a combined cycle plant. First, when market prices are lower than the operating cost of the plant, it can be dispatched down to minimum or taken offline overnight. While the plant is backed down or offline, its output can be replaced by lower cost market purchases. The ability to procure electricity at a lower cost during such periods results in lower operating costs and provides a benefit to customers. Under the Proxy Method, the Company and customers pay the proxy plant's generation cost for all QF generation, even during periods when the proxy plant would have been offline and replaced by lower cost market purchases.

The second benefit available from the unused generating capacity of a combined cycle plant is reserve carrying capability. As described earlier, the Company is required to hold capacity in reserve to ensure reliable service in the event of unexpected generation or transmission outages and to compensate for moment-to-moment changes in the load and resource balance on its system. Rather than generating, the proxy plant's reserve carrying capability can free up the generation from lower-cost resources and reduce operating costs, again providing a benefit to customers.

In addition to the lost capacity benefits, if the QF resource has a low capacity factor, there may be a net reduction in energy that would need to be replaced if the proxy resource is displaced. The cost of this lost energy is not accounted for using the Proxy Method. Rather, under the Proxy Method customers pay the proxy plant's generation cost for all QF generation, ignoring the cost savings associated with using the full flexibility of the proxy resource.

Q. Has the standard avoided cost calculation used by the Company in the past, and re-affirmed by the Commission in Order No. 14-058, been thoroughly reviewed?

A. Yes. The Company's calculation of avoided cost prices was thoroughly reviewed by the Commission staff in docket UM 1442 in 2009. In Order No. 09-506, the Commission quoted Staff's conclusion that:

> PacifiCorp filed its avoided cost rates using the methodologies required by Order No. 05-584. I further conclude that the prices PacifiCorp used to determine the rates were consistent with the projected market prices available to the company at the time they filed the rates. PacifiCorp calculated their rates without making any arithmetical errors, and the rates that were put into effect are reasonable. In addition, the current rates appear to have been calculated using the same methodologies that were used to determine the previous avoided cost rates that had been in place for two years after being approved in Advice No. 07-021.[4]

Q. Have other states served by the Company recently addressed whether standard avoided cost prices should include fixed capacity payments?

A. Yes. In 2015 the public utility commissions in Utah and Wyoming both approved changes to Schedule 37 rates that included elimination of fixed dollar payments to QFs for capacity costs in favor of spreading capacity costs using the capacity factor of the proxy resource.[5]

Q. What do you recommend with regard to capacity costs in the standard avoided cost prices?

A. The Commission should re-affirm the current rate calculation utilized in the Proxy Method, which has been in place for many years. Proposals to pay a fixed amount to QFs for avoided capacity costs misrepresent the cost of displacing a proxy resource and will further widen the difference between standard avoided cost prices and the costs that can actually be avoided by the utility.

ISSUE 6: DO THE MARKET PRICES USED DURING THE RESOURCE SUFFICIENCY PERIOD SUFFICIENTLY COMPENSATE FOR CAPACITY?

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[4] Docket No. UM 1442, Order No. 09-506 at 4.
[5] Wyoming Docket No. 20000-458-EA-14, Utah Docket Nos. 14-035-55 and 14-035-T04 .

Q. Please describe the calculation of avoided cost prices during the sufficiency period.

A. In Order No. 05-584 in docket UM 1129, the Commission required the Company to use monthly on- and off-peak forward market prices to calculate avoided cost prices when it was in a resource sufficient position,[6] and in Order No. 14-058 the Commission retained this feature of the standard avoided cost prices. The Company is required to use a blend of prices from markets across its system (including the California-Oregon Border, Mid-Columbia, and Palo Verde markets) to calculate the market prices paid during the sufficiency period prices. As a result, avoided cost prices during the sufficiency period reflect the on- and off-peak market value of generation on the Company's system.

Q. Does using market prices during the sufficiency period sufficiently compensate standard QFs for capacity?

A. Yes. Consistent with the Company's IRP, 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. While relying strictly on market prices during the sufficiency period is an oversimplification that is acceptable for standard avoided cost prices, this approach does not precisely represent the Company's avoided costs. As discussed below, sufficiency period avoided costs for non-standard QFs should be calculated using the GRID model to more accurately value the impact of a QF on PacifiCorp's system, including backing down existing thermal resources in addition to avoided market purchases.

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[6] *In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 05-584 at 28 (May 13, 2005).

Q. How are the market prices during the sufficiency period determined?

A. The Company utilizes its latest official forward price curve (OFPC) available at the time avoided cost prices are calculated to determine the market prices during the sufficiency period. The OFPC represents a combination of actual forward prices of electricity gathered from market sources and a model-based forecast of electricity prices based on region-wide loads, resources, and market conditions. The Company issues quarterly OFPCs for use in regulatory filings, business planning, and avoided cost pricing. The OFPC reflects the most current information available at the time it is prepared, is subjected to a rigorous review process by the Company, is available for review by stakeholders, and has been accepted by the Commission for many years as the basis for updating the Company's Transition Adjustment Mechanism (TAM) filings.

Q. What do the market prices used in the sufficiency period represent?

A. The OFPC reflects the price the Company would pay in the market to secure delivery of firm power, with uninterruptible delivery provided according to standard market product definitions (i.e. WSPP Service Schedule C). By definition, this firm market product can be relied on to meet the Company's capacity needs.

Q. Does the Company's IRP rely on market transactions to satisfy its capacity needs?

A. Yes. The Company's IRP calls for Front Office Transactions (FOTs), or short term firm market purchases, to balance the Company's capacity needs. These short-term firm market purchases contribute to meeting PacifiCorp's firm obligation inclusive of a 13 percent planning reserve margin, which ensures the Company has sufficient capacity to maintain reliability at a reasonable cost. In the preferred portfolio selected in the 2013 IRP, short-term firm market purchases rise to over 1,400 megawatts in 2023, the last year before a new major thermal resource is added. The 2013 IRP continues to call for over 1,000 megawatts of FOTs in 2024, despite the addition of a 423 megawatt combined cycle unit and 432 megawatts of wind capacity in that year. Using market prices during the sufficiency period treats these firm market purchases as the avoided capacity resource, which is consistent with the use of firm market purchases in meeting the Company's capacity needs in its IRP.

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. Should the Commission adopt a new method for calculating non-standard avoided cost prices for large QFs?

A. Yes. The Company proposes to calculate non-standard avoided cost prices for large QFs using the PDDRR method, a modeling approach that relies on information from the Company's IRP and measures the impact an individual QF has on the Company's revenue requirement. The PDDRR method is commonly used by the Company in Utah, Wyoming, and Idaho[7] to calculate non-standard avoided cost prices. The Company proposes that the PDDRR replace the current practice of making individual adjustments to the Proxy Method prices for standard avoided costs. Independently calculating the avoided cost of large QFs using the PDDRR method is a more accurate approach for determining the value of the energy and capacity on the

[7] A variation of the PDDRR is used in Idaho called the Highest Displaceable Incremental Cost method, or the IRP Method.

Company's system, taking into account the unique characteristics of each QF.

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

A. No. While it may be helpful to have consistent guidelines for all utilities within a state, utilities should be allowed to employ different production cost models or tailor specific adjustments to match their unique cost structure. The goal when calculating non-standard avoided costs should be to most accurately represent costs that can be avoided by each utility given the characteristics of an individual QF and the circumstances of the utility's system.

Q. How are non-standard avoided cost prices for QFs calculated now?

A. Currently, non-standard avoided cost prices are determined beginning with the Proxy Method used to set standard avoided cost prices, and then making a limited set of discrete adjustments meant to mitigate the recognized deficiencies in the Proxy Method. The current method to calculate non-standard avoided cost prices for large QFs was adopted by the Commission in Order No. 07-360.[8] The list of authorized adjustments was derived from the seven factors outlined in 18 CFR § 292.304(e)(2). In practice, many adjustments identified in 18 CFR § 292.304(e)(2) are interdependent and it is often not possible to calculate a particular adjustment viewed in isolation. The Company's experience in its other jurisdictions is that a differential revenue requirement approach using the PDDRR method is best suited to account for the factors in 18 CFR § 292.304(e)(2).

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[8] *See In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Order No. 07-360, Docket No. UM 1129 (Aug. 20, 2007).

Q. Please provide an overview of the PDDRR method.

A. Under the PDDRR method, the Company performs two simulations using the GRID model to determine the system energy value of a QF resource, taking into account its specific operating characteristics and point of delivery on the Company's system. In addition, the PDDRR method includes avoided fixed costs of the Company's next major resource acquisition, based on the cost and timing of the next deferrable resource in the IRP preferred portfolio. The amount of capacity displaced is determined using the capacity contribution of the QF resource and the avoided fixed costs are spread over the capacity factor of the QF. The timing for including avoided fixed costs from the next deferrable resource is adjusted to account for new QFs (since the IRP was published) that will be on the Company's system at the time the next major resource is acquired. These QFs have either signed a long-term power purchase agreement (PPA) with the Company or have requested avoided cost prices and are actively negotiating a long-term PPA, and will be contractually obligated to deliver power to the Company during future periods when the Company's resource planning indicates a major resource would need to be acquired.

Q. Why is a differential revenue requirement approach more accurate than basing avoided cost prices on a proxy plant?

A. As discussed in previous sections, the Proxy Method is a simplified approach to calculating avoided costs, and the costs that are assumed to be avoided by the Company under the Proxy Method are not always incurred. For example, under the Proxy Method it is assumed that the Company is always able to use the QF output to avoid making market purchases (or make additional market sales) during the resource sufficiency period, and is always able to save the variable cost of the IRP proxy resource during the resource deficiency period. In reality this is not the case. In Order No. 14-058 the Commission acknowledged that "the application of our current [standard rate] methodology may result in the utility and its customers offering prices in excess of actual avoided costs."[9] In that Order, the Commission adopted improvements to the Proxy Method, but did not address the proposed changes to the non-standard method that are needed to accurately calculated the avoided costs of large QFs.

Q. Have you compared the difference in standard avoided cost prices and the PDDRR method?

A. Yes. Table 2 below compares the current standard avoided costs to the PDDRR method using the same vintage of inputs (such as the date of the forward market prices for electricity and natural gas) used in the standard rates.

