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May 22, 2015

VIA E-MAIL ONLY

Attention: Filing Center
Public Utility Commission of Oregon
3930 Fairview Industrial Drive SE
P.O. Box 1088
Salem OR 97308-1088

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

To the Filing Center:

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

1. May 22, 2015 Testimony of Diane Broad, Exhibit ODOE/800, with accompanying Exhibit ODOE/801; and

2. May 22, 2015 Testimony of Philip Carver, Exhibit ODOE/700, with accompanying Exhibit ODOE/701.

Sincerely,

Renée Marleau for

Renee M. France
Senior Assistant Attorney General
Natural Resources Section

Enclosures
RMF:jrs/#6518003

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DOCKET NO. UM 1610
Phase 2
EXHIBIT: ODOE/800
WITNESS: DIANE BROAD

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Testimony of Diane Broad

May 22, 2015

Q. PLEASE STATE YOUR NAME AND ORGANIZATION.

A. My name is Diane Broad. I am a Senior Policy Analyst for the Planning and Innovation Division within the Oregon Department of Energy (ODOE). The business address is 625 Marion St. NE, Salem, Oregon. I am testifying on behalf of ODOE.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. I am a policy analyst with particular expertise in electric utility transmission and distribution systems and operations, renewable generator interconnection standards and procedures, and integration of variable energy resources. I gained this expertise through eighteen years of practice as an electrical engineer in consulting, serving electric utilities and renewable project developers, and in one year as a policy analyst at ODOE. I am a registered Professional Engineer in the State of Oregon.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I will address issues number three, four and nine from the ALJ memo of March 26, 2015. The other ODOE witness, Phil Carver, addresses issues one, five and six from the same memo.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. On issue number three I will describe the flaw in the current method for adjusting capacity payments to variable Qualifying Facilities (QFs) for both the standard renewable and non-renewable avoided costs.

On issue number four I will describe ODOE's proposed process for calculating adjustments to capacity payments to eliminate the double discounting error under the current method.

On issue number nine I will describe ODOE's proposed alternatives for calculating third-party transmission costs to be included in the standard contract for the purpose of moving QF output out of a load pocket.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit ODOE/801, Broad/1, a spreadsheet showing proposed calculations for capacity payments to variable QFs under the standard non-renewable avoided costs.

ISSUE NUMBER THREE, PART ONE

Q. 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?

A. Yes. The methodology approved in Order No. 14-058 is flawed and needs to be corrected.

Q. DESCRIBE THE METHODOLOGY ESTABLISHED IN ORDER NO. 14-058 FOR ADJUSTING THE AVOIDED COST RATES PAID TO QFs BASED ON THE RELATIVE CAPACITY CONTRIBUTIONS OF THE QF RESOURCE AND THE AVOIDED RESOURCE ("THE CURRENT METHOD").

A. Under the current method, the avoided cost rates paid to a QF are adjusted by multiplying the capacity portion of the on-peak per-MWh avoided cost rate by 1) for standard non-renewable avoided costs, the capacity contribution of the QF resource type, or 2) for standard renewable avoided costs, the incremental capacity contribution of the QF resource type relative to the avoided renewable resource.

Q. DID ODOE SUPPORT ADOPTION OF THE CURRENT METHOD IN PHASE 1 OF UM 1610?

A. Yes, ODOE supported, and still supports, the concept that avoided costs prices paid to a QF should reflect the capacity contribution of the QF resource type relative to that of the avoided resource in order to more accurately reflect actual avoided costs. However, it became clear after the utilities filed their updated avoided costs in compliance with Order No. 14-058 that the current method significantly undercompensates variable QFs for their capacity contribution.

For example, under the new renewable rates, the current method was intended to compensate a solar QF for its incremental capacity contribution over that of the avoided wind resource. Using the numbers in the example provided in Staff/400, Andrus/5, that incremental capacity contribution is 9.4 percent. Therefore, a one MW solar QF should receive capacity payments totaling 9.4 percent of the fixed cost of one MW of the proxy single-cycle combustion turbine (SCCT) capacity resource. Instead, under the current method, a solar QF receives less than 3 percent of the fixed cost of the proxy capacity resource. This means that, under the current method, a solar QF is only receiving 30 percent of the capacity value that it actually contributes to the utility's system.[1]

This result is contrary to the Commission's intent to produce more accurate avoided cost estimates. Therefore, ODOE urges the Commission to revise the current method to correct this flaw.

Q. DESCRIBE THE FLAW IN THE CURRENT METHOD.

A. The flaw is clearly explained in Staff's opening testimony on this subject (see Staff/400, Andrus/4-5). I will provide additional explanation here.

The utility's capacity costs are represented by the fixed costs of an SCCT, and are measured in annual dollars per kW of capacity. When receiving power from a QF, the utility avoids those capacity costs in proportion to the QF resource type's incremental capacity contribution. A generating resource's capacity contribution represents the percentage of its nameplate capacity that reliably contributes to the utility's capacity needs.