Table 2

15 Year (2016 - 2035) Nominal Levelized Price at 6.882% Discount Rate ($/MWh)

	PDDRR	Current Sch 37	
		Standard	Renewable
Wind 27.0% CF	$36.64	$40.91	$59.24
Solar 23.6% CF	$37.11	$46.88	$66.54
Thermal 85.0% CF	$43.68	$52.07	$70.40

Q. Does the PDDRR method remedy the deficiencies of the Proxy Method?

A. Yes. The PDDRR method directly measures the impact each QF facility has on the Company's power costs by utilizing the Company's production cost model, GRID, to calculate the value of energy and capacity from QFs based on the unique characteristics of the QF resource and the Company's system. Allowing the GRID

[9] Order No. 14-058 at 7.

model to redispatch thermal resources, including the combined cycle plants from the IRP preferred portfolio, captures the change in operation and costs that occurs with the addition of a QF on the Company's system.

Q. What are the seven factors identified in 18 CFR § 292.304(e)(2)?

A. The Federal Energy Regulatory Commission's (FERC) PURPA regulations found at 18 CFR § 292.304(e)(2) state that the following factors "shall, to the extent practicable, be taken into account" when setting avoided cost prices:

> i) The ability of the utility to dispatch the qualifying facility;
> ii) The expected or demonstrated reliability of the qualifying facility;
> iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirements, and sanctions for non-compliance;
> iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
> v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
> vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
> vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.

Q. In Order No. 07-360, did the Commission prescribe a method to account for each of the seven factors?

A. No. The adjustments adopted by the Commission only reflect two of the seven factors identified in FERC's regulations: i) dispatchability, and ii) reliability. The Commission determined the issues related to iii) contract terms, iv) outages, and v) system emergencies were better addressed in contract provisions rather than as adjustments to avoided costs. The Commission did not adopt any specific framework for addressing vi) the individual and aggregate value of energy and capacity from

QFs on the utility system, or vii) the smaller capacity increments and shorter lead times available from QFs, citing a lack of proposed methods from parties. The Commission did, however, recognize that an adjustment should be made if it can be done in a practical and reasonable way.

Q. Are there additional factors that should also be considered when calculating the avoided cost of energy and capacity of large QFs?

A. Yes. Because large QFs may have specific characteristics that materially impact the value of the energy and capacity on the Company's system, additional factors such as the QF's location, delivery pattern, and capacity contribution need to be considered to accurately calculate its specific value to the Company. Modeling each specific QF in the Company's GRID model allows for these characteristics to be taken into account in the calculation of avoided costs. Furthermore, the two issues left unaddressed by the Commission in Order No. 07-360 – the aggregate capacity of QFs on the Company's system, and smaller capacity increments and shorter lead times available from QFs – are easily accounted for in a modeled approach that recognizes all of the executed and proposed QFs expected to connect to PacifiCorp's system.

Q. What are the components of the avoided cost prices under the PDDRR method?

A. Using the PDDRR method, QF avoided cost prices consist of three main components: avoided capacity costs, avoided energy costs, and integration costs (where applicable).

Q. Please describe how the Company calculates avoided costs of energy under the PDDRR method.

A. The calculation of the avoided energy cost begins with existing and planned resources that represent the Company's most recent IRP resource portfolio. The Company runs two simulations using the GRID model to determine the avoided energy cost. The first simulation (the Base Simulation) calculates net power costs based on the Company's existing resource portfolio and planned resource additions, including signed and potential QFs. The second simulation (the Avoided Cost Simulation) calculates net power costs of the resource portfolio with two modifications: the operating characteristics of the next QF are added with its energy included at zero cost, and the capacity of the next deferrable resource is reduced by an amount equal to the QF's capacity contribution.

This reduction in the capacity of the next deferrable resource is known as partial displacement. Front office transactions are the next avoidable resources partially displaced during the sufficiency period followed by the next deferrable thermal generating resource during the deficiency period. The difference in net power costs between the Avoided Cost Simulation and the Base Simulation equals the avoided energy cost.

Q. Why is the GRID model result a more accurate representation of avoided costs during the sufficiency period than using market prices under the Proxy Method?

A. As described earlier, forward market prices represent the cost of firm power, meaning delivery will occur as scheduled and non-performance is subject to damages. In contrast, generation from a QF is provided on a unit-contingent basis, and the Company must take delivery whether or not the energy is needed to serve load or can be used to avoid market purchases. The Company must also back up QF generation with reserve capacity, requiring that the Company back down its own thermal units.

Simply paying a QF market prices during the sufficiency period does not take these issues into account and overstates the value of QF generation. The most accurate assessment of the costs avoided when a QF delivers power on the Company's system is one utilizing a production cost model, such as GRID, that captures not only the ability to avoid market purchases, but the impact on existing resources and the limitations of the Company's transmission system.

Q. Are the avoided fixed costs of the next deferrable resource included in the PDDRR method during the deficiency period?

A. Yes. The Company calculates the avoided fixed costs of the next deferrable resource outside of the GRID model based on partial displacement of the next major thermal resource acquisition in the IRP (that has not already been displaced by QFs with contracts extending beyond the expected online date of the next major resource). The fixed costs of the deferrable resource as reported in the IRP are adjusted for the capacity contribution of the specific QF type. Because the GRID model results capture the system impacts of displacing the deferrable resource, the avoided fixed costs are converted to a volumetric ($/MWh) rate by spreading them over the QF's expected annual generation.

Q. How do signed and proposed PPAs with other QFs impact the timing of deferrable fixed costs?

A. Signed or proposed PPAs with other QFs serve to partially displace the next major resource acquisition to the extent the QF contracts reach beyond the online date of the next major resource (e.g. 20-year PPAs). As more and more QF contracts are in effect during resource deficient periods, more of the planned resource acquisitions in the IRP are displaced. If a planned resource acquisition is displaced by signed or potential QFs, avoided cost prices for the next QF would include deferred fixed costs only when the Company plans to acquire another major resource.

Q. Please explain what is meant by a "proposed" QF contract.

A. A proposed QF contract is one that has begun the process required to enter into a PPA with the Company, but for which a signed contract has not yet been executed. At the time a new QF in Oregon submits a request to receive indicative avoided cost prices, there may be dozens of other projects (in Oregon or in any of the other states served by PacifiCorp) that have also already requested prices and started down the path of executing a PPA.

Under the current non-standard method, each QF is assumed to displace the next major resource in the Company's IRP regardless of the amount of capacity that will be provided by PPAs with other QF resources already proposed and/or signed. In other words, under the current method each new QF is priced as if it was the only QF project to request prices. All other proposed QF projects are ignored even though they too are seeking PURPA contracts. Recognizing proposed QFs appropriately accounts for the individual and aggregate value of energy and capacity from QFs on the electric utility's system as required by PURPA.

Q. How many QFs are currently proposed to connect to the Company's system?

A. In the Company's application filed May 21, 2015, requesting a reduction in the eligibility cap for standard avoided cost prices and a reduction to the maximum allowable contract term of QF contracts, Company witness Bruce Griswold explains that the Company currently has requests for over 4,000 MW of new PURPA contracts system-wide.

Q. What is the effect on avoided costs if proposed QF projects are recognized when calculating prices for the next QF?

A. Recognizing additional long-term QF PPAs with terms extending into the resource deficiency period delays the timing of fixed costs that can be avoided by the next QF. Absent this recognition, customers may pay QFs for the same deferred resource several times over. Even after adjusting for capacity contributions calculated in the 2013 IRP, a queue of potential QFs as large as exists for PacifiCorp will fully displace the 2024 CCCT from the 2013 IRP and should delay recognition of avoided fixed costs to coincide with the next major resource acquisition in 2028. In addition to delaying avoided fixed costs, each successive QF displaces lower and lower cost existing resources in the Company's portfolio, resulting in lower avoided cost prices.

Table 3 below demonstrates the difference in avoided costs if potential QF contracts are ignored. The PDDRR results were first calculated including all signed and potential QFs in the model. Then, all potential QFs were removed from the model, resulting in an increase in the avoided costs.

Table 3

15 Year (2016 - 2035) Nominal Levelized Price at 6.882% Discount Rate ($/MWh)

	PDDRR	
	Potential and Signed QFs Included	Only Signed QFs Included
Wind 27.0% CF	$36.64	$39.88
Solar 23.6% CF	$37.11	$48.46
Thermal 85.0% CF	$43.68	$49.29

Q. Should inputs to the production cost model runs used for the PDDRR method be updated more frequently than done for standard avoided costs?

A. Yes. An accurate determination of non-standard avoided cost prices requires a more involved calculation than the Proxy Method, and merits the use of updated inputs. In order for retail customers to be indifferent to the calculated avoided cost prices, the underlying assumptions and modeling inputs must be based on the best information available at the time the QF pricing is prepared. Accordingly, all modeling inputs in the PDDRR method should be subject to update, including but not limited to the forecast of wholesale market prices for electricity and natural gas, executed purchase and sale contracts, wheeling contracts, coal contracts, and the retail load forecast. The resource additions outlined in the IRP preferred portfolio should be updated with a new IRP or IRP update, or if there is a known change to the IRP action plan, such as a delay or abandonment of a resource addition that causes a change to the preferred portfolio.

Q. Are there similarities between developing avoided cost prices for QFs and preparing the transition adjustment for direct access customers in Oregon?

A. Yes. While one addresses the impact of adding a resource to the system and the other addresses removing load from the system, they both involve tradeoffs between simplicity (proxy approach) and accuracy (production cost model-based approach). The Commission addressed these issues with respect to the transition adjustment in dockets UM 1081 and UE 179. In docket UM 1081, the Commission adopted an interim transition adjustment (proxy approach) for the near-term, but asked parties to work together to find a long-term solution. Subsequently, in docket UE 179, the

Commission rejected the proxy approach in favor of using differential GRID runs to value the loss of the direct access load. In this case, the Company is asking the Commission to apply the differential GRID run method found prudent for valuing lost load to the acquisition of new QF resources.

Q. What policy direction did the Commission provide in docket UM 1081?

A. The Commission stated: "Ideally, a transition adjustment will value utility resources impacted by direct access based on actual, appropriate operational responses."[10] This could just as easily apply to avoided costs where, ideally, avoided cost prices will value utility resources impacted by QF resource additions based on actual, appropriate operating responses. The Commission said that its goal was to develop a transition adjustment that values resources on PacifiCorp's actual operational responses based on appropriate planning.[11] Again, this could just as easily apply to avoided cost prices where it would be desirable to develop avoided cost prices that value resources on PacifiCorp's operational responses based on appropriate planning.

Q. What did the Commission conclude in docket UE 179 after setting forth policy direction in docket UM 1081?

A. The Commission found that using the differential GRID run approach to determine the transition adjustment proposed by PacifiCorp most closely met the requirements established in Order No. 04-516 in docket UM 1081.[12] The Commission went on to say, "The purpose of the TAM is not to promote direct access, as ICNU would have us do. Rather, the TAM is to capture costs associated with direct access, and prevent

[10] Docket No. UM 1081, Order No. 04-516, page 10.
[11] Docket No. UM 1081, Order No. 04-516, page 12.
[12] Docket No. UE 179, Order No. 05-1050, page 21.

unwarranted cost shifting."[13] This policy direction can be directly translated to avoided cost pricing, where the purpose of QF pricing is to capture costs avoided by adding QFs to the system and prevent unwarranted cost shifting. There is no basis for sacrificing accuracy in the development of avoided cost prices for large QFs.

The Company urges the Commission to adopt a GRID-based approach to set avoided costs going forward as this would offer the most precise and accurate accounting of the impact that a new QF resource is likely to have on PacifiCorp's operations, costs and revenues.

Q. Since docket UE 179, has the Commission re-affirmed the use of GRID to model the transition adjustment and rejected a straight market-price approach?

A. Yes. In docket UE 245, the Commission rejected a proposal to use market prices instead of GRID to calculate the transition adjustment.[14] In that case, the Commission found that the use of only forecast market prices "may not accurately reflect an actual estimate of direct access costs, because Pacific Power's utility operations are complex and multidimensional."[15]

Q. In calculating the transition adjustment, has the Commission consistently rejected a credit for avoided transmission costs, supporting the Company's position on Issue 1, discussed above?

A. Yes. The Commission expressly rejected proposals to add a credit to the transition

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[13] *Id.*
[14] *In the Matter of PacifiCorp dba Pacific Power 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 (Oct. 28, 2013).
[15] *Id*. at 12-13 (internal quotations omitted).

adjustment for avoided transmission costs in PacifiCorp dockets UE 245 and UE 264.[16]

Q. Does this conclude your direct testimony?

A. Yes.

[16] *In the Matter of PacifiCorp dba Pacific Power 2013 Transition Adjustment Mechanism*, Docket UE 245, Order No. 12-409 at 17 (Oct. 29, 2012), *aff'd on reconsideration*, Order No. 13-008 (Jan. 15, 2013); Order No. 13-387 at 13-14.

Docket No. UM-1610
Exhibit PAC/900
Witness: Ted Drennan

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Opening Testimony of Ted Drennan

May 2015

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PURPOSE AND SUMMARY OF TESTIMONY 1

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Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name Ted Drennan. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Integrated Resource Plan (IRP) Program Manager.

QUALIFICATIONS

Q. Briefly describe your education and business experience.

A. I have a BS in Economics from the University of Wyoming and have completed the coursework for a Master of Science in Regulatory Economics. I have worked for PacifiCorp (the Company) since 2013. Prior to PacifiCorp I worked for Portland General Electric in various departments including the IRP, and Rates and Regulatory Affairs group for eleven years. Other utility experience includes employment at two consulting firms as well as the Iowa Office of Consumer Advocate.

My current responsibilities as IRP Program Manager include managing the IRP public and regulatory processes, preparing the IRP filings consistent with applicable state IRP guidelines and requirements, and tracking progress toward meeting IRP action items. I have appeared as a witness before the Public Utility Commission of Oregon (Commission) previously in multiple proceedings, including dockets specific to Qualifying Facility (QF) issues.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony addresses Issue 5 listed in Attachment A – UM 1610 Phase II Issues

List as included in Administrative Law Judge Traci Kirkpatrick's March 26, 2015, Ruling: What is the appropriate forum to resolve litigated issues and assumptions?

Q. Please summarize your testimony.

A. The IRP is the proper forum to establish modelling assumptions used for determination of the characteristics of the costs and timing of a utility's avoided resource. As the Commission has repeatedly acknowledged, it is appropriate for the Company to rely on inputs and assumptions developed in an acknowledged IRP when setting avoided cost prices. The Company's IRP is developed as part of a robust and transparent public process where the Company solicits, and addresses, comments from Commission staff and stakeholders. In addition to setting avoided cost prices, IRP results are relied upon in other regulatory contexts.

The IRP public process is the preferred forum to consider issues and assumptions that are fed into the avoided cost filings. It is a well-vetted and transparent process that allows for input from stakeholders and the Commission. Allowing parties additional opportunities to challenge IRP inputs and assumptions in avoided cost contested cases would disrupt the IRP's usefulness by potentially unwinding the selection and timing of lowest-cost/least-risk resources, the resource sufficiency/deficiency demarcation, and the utility's IRP action plan.

Q. Please describe an IRP.

A. The Commission's rules define an IRP as:

> [T]he energy utility's written plan … detailing its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives to

> meet those needs, and its action plan to select the best portfolio of resources to meet those needs.[1]

Q. Do the Commission's IRP guidelines specify the need for significant stakeholder involvement when utilities prepare their long-term resource plans?

A. Yes. IRPs are developed in a robust and transparent public process. The Commission established the procedural and substantive requirements of least-cost planning in 1989.[2] One of the key procedural requirements the Commission identified was "[s]ignificant public and other utility involvement in plan preparation."[3]

In Order No. 07-002, the Commission established the majority of IRP Guidelines that are currently in use. The IRP procedural requirements contained in Guideline 2a mandates robust public involvement in the IRP planning process:

> The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.[4]

Q. Please describe the public input and review process PacifiCorp uses while developing its IRP.

A. The Company recognizes that the public input process is a critical element in the development of the IRP. As such, the Company pursues an open and collaborative approach. Using the 2015 IRP process as an example, the Company provided

[1] OAR 860-027-0400(2).
[2] *See* Order No. 89-507 (Apr. 20, 1989).
[3] Order No. 89-507.
[4] *See* Docket No. UM 1056, Order No. 07-002, Appendix A page 2 of 7 (Jan. 8, 2007).

numerous opportunities for stakeholders to provide meaningful input to a broad range of IRP planning steps. Prior to beginning its 2015 IRP, the Company held a workshop to solicit feedback on potential improvements to the IRP process. In June 2014, PacifiCorp met with Oregon IRP stakeholders to discuss any item of their choosing related to PacifiCorp's IRP. The 2015 IRP public process included seven public input meetings held jointly in Portland and Salt Lake City via teleconference and the Company hosted two technical workshops.[5] Through any number of these meetings and workshops, along with direct feedback to the Company, participants have the opportunity to review and influence the Company's IRP model assumptions, studies, methodologies, and results. Suffice it to say the Company is diligent in soliciting and incorporating public input when performing its long-term resource planning activities.

Q. Do the Commission's IRP guidelines allow for parties to provide input on an IRP outside of the Company's public process discussed above?

A. Yes. Guideline 3 (Plan Filing, Review, and Updates) specifically addresses the regulatory process for IRPs. Guideline 3c allows for comments and recommendations by "Commission Staff and parties."[6] Guideline 3d requires the Commission to consider public comments and recommendations when considering acknowledgement. Further, the guidelines grant the Commission flexibility when providing direction to the utility for future IRP analyses or actions.[7]

Q. How long has the IRP played a role in setting avoided costs?

A. Because the IRP's robust public input and review process generates accurate and

[5] See Appendix C of PacifiCorp's 2015 IRP for further details on the public input process.
[6] Order No. 07 002, Appendix A at 3.
[7] *Id.*

reliable information, the Commission has tied avoided costs to least cost planning (the precursor to IRP) since 1992. In Order No. 92-1793, the Commission "consolidate[d] the avoided cost process with least-cost planning schedule."[8] That order imposed the obligation now found in OAR 860-029-0040(4)(a) to file avoided cost updates within 30 days of IRP acknowledgement.[9]

Q. Has the Commission recently commented on the use of IRP inputs and assumptions in avoided cost calculations?

A. Yes. The Commission has repeatedly affirmed that the IRP inputs, which are subject to stakeholder review, are appropriate for use in developing avoided costs. As the Commission most recently stated in Order No. 14-058 from docket UM 1610:

> Calculation of each utility's standard avoided costs begins with the utility filing an IRP for a 20-year planning horizon, as required every two years. Utilities' avoided cost methodologies were designed to capture the avoided costs actually realized by the utility when it purchases power from a QF, and are intended to be simple and clear, with inputs and assumptions taken from IRPs that are subject to stakeholder review.[10]

Q. What assumptions in the IRP are used in setting avoided cost rates?

A. Many items incorporated in the IRP and reviewed in the planning process can directly or indirectly impact avoided cost prices. A subset of these IRP inputs include: resource sufficiency period, fuel forecasts, capacity contribution rates, and wind integration costs as well as the cost and performance of specific resources.

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[8] Order No. 92-1793 at 2.

[9] At the time, the obligation was codified in OAR 860-029-040(a) and stated:

> Each public utility shall file with the Commission, within 30 days of Commission acknowledgment of its least-cost plan pursuant to Order No. 89-507, to become effective 30 days after filing, standard rates for purchases from [QFs].

[10] Docket No. UM 1610, Order No. 14-058 at 12 (Feb. 24, 2014).

Q. Please explain how resource sufficiency and deficiency periods are defined and the impact on the avoided costs.

A. The resource sufficiency/deficiency demarcation is based on the first avoidable resource as indicated in a utility's IRP. The determination of the resource sufficiency period impacts QF pricing by influencing when the next major resources can be avoided. The beginning of the resource deficiency period is the point when the fixed capacity costs of the avoided resource are included in avoided cost prices. When a utility is resource sufficient, QF purchases may displace existing utility-owned generation, or market purchases. When a utility is resource deficient, however, avoided cost prices reflect the capacity contribution of QF projects.