In developing the current method, Staff intended to determine the appropriate avoided capacity cost to include in the on-peak price by multiplying the capacity contribution of the QF resource "by the dollar value of capacity."[2]

Staff's error was in using the volumetric (per-MWh) capacity price to

[1] Using the numbers in Staff/401, Andrus/1, the solar QF's incremental capacity contribution of 9.4 percent equals an annual capacity value of $13,190. Under the current method the solar QF receives annual capacity payments of just $3,951, or 30% of its actual capacity contribution.
[2] Staff/103, Bless/4.

represent the "dollar value of capacity" rather than the annual dollars-per-kW fixed cost of the proxy avoided SCCT capacity resource.

It is inappropriate to use the volumetric capacity price amount to represent the "dollar value of capacity" because the utility does not incur capacity cost on a per-MWh basis during the resource deficiency period. The utility incurs capacity cost on a per-kW basis. Therefore, the capacity cost that is avoided by purchasing from a QF is the annual per-kW cost that the utility would incur but for the QF. The dollar value of the avoided capacity cost is directly proportional to the QF resource type's incremental capacity contribution.

The correct way to determine the capacity cost avoided by the QF is to multiply the QF resource type's incremental capacity contribution by the utility's annual per-kW capacity cost. Once the avoided capacity cost is determined, the on-peak per-MWh capacity price must be established based on the QF resource type's generating characteristics such that the QF receives the full dollar value of its avoided capacity cost, assuming the QF generates as much energy during on-peak hours as expected for that resource type.

As Staff explains, the current method does not do this. Instead, the current method "reduces the volumetric capacity price by a fraction representing the QF's relative contribution to capacity. However, because the volumetric price is specifically designed to spread the cost of capacity over a number of MWh as if the QF's on-peak capacity factor is equivalent to that of a combined-cycle combustion turbine (CCCT), it is impossible for an intermittent resource that cannot operate in all those hours to receive all of the capacity dollars to which it is entitled."[3]

Q. WHY WAS THE METHOD CHANGED IN ORDER NO. 14-085?

A. Under the previous method, prior to Order No. 14-085, variable QFs received the same per-MWh capacity rate as baseload QFs. There was no explicit adjustment for capacity contribution. However, because a variable resource does not generate at full capacity during all on-peak hours, a variable resource QF earned less in cumulative capacity payments than a baseload QF. Prior to Order No. 14-058, the QF was compensated for capacity in proportion to the QF resource type's on-peak capacity factor, or the average percentage of nameplate capacity generated during all on-peak hours. A solar QF with an on-peak capacity factor of 27.5 percent would have received annual capacity payments totaling 27.5 percent of those received by a baseload QF operating with the same capacity factor as the avoided CCCT. Capacity *factor* will not always produce an accurate estimate of a utility's avoided capacity cost because it is a characteristic of the QF resource independent of the utility system to which it is delivering energy. A more accurate estimate of a utility's actual avoided capacity cost is its capacity *contribution*, which depends on both the characteristics of the QF resource and the characteristics of the utility system to which it is delivering energy. If a resource's on-peak capacity factor and its capacity contribution are the same value, the previous method would have accurately compensated for

[3] Staff/400, Andrus/4.

avoided capacity costs. But if a resource's on-peak capacity factor is higher than its capacity contribution value, as is the case for wind in all three utility service territories, the previous method overcompensated that resource for capacity. For example, in Portland General Electric's 2013 Integrated Resource Plan, there is a large discrepancy between wind's on-peak capacity factor (54 percent) and wind's capacity contribution (5 percent).[4] In order to produce more accurate avoided cost estimates, the Commission ordered that the method for calculating capacity payments to different QF resource types be modified to account for the capacity contribution of those resource types.

Q. WHAT IS THE RESULT OF THE FLAW IN THE CURRENT METHOD?

A. The result of the flaw in the current method is that the capacity payments to a variable QF are now doubly discounted and the QF is severely undercompensated for avoided capacity. As explained earlier, prior to Order No. 14-058 the QF was compensated for avoided capacity proportional to the QF resource's on-peak capacity factor. That is the first discount and it still applies under the current method. The second discount, in which the capacity payment is multiplied by the QF resource type's capacity contribution percentage, further reduces the value of the capacity payment to well below actual avoided cost.

The on-peak capacity factor and the capacity contribution are two different ways to estimate the portion of capacity resource costs that are avoided by a QF resource. Combining the two, as the current method does, creates

[4] PGE 2013 IRP at 174.

inappropriate double discounting.[5] To eliminate the double discounting and to accurately reflect actual avoided costs, the capacity payments must recalculated (not just further reduced) based on the capacity contribution of the QF resource type.