Q. Are the resource sufficiency and deficiency periods the same for renewable and non-renewable resources?

A. They demarcation points may be the same for both renewable and non-renewable resources, but are not constrained as such. The Commission set a separate avoided cost rate for renewable resources in Order No. 11-505. In the order they determined the IRP was the proper place to determine renewable resource sufficiency with sufficiency prices based on market, and deficiency prices based on the "the next utility scale renewable resource acquisition in the utility's IRP."[11] Therefore it is possible to have different sufficiency and deficiency periods for differing classes of resources.

Q. Has the Commission indicated it is satisfied with using the IRP for determination of resource sufficiency?

A. Yes. In Order No. 10-488, the Commission stated:

[11] Docket No. UM 1396, Order No. 11-505 at 4 (Dec. 13, 2011).

> We agree that the IRP process is the appropriate venue for addressing resource sufficiency/deficiency issues because the IRP processes are conducted with extensive public review regarding the timing of the utility's loads and its consequent resource needs. We acknowledge, however, that further guidance is necessary to make the IRP process more workable for this purpose. We provide that guidance here.
>
> Where the utility's acknowledged IRP shows a range of on-line years for a major resource, we find that the earliest date in the range will set the date for resource deficiency. By selecting the earliest date, the utility is provided a meaningful incentive to accurately predict the timing of its resource needs. If an earlier date than necessary were chosen, the utility would pay higher avoided costs during a resource sufficient period.[12]

The Commission reaffirmed this conclusion in Order No. 11-505, stating:

> As noted by Pacific Power, we earlier found the IRP process to be the appropriate venue for determining when a utility is resource sufficient or deficient. The derivation of a renewable avoided cost fits well within the same framework and allows issues relating to resource sufficiency or deficiency to be addressed as part of an integrated whole. The IRP preferred portfolio and Action Plan provide the basis for deciding when a renewable resource would be avoided by QF purchases.[13]

Order No. 11-505 clearly states that the Commission finds the IRP the proper vehicle for determining when a resource is avoidable:

> **G. When is a planned resource acquisition avoidable? (Issue C)**
>
> We resolved this issue above by concluding that the IRP Action Plan should be used to decide when a planned resource acquisition is avoidable.[14]

Q. How does the resource sufficiency determination impact avoided costs?

A. As mentioned above, a utility that is resource sufficient can only avoid market purchases or displace utility-owned generation when making QF purchases. The

[12] Docket No. UM 1396, Order No. 10-488 at 8 (Dec. 22, 2010).
[13] Docket No. UM 1396, Order No. 11-505 at 6 (Dec. 13, 2011).
[14] *Id.* at 10.

Commission recognized that the price paid in the sufficiency period should be tied to market rates, as shown in Order No. 11-505:

> Like standard avoided costs, the renewable resource avoided cost rates will vary depending on whether the utility is renewable resource sufficient or deficient. During periods of renewable resource sufficiency, the rate should be based on market prices. During periods of deficiency, we adopt Pacific Power's proposal to base the renewable avoided cost on the next utility scale renewable resource acquisition in the utility's IRP. We find that reference to the utility's IRP will best ensure that the renewable resource avoided cost rate most accurately reflects the costs the utility will avoid with the QF purchase.[15]

The passage above also recognizes that there may be different sufficiency periods dependent on the resource type (i.e., renewable or non-renewable resources).

Q. Has the Commission endorsed the use of IRP gas forecasts when setting avoided cost prices?

A. Yes. The Commission recognized in Order Nos. 05-584 and 06-538 that utilities will legitimately have different approaches to gas forecasts and declined to adopt a single gas forecast for all utilities to use.[16]

Q. Has the Commission endorsed the use of IRP wind integration studies and capacity contribution studies for use in calculating avoided cost prices?

A. Yes. The IRP contains both a wind integration study and a capacity contribution study. In Order No. 14-058, the Commission endorsed the use of inputs from an acknowledged IRP when determining avoided costs. The Commission concluded that renewable avoided cost prices should reflect wind integration costs set out in an acknowledged IRP:

> First, for a wind QF located inside a contracting utility's

[15] Order No. 11-505 at 4.
[16] Docket No. UM 1129, Order No. 05-584 at 36 (May 13, 2005) and Order No. 06-538 at 44 (Sept. 20, 2006).

> Balancing Authority Area (BAA), under our Standard Method the integration costs that the wind facility imposes on the contracting utility will be subtracted from the Standard Method avoided cost rate, using the wind integration cost estimates produced in the utility's most recently acknowledged utility IRP or IRP update.[17]

The Commission similarly concluded that renewable avoided cost prices should reflect the contribution to capacity identified in an acknowledged IRP:

> We agree on the need to adjust for capacity contribution of each resource type and adopt Staffs 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.[18]

Q. Are avoided cost updates tied to the IRP cycle?

A. Yes. The Commission has tied avoided cost updates to least cost planning, the precursor to the IRP since 1992. In Order No. 92-1793, the Commission "consolidate[d] the avoided cost process with the least-cost planning schedule."[19] That order imposed the obligation now found in OAR 860-029-0040(4)(a) to file avoided cost updates within 30 days of IRP acknowledgement.[20]

The Commission reaffirmed the connection between the IRP process and avoided cost updates in Order No. 14-058. In that order, the Commission instructed utilities to update avoided costs of May 1st of each year, but retained the requirement to update avoided cost prices within 30 days after acknowledgement of an IRP. The requirement to update promptly after acknowledgement of an IRP clearly demonstrate

[17] Order No. 14-058 at 14.
[18] *Id.* at 15.
[19] *Id.* at 25-26.
[20] At the time, the obligation was codified in OAR 860-029-040(a) and stated: "Each public utility shall file with the Commission, within 30 days of Commission acknowledgment of its least-cost plan pursuant to Order No. 89-507, to become effective 30 days after filing, standard rates for purchases from [QFs]." Order at 11.

that the exhaustive IRP process generates well-vetted and reliable inputs and assumptions that are suitable for use in avoided price calculations. If the Commission did not trust the results of the IRP process, it would not have directly tied avoided cost updates to the IRP results. The Commission also expressed its confidence in IRP inputs when it stated that it would continue to allow mid-cycle IRP updates based on “significant changes” but clarified that such changes would be subject to a “very high” bar.

Q. What are the issues that would arise if IRP assumptions were litigated in a separate avoided cost process?

A. A process whereby stakeholders could litigate inputs and assumptions developed in an acknowledged IRP would cause multiple problems. First and foremost, as described above, the IRP is a well-established, thoroughly-vetted long-term planning process. This process ends with the development of a preferred portfolio and an action plan for the next two to four years. Individual assumptions are important to the selection of the IRP preferred portfolio and the associated action plan. Introducing a separate process to litigate specific assumptions would be duplicative and could potentially invalidate the IRP public input process.

The Company views the public input process as a valuable tool in soliciting stakeholder feedback before the IRP is finalized and filed with its state commissions. This interaction could be compromised if IRP parties become less inclined to participate in the public process knowing there will be a separate process after the IRP is filed to litigate specific IRP assumptions, which in turn, could influence the IRP outcome. Moreover, a separate process to litigate IRP assumptions is in conflict with planning principals seeking transparency and public involvement. In effect, utilities would be asked to openly and publicly discuss assumptions and methodologies knowing that they will later be litigating those same issues again in a redundant proceeding with potentially the same parties. This second, duplicative process would start thirty days following the Commission acknowledgement of an IRP, i.e. with the updated avoided cost filing.

Q. Do you have any other concerns with introducing a separate process to litigate IRP assumptions?

A. Yes. A separate process to litigate IRP assumptions would duplicate efforts and slow the process for setting avoided cost prices. Stakeholders and regulators have opportunities for input to the IRP while it is being developed. Once the IRP is filed there is a six-month comment period, which frequently extends longer. Parties have an opportunity to review and comment on inputs to avoided costs throughout the entire IRP process, and the Company and the Commission take those comments into consideration in development and acknowledgment of the IRP. Further litigation of IRP inputs and assumptions in an avoided cost contested case proceeding would simply rehash the issues with little to no additional benefit.

Q. Could a process for litigating IRP inputs and assumptions as part of avoided cost updates delay the implementation of price updates?

A. Yes. The Company is concerned that parties could leverage the process to slow down avoided cost updates by litigating IRP inputs as a means to extend the effective date, particularly when price updates are going down. When the Company has proposed lower avoided cost prices, it has seen a flurry of last-ditch power purchase agreement

(PPA) requests seeking to lock in stale prices. For example, when the Company filed avoided cost updates in April 2014, the Company received numerous PPA requests; in fact, some QFs simply downloaded the Company's Schedule 37 PPA from the Pacific Power website, executed the PPA, and submitted it without any prior contact with the Company. 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.

CONCLUSION

Q. Please summarize your recommendation.

A. For the reasons discussed above it is clear that the IRP is the preferred forum to consider issues and assumptions that are fed into the avoided cost filings. It is a well-vetted and transparent process that allows for input from stakeholders and the Commission. Allowing parties to litigate IRP inputs and assumptions in avoided cost contested cases would disrupt the IRP's usefulness by potentially unwinding the selection and timing of lowest-cost/least-risk resources, the resource sufficiency/deficiency demarcation, and the utility action plan.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UM-1610
Exhibit PAC/1000
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Opening Testimony of Bruce W. Griswold

May 2015

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Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Bruce W. Griswold. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am employed by PacifiCorp as Director of Short-Term Origination and Qualifying Facility (QF) Contracts.

QUALIFICATIONS

Q. Briefly describe your education and business experience.

A. I have a B.S. and M.S. degree in Agricultural Engineering from Montana State University and Oregon State University, respectively. I have been employed by the Company for over 25 years in various positions of responsibility in retail energy services, engineering, marketing and wholesale energy services. I have also worked at an environmental firm as a project engineer.

My current responsibilities as Director of Short-term Origination and QF Contracts include the negotiation and management of wholesale power supply and resource acquisition through requests for proposals as well as overall responsibility for the Company's QF power purchase agreements (PPA). I have appeared as a witness on behalf of the Company in docket UM 1610 Phase I and in multiple proceedings across the Company's six state jurisdictions.

PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony responds to three issues from the docket UM 1610 Phase II Issues List in Attachment A of the March 26, 2015 Ruling by Administrative Law Judges Shani Pine and Traci A.G. Kirkpatrick:

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?

Issue 8 – When is there a legally enforceable obligation?

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. Are any other Company witnesses presenting testimony in Phase II?

A. Yes. Mr. Brian S. Dickman, Director, Net Power Costs and Load Forecasting, presents testimony for the Company regarding avoided cost methodology and pricing. Specifically, Mr. Dickman addresses issues 2, 3, 4, 6, and 7 from the docket UM 1610 Phase II Issues List. Mr. Ted Drennan, PacifiCorp's Integrated Resource Plan (IRP) Program Manager, addresses issue 5 related to the forum for resolving litigated issues and assumptions used when developing avoided cost prices.

Q. Please summarize your testimony.

A. I have summarized the Company's position on each of the issues below.

- *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?* The Company makes one correction to the question that defines Issue 1, by noting that the Schedule 37 PPA is not a 20-year fixed price contract. The Schedule 37 PPA currently has a contract term of up to 20 years of which the first 15 years are available at fixed avoided cost prices and the last five years are at market prices.[1] The Company's position is that a renewable Schedule 37 PPA is based on avoidance of the renewable proxy by the QF, and at the point in time

[1] The Company addresses the contract term issue in a separate filing made with the Commission.

that the resource deficiency period starts through the end of the PPA, the Green Tags[2] should go to the Company consistent with the avoidance of that renewable resource.

- *Issue 8. When is there a legally enforceable obligation?* The Company recognizes that the issue of a legally enforceable obligation involves many legal questions and proposes that the Commission set criteria for establishing a legally enforceable obligation using the milestone of the QF approving the final draft PPA as contemplated in B(5) on page 10 of Schedule 37.[3]
- *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?* In Phase I of this proceeding, the Commission determined that QFs are responsible for any third-party transmission costs associated with moving the QF's output from a load pocket (i.e., an area where there is insufficient load to absorb the QF's output) to another load area on the utility's system. All costs and benefits of third-party transmission service should be attributed to the individual QF and should be reflected as an adjustment to the avoided cost price or as a contractual adjustment to billing in the PPA.

[2] In my testimony, I will also refer to Green Tags as Renewable Energy Credits or RECs.
[3] While the focus of my testimony on Issue 8 is toward Schedule 37, the testimony is meant to be inclusive of Schedule 37 and Schedule 38 QF contracts.

ISSUES

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. What is the background for this issue?

A. Order No. 05-584 states that the QF shall receive a contract term of up to 20 years in which fixed avoided cost prices are used for the initial 15 years, and at the option of the QF, market prices are used for the last five years. In its order, the Commission explains its rationale for this structure:

> [W]e acknowledge that 20 years is a significant amount of time over which to forecast avoided costs. Indeed, divergence between forecasted and actual avoided costs must be expected over a period of 20 years. Given our desire to calculate avoided costs as accurately as possible, and the testimony of several parties that avoided costs should not be fixed beyond 15 years, we are persuaded that standard contract prices should be fixed for only the first 15 years of the 20-year term. Tariffs and standard contract terms should provide that, in the event a QF opts for a standard contract with a 20-year term, the QF must take one of the market pricing options that we address later in this order for the final five years of the contract.[4]

Order No. 05-584 was issued in 2005 when the QF retained 100 percent of the Green Tags, and there was no dispute regarding the Green Tag ownership when the Company went from resource sufficiency to resource deficiency. While this seems like a straight-forward approach, the dispute arises when interpreting Order No. 05-584 in docket UM 1129 and Order No. 11-505 in docket UM 1396 together. In Order No. 11-505 the Commission provided a QF with "the option of choosing between the renewable resource QF rate—likely to be based on a wind resource—or the standard QF rate based on the

[4] Order No. 05-584, docket UM 1129 at 19.

CCCT proxy."[5] The Commission also ordered that when selecting a renewable resource rate, the QF would retain the Green Tags during the resource sufficiency period and the utility would get the Green Tags during the resource deficiency period or at the point in time when the proxy renewable resource would have been constructed. Order No. 11-505 reads:

> During periods of renewable resource sufficiency, the rate will be based on market prices. During periods of renewable resource deficiency, the rate will be based on the renewable avoided cost of the next utility scale renewable resource acquisition in that utility's IRP. The renewable resource QF will keep all associated Renewable Energy Certificates (RECs) during periods of renewable resource sufficiency, but will transfer those RECs to the purchasing utility during periods of renewable resource deficiency.[6]

Q. Please describe the Schedule 37 pricing structure for QF choosing a renewable rate option.

A. The current approach for calculating Oregon Schedule 37 avoided cost prices relies on fixed market prices during the resource sufficiency period and the cost of the next avoidable resource identified in the Company's IRP during the period of resource deficiency (Proxy Method). So a QF that selects a 20-year Schedule 37 contract would receive a PPA with fixed prices for the initial 15-year term and market prices for the remaining 5-year term. The prices paid during 15-year fixed price term would be based on the then-current resource sufficiency and deficiency period defined by the most recent acknowledged IRP and the applicable Commission-approved Schedule 37 rate.

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[5] *In the Matter of Public Utility Commission of Oregon Investigation Into Resource Sufficiency Pursuant to Order No. 06-538*, Order No. 11-505, docket UM 1396 Phase II at 5 (December 13, 2011).
[6] Order No. 11-505, docket UM 1396 Phase II at 1 (December 13, 2011).

Q. How is this structure inconsistent with current Commission rules for Green Tag ownership?

A. For a renewable resource, the sufficiency/deficiency demarcation may be different than the timing for the first deferrable thermal resource identified in the IRP. During the 15-year fixed price term, the QF would receive a fixed market price for the resource sufficiency period and retain the RECs. At the demarcation of the resource deficiency period, defined by the point in time when the proxy renewable resource would have been constructed, the QF begins to receive the fixed avoided cost prices based on the renewable proxy resource and the RECs are transferred to the Company.

For example, assume a QF's scheduled commercial operation date is January 1, 2017.[7] Also assume that the resource deficiency period begins in January 1, 2024, and the QF has selected a 20-year contract term. The QF's 15-year fixed price term begins January 1, 2017, and ends December 31, 2031. For years 2017 through 2023, the QF receives fixed market prices as published in Schedule 37 and retains the RECs. Beginning in 2024 through 2031, the QF receives the fixed avoided cost prices based on the avoided resource and transfers the RECs to the Company. Then beginning in 2032, the QF starts the market index portion of its 20-year contract, however the resource deficiency period has not changed. The published Schedule 37 rates still shows fixed avoided cost prices in years 2032 and beyond. So for the QF who is beginning the 5-year market price term, only the pricing mechanism has changed in compliance with Order No. 05-058, moving the QF to market prices. This

[7] For simplicity, in this example I use the scheduled commercial operation date as the start date of the contract for determining term length.

is not based on a change in sufficiency/deficiency but based only on the Commission's decision to limit fixed prices to 15 years.

Q. How should the Green Tag ownership issue be resolved?

A. It was clear from Order No. 11-505 that the Company would receive the Green Tags through the resource deficiency period or going forward from the point in time that the Company had identified a need for a new renewable resource in its IRP used to set the Schedule 37 avoided cost prices. It is also clear that the purpose of contract term as established under Order No. 05-584 was to promote QF financing, not to establish a return to resource sufficiency because of a QF's voluntary option to accept market prices during the last five years of a PPA. Therefore, the Company's position is that the Green Tags should be awarded to the utility upon the beginning of the resource deficiency period as established by the IRP and documented in Schedule 37 for the remainder of the QF contract term.

It should also be noted that the QF does not have to agree to a term of 20 years and can opt for a 15-year fixed price term and retain Green Tags during the resource sufficiency period. In fact the Company is seeing more and more Schedule 37 QFs seeking a 15-year fixed price term and not taking on the market risk in the backend years.

ISSUE 8: WHEN IS THERE A LEGALLY ENFORCEABLE OBLIGATION?

Q. Why has legal enforceable obligation (LEO) become an issue[8]?

A. There are a couple of major drivers for QFs seeking a LEO with the Company, the first being declining avoided cost prices and the second is a major ruling by a state

[8] While the focus of my testimony on legal enforceable obligation in Issue 8 is toward Schedule 37 QF contracts, the testimony is meant to be inclusive of Oregon Schedule 37 and Schedule 38 QF contracts.

commission on QF contract terms and eligibility criteria. During times of rising avoided cost prices, the majority of QFs will seek new PPAs or seek to renew existing PPAs after the price change has occurred unless there is some other milestone they need to achieve such as incentive funding or a tax credit deadline. When avoided cost prices are falling and a price change is going to occur in the near future, or a Commission decision is pending that will adversely affect the QF, the requests for QF PPAs and declaration of LEOs for their projects become frenzied.

In the Company's experience, QFs have attempted to establish a LEO by several means. When everything is done on a timely fashion (as is contemplated by the timeline in the Company's Commission-approved Schedule 37) with no forced deadlines, the Company and the QF establish a line of communication, the QF provides the requested and necessary information for the Company to prepare a draft PPA, the draft PPA is exchanged, and then the PPA is finalized and executed. This is typically a 90 to 120 day process. When a drop in avoided cost prices is known or anticipated, the process can be considerably different, as demonstrated by examples outlined below.

First, on August 18, 2014, just one day before the Company's updated avoided cost prices were approved by the Commission, the Company received two unilaterally executed Schedule 37 QF PPAs where the QF simply downloaded the Company's form PPA from the internet, filled it in, signed it, and sent it to the Company. The Company had no communication with the developer prior to receiving the PPAs in the mail, and no knowledge of the project details. The developer nonetheless claimed that its unilateral actions resulted in a LEO.

In the second case, a QF sent a letter to the Company days before the avoided cost update was to become effective and indicated that it was willing and able to enter into a PPA immediately (with no prior negotiations or discussions). Again, the developer claimed its actions established a LEO.

Finally, in Idaho, a QF developer who had submitted multiple requests for non-standard solar QFs PPAs[9] delivered to PacifiCorp executed QF contracts that it had downloaded from Idaho Power Company, filled in avoided cost prices from an approved Idaho Power solar QF contract, substituted PacifiCorp's name for Idaho Power, and sent to the Company on the day that the Idaho Commission approved an interim term of five years for QFs. The developer claimed it had a LEO for not only a 20-year term but for the Idaho Power avoided cost prices (not the Company's). While these three examples may be viewed as extreme cases, they are happening with more frequency and in larger numbers than in the past because avoided cost prices are currently declining. These examples demonstrate attempts by developers to exploit the lack of specific criteria to establish a LEO under state law.[10]

If the utility incurs fixed-price purchase obligations upon the occurrence of a LEO, and customers incur a corresponding obligation to pay for QF power, more than mere verbal or written representations about being willing and able to sign a PPA should be required before the QF obtains the benefits of a LEO (and the attendant avoided cost prices or other contract terms). The Commission should establish, consistent with its obligations to implement Public Utility Regulatory Policies Act of

[9] In Idaho, a solar or wind QF over 100 kW must have individual indicative prices for its projects prepared versus using standard avoided cost prices approved by the Idaho Commission.

[10] *Grouse Creek*, 142 FERC ¶61,187, at P 41 (March 15, 2013) ("We recognize that 'it is up to the States, not this Commission, to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law") (emphasis added).

1978 (PURPA) regulations as promulgated by the Federal Energy Regulatory Commission (FERC), specific criteria a QF must satisfy in order to establish that it has "commit[ed] itself to sell all or part of its electric output to an electric utility" as required by FERC.[11] A bright-line test will provide certainty for developers and utilities alike, and will reduce the number of disputes around LEO formation.

Q. Do you expect controversy around the LEO issue to continue if strong, clear, and balanced guidelines are not established?

A. Absolutely. As of May 1, 2015, the Company has forty Schedule 37 and Schedule 38 requests totaling 587 MW of nameplate capacity. Exhibit BWG - 1 provides detailed information on the Oregon Schedule 37 and Schedule 38 PPA and pricing requests, including size (nameplate capacity), type (i.e. solar, wind), and proposed online date. Project names have been withheld to maintain confidentiality of developer information.

When this data is overlaid with the number of recent QF contracts declaring a LEO for specific vintage avoided cost prices, it is an alarming percentage. A total of 20 QF projects claimed a LEO to secure the pre-August 20, 2014[12] avoided cost prices. The Company is still evaluating these QF contracts based on their LEO declaration but has not executed any contracts as of this filing. Those QFs have not withdrawn their project requests but their QF PPA request submittals were lacking fundamental project and contract details that I will discuss later. The Company is now once again facing this same situation with our recent May 1, 2015, Schedule 37 avoided cost price update filing and have an additional fifteen Schedule 37 QF

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[11] *Grouse Creek*, 142 FERC ¶61,187 at 36.

[12] The Oregon Commission issued an order approving a Schedule 37 avoided cost price change on August 20, 2014.

contract requests totaling 135 MW; all seeking the current Schedule 37 avoided cost prices before they change June 1, 2015[13]. This dramatic increase in PURPA contract and pricing requests in Oregon was not anticipated or considered when the Commission previously addressed QF issues in docket UM 1129 and Phase I of this docket, and demonstrates the need for specific LEO criteria to provide certainty to the Company and QFs when deadlines or price changes are approaching, but more importantly to satisfy PURPA's "ratepayer indifference" mandate.[14]

Q. Why is it important to establish criteria for when a LEO arises?

A. FERC has established that PURPA allows a QF to sell to a utility under two commercial scenarios: (1) under a contract (PPA); or (2) through a non-contractual, but binding, legally enforceable obligation.[15] The LEO is important in a couple of contexts. First, it acts to prevent the utility from avoiding purchases from a QF by refusing to sign a power purchase agreement with the QF.[16] Second, it acts as a threshold standard a QF must meet in order to qualify to sell to a utility (at a given avoided cost prices). Thus, the LEO acts to protect both the QF and the utility (and ultimately the utility customers that will bear the costs of avoided cost purchases from QFs).

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[13] June 1, 2015 is the requested effective date for the Schedule 37 avoided cost price update by the Company.
[14] FERC has likewise affirmed the need to ensure customer indifference to utility purchases of QF power, noting that, in enacting PURPA, "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives." *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269 at 62,080 (1995) *overruled on other grounds, Cal Pub. Util. Comm'n*, 133 FERC ¶ 61,059 (2010). *See also PSC of Oklahoma v. State ex. rel. Corp. Comm'n*, 115 P.3d 861, 870-71 (Okla. 2005) ("The incremental cost standard is intended to leave ratepayers economically indifferent to the source of a utility's energy by ensuring that the cost to the utility of purchasing power from a QF does not exceed the cost the utility would incur in the absence of the QF purchase").
[15] *Grouse Creek*, at P 36.
[16] Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12214, 12224, FERC Order No. 69 (February 25, 1980).

Q. How do state and federal law differ on QF entitlement to avoided cost Pricing?

A. The issue of when a LEO arises should be determined by the states. "It is up to the States, not [FERC], to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law."[17] The states' discretion to determine when a LEO exists, however, is limited by FERC's PURPA regulations. Although it has failed to provide specific guidance, FERC has recently weighed in on the LEO issue. FERC's recent decisions provide general guidance that although states retain wide discretion to decide when a LEO arises under state law, a state may not require an executed contract as a "bright line rule" or precondition to a LEO.[18]

Q. Please describe the Oregon Commission's and FERC's current LEO rules.

A. The Oregon Commission's LEO rule is found at OAR 860-029-0010(29)(a)-(b), which provides that a LEO exists on the earlier of:

> (a) The date on which a binding, written obligation is entered into between a qualifying facility and a public utility to deliver energy, capacity, or energy and capacity; or
>
> (b) The date agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate.

Existing Oregon Commission rules, in combination with PacifiCorp's Commission-approved Oregon Schedule 37, state that a QF is not entitled to a particular avoided cost rate until both parties have executed a PPA or until the parties agree in writing to the date a LEO occurs.[19]

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[17] *Power Res. Grp. v. Public Util. Comm'n. of Texas*, 422 F.3d 231, 238 (5th Cir. 2005); *West Penn Power Co.*, 71 FERC ¶61,153, 61,495 (1995) (same).

[18] *See Grouse Creek*, 142 FERC ¶61,187, at P 36.

[19] *See* OAR 860-029-0100; *International Paper Co. v. PacifiCorp, dba Pacific Power*, 2009 Ore. PUC LEXIS 374 (2009).

While this rule reflects prevailing law within the state of Oregon, a series of recent FERC decisions have concluded that the Idaho Public Utility Commission (Idaho PUC) may not require a QF to obtain a fully executed agreement as a precondition to the QF's locking in a particular avoided cost rate. FERC ruled that if a QF "unequivocally commits" itself to sell to an electric utility, it may obtain a non-contractual, but binding, LEO that entitles the QF to the prevailing avoided cost prices.[20]

The United States Supreme Court has held that FERC's regulations in 18 C.F.R. part 292, which govern the purchase of electricity from qualifying small power production facilities, "afford state regulatory authorities…latitude in determining the manner in which the regulations are to be implemented."[21] Consistent with this discretion, FERC has historically stated it will defer to the states regarding the date on which a LEO is incurred.[22] But FERC has issued four orders in recent years that imposed an outer limit on state discretion. Although states have discretion to define when a LEO arises, FERC has stated its regulations preclude states from requiring an executed contract as a condition.[23]

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[20] *Grouse Creek*, 142 FERC ¶ 61,187 at P 36. (*citing Cedar Creek Wind LLC*, 137 FERC ¶61,006 (October 4, 2011); *Rainbow Ranch Wind, LLC*, 139 FERC ¶61,077 (April 30, 2012); *Murphy Flat Power, LLC*, 141 FERC ¶61,145 (November 20, 2012).

[21] *Federal Energy Regulatory Comm'n v. Mississippi*, 456 U.S. 742, 751 (1982). *See also* Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12214, 12230-31 (Feb. 25, 1980) (state regulatory commissions have "great latitude in determining the manner of implementation of the Commission's rules, provided that the manner chosen in reasonably designed to implement the requirements" of FERC's regulations).

[22] *See, e.g., Metropolitan Edison Co.*, 72 FERC ¶ 61,015, 61,050 (1995) ("It is up to the States, not [FERC], to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law."); *West Penn Power Co*., 71 FERC ¶ 61,153 (1995).

[23] *Grouse Creek; Murphy Flat*, 141 FERC ¶ 61,145 (2012); *Rainbow Ranch*, 139 FERC ¶ 61,077 (2012); *Cedar Creek*, 137 FERC ¶61,006 (2011).

Current Oregon law requiring a PPA executed by both parties before a QF is entitled to avoided cost pricing conflicts with these decisions. Three of the four orders addressed factual scenarios in which a QF signed a PPA before an avoided cost change,[24] but the utility had not yet signed the agreement. FERC criticized the Idaho PUC for requiring these QFs to obtain fully executed PPAs before they could lock in avoided cost rates, finding that the Idaho PUC's position was inconsistent with PURPA. The fourth and most recent order, *Grouse Creek*, indicates that a LEO may arise even before *any* party signs a PPA.[25] In each case, FERC ruled that the Idaho PUC may not require an executed contract in order to find a LEO.

While FERC's recent decisions explain that states do not comply with PURPA if they require an executed contract in order to form a LEO, the Fifth Circuit's September 8, 2014, decision in *Exelon Wind I, LLC v. Nelson*, affirms the wide discretion afforded the states in defining when a LEO arises under state law. In *Exelon Wind*, the Fifth Circuit held that PURPA gives states discretion to "define the parameters of the circumstances in which [QFs] could form Legally Enforceable Obligations."[26] The Court then held that a Texas PUC rule that limited LEOs to firm power sales was within the agency's permissible discretion because neither PURPA nor FERC's rules specifically addressed the question.[27] In reaching its decision, the

[24] In this line of cases, the critical deadline at issue was not a change to avoided cost, but a change in the size threshold for a QF's eligibility for the utility's published avoided cost rate. The Idaho PUC changed the eligibility threshold from 10 aMW to 100 kW, prompting QFs over 100 kW to seek agreements before the change went into effect.
[25] *Grouse Creek* at P 38.
[26] *Exelon Wind I, LLC v. Nelson*, 766 F.3d 380, 396 (5th Cir. 2014)] ("state regulatory agencies—rather than FERC—were empowered to define the parameters of the circumstances in which Qualified Facilities could form Legally Enforceable Obligations …. It is this essential holding which binds us here: under the cooperative federalism scheme created by PURPA, it is the PUC, rather than FERC, that defines the parameters for when a Qualified Facility may form a Legally Enforceable Obligation.")
[27] *Id.*

Fifth Circuit refused to defer to a FERC advisory letter that interpreted FERC's PURPA regulations as allowing all QFs, including those that produced non-firm power, to form LEOs.[28]

Thus, in Oregon, the Commission retains wide discretion to define when a LEO arises, so long as it does not require an executed contract.

Q. What are the implications in Oregon?

A. First, although Congress sought to promote energy generation by QFs through PURPA, it did not intend to do so at the expense of the consumer. PURPA requires utilities to purchase power generated by QFs, but also mandates that the rates utilities pay for such power "shall be just and reasonable to the electric consumers of the electric utility and in the public interest."[29] Oregon's PURPA regulations contain a parallel provision.[30]

Second, unlike Grouse Creek, the Oregon QFs with projects in the queue have had ample notice that the Company's avoided cost rates will be changing. The timing of PacifiCorp's avoided cost filings are mandated by statute—PacifiCorp is required to update its avoided cost prices at least every two years.[31] And with the docket UM 1610 Phase I Order No. 14-058, allowing certain avoided cost updates on May 1 of each year, again, the QFs have ample time and notice. The Oregon QFs arguably have sufficient notice that PacifiCorp will update its avoided cost pricing, and therefore these QFs have the opportunity to seek PPAs in a timely manner. Put another way, there are no surprises around the timing of avoided cost pricing that

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[28] *Id.* at 392.
[29] 16 U.S.C. §824a-3(b)(1).
[30] OAR 860-029-0040(1)(a) ("Rates for purchases by public utilities shall [be] just and reasonable to the public utility's customers and in the public interest….")
[31] ORS 758.525.

justify the disorderly and creative efforts some developers have taken to secure extant avoided cost pricing.

For example, consider the avoided cost update filed by the Company in April 2014. The Company's avoided cost update was mandated by an Oregon Commission order. On February 24, 2014, the Oregon Commission issued an order in Phase I of docket UM 1610 that resolved certain issues relating to avoided cost pricing and contracts.[32] The order required the Company, Portland General Electric, and Idaho Power to file updated PPAs and avoided cost rates consistent with the order within 60 days. This order should have put most (if not all) of the Oregon QFs on notice that the Company's avoided cost rates were changing. Moreover, PacifiCorp made its updated avoided cost filing on April 10, 2014, but the new pricing did not go into effect until August 20, 2014, over four months later.[33] Finally, PacifiCorp's Oregon Schedule 37 gives QFs a reasonably clear indication of how far in advance a QF would need to seek a PPA in order to get a contract completed by a certain date.

During that period the Company had 20 Schedule 37 QF PPA requests with the majority of the QFs (15) in the Oregon queue requested PPAs *after* PacifiCorp's April 10, 2014 avoided cost update and five PPAs submitted within three business days following the April 10, 2014, filing. Four PPAs were submitted on March 28, 2014, in anticipation of the statutory deadline. In fact, in its August 19, 2014 order, the Commission approved Staff's recommendation that Solexus and Cypress Creek

[32] Order No. 14-058 (Feb. 24, 2014).
[33] Oregon Commission Staff noted in its memorandum prepared for the Oregon Commission's August 19, 2014 public meeting that an August 20, 2014 effective date was appropriate because QFs had been given sufficient advance notice of the pricing change, and that additional time to allow for PPA negotiations was unwarranted.

(developer and owner of the Norwest Energy projects), had sufficient notice of the upcoming price change.[34]

Both Solexus and Cypress Creek sent emails to Staff stating that their projects were simply awaiting a final PPA or PacifiCorp's signature and asked that "the effective date of Pacific's filing be delayed so that they can be assured of receiving the current avoided cost purchase price." The Commission, however, found "The original filing was made on April 10, 2014, *which provided sufficient notice to the QFs* that avoided cost price changes were being considered."[35] At all times during the negotiations, the rule provided clear guidance on when a LEO occurs: "when a binding, written agreement is entered into" or the date the parties agree in writing as the date the obligation is incurred. OAR 860-029-0010(29).

Q. What establishes QF commitment?

A. One issue that has not been discussed in detail by FERC is what a QF must do in order to "unequivocally commit" to selling energy and capacity to a utility – a critical step in creating a LEO. The issue has not been fully fleshed out at FERC and remains an open question at the Commission. As noted previously, FERC's general policy is to defer to the states on the question of when a LEO arises.[36] Its recent orders make clear that state discretion is limited by the bounds of PURPA, but state regulatory bodies nevertheless retain wide discretion to establish requirements within those boundaries. Other states, for example, have required QFs to make specific showings before they can be viewed as "unequivocally committed" to selling to the utility, such as a date certain for delivery of energy and capacity, guarantees that a QF will protect

[34] Order No. 14-295, docket UM 1610 (Aug. 19, 2014).
[35] *Id* (emphasis added).
[36] *See West Penn Power Co.*, 71 FERC ¶ 61,153.

utility customers from harm if the project fails, evidence of permits, site acquisition, QF certification, and/or evidence that the QF is pursuing interconnection in a reasonable manner consistent with its commercial delivery date.[37] Texas, in fact, has a "90-day rule" that provides that a utility may be compelled to purchase power from a QF pursuant to a LEO only if the QF can deliver that power within 90 days.[38]

Although Oregon is still in the process of determining when it believes a LEO has arisen, PacifiCorp suggests the Schedule 37 and Schedule 38 processes that have already been approved by the Commission provides the best framework for defining specific requirements.

For example, PacifiCorp's Oregon Schedule 37 procedures require a QF to provide specific details about its facility, information about interconnection, evidence of QF certification, proof of facility ownership, a motive force plan, and other specific information. PacifiCorp believes the timeframes in Schedule 37, which assure some level of back-and-forth negotiations, are also essential to demonstrate "commitment" under the Oregon Commission-approved PPA process.

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[37] *See, e.g.*, Tex PUC Subst. R. 25.242(f)(1)(B) (QF must be within 90 days of power delivery to establish a LEO);; *Public Serv. Co.*,, 115 P.3d at 873 (Okla. 2005) (finding a LEO was created where QF made significant progress in the development of its project, including attempting to obtain environmental and other necessary permits, securing contracts for natural gas, transportation, construction, and operations and maintenance, including site studies, plant design, and negotiations with vendors for these services). *See also In Appeal of Pub. Serv. Co. of N.H.*, 539 A.2d 275, 295 (N.H. 1988) (requiring QF to demonstrate there is a reasonable expectation that the project will be on-line by the date specified and to demonstrate the economic viability of its project over its life before a LEO is created); *South River Power Partners, L.P. v. Pennsylvania Pub. Util. Comm'n*, 696 A.2d 926, 931 (Pa. Commw. Ct. 1997) (requiring QF to demonstrate it has the ability to carry out its responsibilities, including substantial action "to acquire the necessary permits, site development approval, construction plans, and financing" before a LEO is created).

[38] *See* Tex PUC Subst. R. 25.242(f)(1)(B); *Power Resource Grp., Inc., v. Public Util. Comm'n of Tex.*, 422 F.3d 231 (5th Cir. 2005) (upholding 90-day rule as consistent with PURPA).

Q. What criteria would you recommend the Commission adopt in connection with establishing a LEO?

A. In light of FERC's recent LEO orders, and in the absence of clear Oregon Commission guidance, PacifiCorp suggests the following are likely to be key criteria for determining whether a LEO has been created:

- The QF has engaged in an extended course of discussions with PacifiCorp, demonstrating a level of commitment to sell its power;
- The QF has agreed to all terms and conditions of the Oregon form PPA, and has made elections where required by the form PPA, allowing for agreement on the key terms and conditions of the agreement; and
- The QF has provided all material documentation and information required by the Oregon form PPA, with the exception of material that may be deemed ministerial.

The Company recommends that the Commission utilize, at least as pertaining to the Company, Schedule 37 (or Schedule 38 for non-standard QFs) to set criteria for establishing a LEO. Schedule 37 contains a step-by-step process for negotiating a power purchase agreement, including deadlines by which the utility must respond to various inquiries and submission from the QF. The Company believes that it is reasonable to establish that a LEO has arisen (in other words a QF has committed itself) when the QF approves the final draft power purchase agreement as contemplated in B(5) on page 10 of Schedule 37.

Some may argue that if such a standard were adopted the utility could frustrate the establishment of a LEO by dragging out negotiations or always demanding more information from the QF. This is simply not the case. Schedule 37 contains specific information the Company requires and timelines in which the Company must act. If the Company tries to request information beyond Schedule 37 or fails to act within the timeframes established in tariff the QF can seek relief from the Commission. Specifying the establishment of a LEO within Schedule 37 will allow both the utility and the QF to know the rules of establishing a LEO from the beginning and will create standards that the Commission can review and enforce if either the utility or the QF attempt to frustrate or manipulate the establishment of a LEO. In a similar vein, the standards and procedures in Schedule 38 could be used to establish when a LEO arises for non-standard qualifying facilities.

Failure to adopt criteria that require some affirmative action on the part of the QF places the utility in the position of potentially being required to accept and pay for energy from a QF that the utility has little or no information about. This can present commercial, safety and resource planning issues for the utility. Equally important, the lack of clear guidelines would allow QF developers to obtain pricing based on outdated information, to the detriment of Oregon customers and in violation of the ratepayer indifference mandate of PURPA.

It is hard to imagine the Commission, in other circumstances, finding a contract prudent when the utility entered into that contract without conducting reasonable due diligence. By adopting the criteria already contained in Schedule 37 and Schedule 38 the Company is able to ensure it has information to conduct the minimum due diligence necessary prior to entering into a commercial relationship with a QF and yet does not allow the Company to avoid a power purchase agreement by refusing to execute such an agreement. The Company also acknowledges that there may be individual circumstances that do not squarely fit into the Schedule 37 or Schedule 38 criteria (though the majority will), thus the Commission should always retain the ability to look at the individual facts and circumstances of any QF's claim for a LEO.

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. Please summarize the Commission's Order No. 14-058 in docket UM 1610 Phase I regarding third party transmission cost?

A. The Commission acknowledged that third party transmission cost as a result of a purchase by the utility to move a QF's output from a load pocket where the QF's generation exceeds the load to another load area on the utilities system is the responsibility of the QF. Specifically, the Commission stated:

> 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.[39]

Q. Should the costs or benefits associated with third-party transmission service be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?

A. Any costs and benefits of third-party transmission service should be attributed to the

[39] Docket UM 1610 Phase I, Order No. 14-058, February 24, 2014, Page 22.

individual QF and should be reflected as an adjustment to the avoided cost price or as a contractual adjustment to billing in the PPA. The costs and benefits of third-party transmission should not be incorporated into the actual calculation of the standard avoided cost; rather the costs and benefits should be captured on an individual QF project basis in the PPA between the QF and Company as an addendum to the agreement. This is necessary because each project will be unique based on geographical location and the local electrical system loads and resources. Including costs or benefits associated with third party transmission would create unwarranted subsidization within QF prices depending on the location of the QF or local transmission loads.

Q. Under what circumstances would third-party transmission be required for a QF contract?

A. The Company's Oregon service territory is not continuous. Rather, it is composed of multiple non-adjacent allocated service territories across the state—some large, some small—all interconnected by transmission lines. In some instances, the Company's transmission function (PacifiCorp Transmission) controls the transmission system interconnecting elements of the Company's larger service territory. In other cases, the Company purchases service across transmission owned by a third party in order to deliver (or export) generation to (or from) an isolated portion of its service territory. Many of these agreements are legacy transmission agreements developed for the one-way delivery of power into a load and not for exporting power out of the area where generation may exceed load. The Company refers to these areas that are entirely or partially reliant on third-party transmission as "load pockets."

Excess generation in a load pocket is primarily expected to occur in the off-peak time period or during seasonal periods when customer loads are normally lower and cannot absorb the generation, but also may occur with the addition of one or more QF projects within a load pocket. Under minimum load conditions, the Company must either back down its own resources, if it has any in the load pocket, move the generation elsewhere (if feasible), or curtail the generator[40] as a last resort because of lack of transmission capacity.

While the Company recognizes that locational transmission constraints and the need for transmission upgrades should not prevent project development, any incremental cost resulting from the constraint or upgrade should be borne by the developer that elected to site its project in a load pocket, and not by customers.

Analysis of transmission system constraints and the cost of options for dealing with those constraints should be incorporated into the QF pricing and contract process so that appropriate adjustments can be made, either for the incremental cost borne by the utility or the benefits to the utility associated with localized generation. In many cases, the analysis of the transmission system will take additional time to complete, involves the QF, PacifiCorp's transmission function for interconnection, PacifiCorp merchant and the third party transmission provider for transmission service, and needs to be accounted for when establishing the contract process schedule.[41]

Q. Please describe the nature of the issue.

A. The Company's load and resource balance within an Oregon load pocket reflect a mix

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[40] PacifiCorp recognizes its PURPA obligation to purchase and points out the curtailment option as the last resort when the third-party transmission provider has no available transmission capacity to purchase.

[41] Interconnection and transmission service are two separate processes. Interconnection is between the QF and the transmission provider while transmission service is between PacifiCorp merchant and the transmission provider.

of conditions ranging from those with surplus internal generation to those with inadequate internal generation. Moreover, some load pockets exhibit seasonal variations between surplus and inadequate internal generation, relative to their loads. When new generation is interconnected to a load pocket and creates a surplus of local resources, then the Company must purchase transmission out of the load pocket if available or else curtail the local generation, to the extent the new generation exceeds local load and there is no available transmission to purchase. Thus, any time a new generator causes generation within a load pocket to exceed load, the Company will incur an additional cost to transmit the excess load pocket generation across third-party transmission to another load pocket that has sufficient load to accommodate the generation.

The Company therefore can alleviate a load pocket surplus generation condition caused by proposed QFs if it can purchase firm point-to-point transmission from the third-party transmission provider under the provider's Open Access Transmission Tariff (OATT). An example is Bonneville Power Administration (BPA). Firm point-to-point (PTP) transmission may be purchased on a short-term or long-term basis where short-term is for a month, a day, or even an hour, and long-term is for a minimum one year, but a minimum five-year commitment is required to obtain renewal rights for continuing service beyond the initial commitment. Long-term firm (LTF) PTP is the only form of transmission service that provides a dependable right to wheel surplus generation from a load pocket to the Company's larger system for the full term of a PPA. Short-term non-firm transmission may also be available but is not used for network load service because it is subject to displacement by other parties who have firm transmission or higher priority non-firm transmission.

In the event another transmission customer owns or purchases firm or higher priority non-firm transmission from the transmission provider across the same path, the third-party transmission provider will deny the lower priority non-firm transmission use if there is not enough capacity for all customer uses. Therefore, in order to ensure that firm third-party transmission service will remain available over the term of the PPA, the Company purchases long-term firm PTP transmission, if it is available. In all cases in a load pocket where a QF's delivery exceeds load and the Company must rely on third-party transmission to wheel excess generation out of the load pocket, the Company expects to incur additional costs to secure such transmission services from the third-party transmission provider.

Q. Has the Company incurred third-party transmission costs with any of its current standard contracts under Schedule 37?

A. Yes. The Company's recent experience with the Threemile Canyon Wind Farm 1, LLC (Threemile) 9.9 MW wind QF project is a good example and illustrates the incremental costs that are involved. In eastern Oregon, BPA owns transmission linking the Company's load pockets to other portions of PacifiCorp's system. Dalreed is a PacifiCorp load pocket near Arlington, Oregon where loads range from about 44 MW peak during the summer to less than 2 MW during the winter.

Before the Threemile project become operational in 2009, there was no generation in the Dalreed load pocket and the Company had no need to secure transmission service to export energy out of the Dalreed load pocket. The Company's legacy transmission service agreement with BPA reflected that as a one-way agreement to deliver power *into* the Dalreed load pocket and not *out of* the load pocket. Therefore, when generation was constructed that exceeded load in the load pocket, there was no existing transmission service for wheeling power out.

In order to insure that any excess generation could be moved to load outside the Dalreed load pocket, the Company initiated a purchase request of long-term firm PTP transmission (with rollover rights) from BPA and entered BPA's queue in the spring of 2009 to secure such transmission prior to initial start-up of the wind turbines. BPA determined it would not have firm long-term capacity available to grant this request until upgrades were completed on their system.

In 2009, Threemile began commercial operation, and excess generation occurred throughout the winter months. As an interim measure, the Company purchased short-term firm PTP transmission on a day-ahead and month ahead basis during the winter and spring months to address the period when generation could exceed load. This was a more administratively burdensome approach for the Company but was effective while waiting for BPA's determination on LTF PTP.

This continued until early January 2014 when BPA issued 8.0 MW of conditional LTF PTP transmission service. Conditional firm transmission service is a defined type of LTF transmission service in BPA's OATT for which BPA specifies a number of hours per year or system condition in which BPA can curtail the conditional LTF reservation prior to curtailing other LTF service. It is an acceptable form of LTF PTP used by the Company to move generation to load, recognizing the possibility of a directed curtailment[42] by the transmission service provider, BPA. When LTF PTP transmission is ultimately available at Dalreed from BPA, BPA would transfer the conditional LTF to strictly their long-term firm point-to-point to ensure firm rights in all hours for any excess generation.

In theory, the cost to export excess generation from Dalreed should be partially offset by any transmission service savings realized under the current transmission agreement with BPA. Therefore, if the QF generation reduced peak imports, the Company might realize a reduction in transmission service charges into the load pocket.

In actuality, the amount of savings realized has been minimal. In 2009, there was no reduction in peak hourly demand and in 2010 Threemile reduced the annual peak hour demand at Dalreed by just over 300 kW. Compared to the cost the Company incurred for short-term firm transmission out of Dalreed, or the estimated annual cost the Company expects to incur once long-term firm transmission out of Dalreed is available, the reduction to import costs is negligible. Adding the Threemile facility to the Dalreed load pocket has had a net effect of increasing the Company's cost above the Schedule 37 standard avoided cost rates.

Q. Is the Threemile Canyon Wind Farm 1, LLC example an isolated case?

A. No, while Threemile Canyon Wind Farm has the most detail, there are other QF projects in Oregon that have executed PPAs with the Company that are located within a load pocket including TMF Biofuels, Adams Solar and Elbe Solar.

[42] Per BPA's OATT, conditional curtailments are conducted based on the NERC priority levels specified in the e-Tag that accompanies the scheduled delivery.

Q. How has the Company dealt with these additional QFs in load pockets?

A. In the same manner as the Threemile Canyon Wind Farm I, LLC situation. The Company assessed the minimum load in the pocket through review of the generation interconnection system impact study available on OASIS, joint discussions with the QF and PacifiCorp Transmission, and review of the transmission service agreements with the transmission provider (i.e., BPA, PGE, etc.). Once the minimum load is identified and compared to the QF generation profile, the Company has a basis to request LTF PTP transmission service from the transmission provider out of the load pocket. The Company then provides an estimate of the monthly cost of transmission service to the QF based on the amount and the transmission service provider's OATT.

Q. Are minimum load issues unique to QF resources?

A. No. However in the case of purchases from non-QF resources, minimum load issues are handled through contract price adjustment and/or curtailment of the resource.

Q. Are the costs or benefits associated with third-party transmission incorporated into non-standard avoided cost prices?

A. Yes. In the same manner as how Schedule 37 projects are evaluated if there is a load pocket, the calculation of the project specific avoided cost prices for a non-standard QF, the costs or benefits associated with third-party transmission, if any, are calculated. The costs and benefits are included in the contract between the QF and the Company as an addendum to the PPA for any avoided cost price adjustment and/or curtailment of the resource.

Q. Does this conclude your direct testimony?

A. Yes.