ISSUE NUMBER THREE, PART TWO

Q. HOW SHOULD THE METHODOLOGY BE REVISED?

A. The Commission should adopt staff's proposed method Option 1, as outlined in Staff/401, Andrus/1. Staff's revised method includes two steps. First, determine the incremental avoided capacity cost in annual dollars-per-kW that is attributable to the solar QF relative to the avoided wind resource. This is done by multiplying the incremental capacity contribution of a solar resource compared to that of the avoided wind resource by the utility's annual cost-per-kW of an SCCT capacity resource. Second, convert that incremental solar capacity contribution value from an annual dollars-per-kW amount into a per-MWh payment rate based on the expected annual generation of the solar resource. This is necessary so that the solar QF will be compensated for its incremental avoided capacity costs each year, subject to the QF delivering as much on-peak energy as expected.

ISSUE NUMBER FOUR

Q. SHOULD THE CAPACITY CONTRIBUTION CALCULATION FOR THE STANDARD NON-RENEWABLE AVOIDED COST PRICES BE MODIFIED

[5] ODOE/700, Brockman/3.

TO MIRROR ANY CHANGE TO THE SOLAR CAPACITY CONTRIBUTION CALCULATION USED TO CALCULATE THE STANDARD RENEWABLE AVOIDED COST PRICE?

A. Yes. The double discounting error occurs in the capacity payment adjustments adopted in Order No. 14-058 for both the standard renewable and standard non-renewable avoided costs. The current method for adjusting capacity payments under the standard non-renewable avoided costs should be revised to incorporate the same two-step approach proposed by Staff for the standard renewable avoided costs.

First, determine the avoided capacity cost in annual dollars-per-kW that is attributable to the variable QF resource type. This is done by multiplying the capacity contribution of the variable resource type by the utility's annual cost-per-kW of an SCCT capacity resource. Second, convert that capacity contribution value from an annual dollars-per-kW amount into a per-MWh payment rate based on the expected annual generation of the variable resource type, such that the QF will be compensated for its avoided capacity costs each year, subject to the QF delivering as much on-peak energy as expected.

An example of this two-step process for adjusting the standard non-renewable avoided costs is provided in Exhibit ODOE/801, Broad/1.

Q. IS STAFF'S PROPOSED REVISED METHOD ALREADY IN USE BY ANY OF THE UTILITIES?

A. Yes. Idaho Power uses this same approach for negotiating QF rates, but uses the characteristics of the project-specific QF resource (e.g. for solar: location, panel tilt and orientation, components) instead of using assumed characteristics of a proxy QF resource type. Under Idaho Power's method, the "project-specific capacity contribution is multiplied by the annual capacity cost of the SCCT, and then spread over the project's forecasted annual energy deliveries to determine the avoided cost of capacity rate for that specific project."[6] This method calculates the fixed costs of the capacity resource that are avoided by the specific QF based on its capacity contribution, and establishes a payment rate based on the QF's expected energy deliveries. That way, the QF will receive the full value of the fraction of the SCCT capacity that is avoided by the QF, if the QF delivers energy as expected. By customizing the rate to each QF, this method accurately represents actual avoided capacity costs. For standard rates, it is reasonable to use the characteristics of a proxy QF resource type.

Q. IS IDAHO POWER'S CONCERN THAT STAFF'S RECOMMENDED REVISED METHOD WILL RESULT IN PAYMENTS HIGHER THAN AVOIDED COST[7] VALID?

A. No. Idaho Power has incorrectly equated the per-MWh capacity payment rate to avoided capacity cost. Avoided capacity cost is measured in annual dollars per kW. To determine if the QF is receiving more than avoided cost, one must

[6] Idaho Power/600, Youngblood/10.
[7] *See* Idaho Power Company's Post-Hearing Brief, at 5-6.

compare the *sum* of capacity payments received by the QF in a year to the annual dollars-per-kW capacity cost that is avoided by the QF's generation, not simply look at the per-MWh rate.

Idaho Power has correctly noted that, under Staff's revised method, a solar QF delivering power to Idaho Power will receive a higher per-MWh capacity payment rate than a baseload QF.[8] But that is not the same as receiving more than avoided cost. A solar QF will not receive more than avoided cost. Under Staff's revised method, the total annual capacity payments to a solar QF will always be less than the total capacity payments to a baseload QF even if the solar capacity payment *rate* is higher.

As long as the capacity value is calculated appropriately[9], Staff's proposed revised method will provide the most accurate estimate of capacity costs actually avoided by the QF because the per-MWh payment rate will be set such that the QF is compensated accurately for the capacity cost it causes the utility to avoid.

[8] Under Staff's revised method, the adjusted per-MWh capacity rate paid to a variable QF will be higher than the per-MWh capacity rate paid to a baseload QF *only* if the variable resource's capacity contribution is higher than its on-peak capacity factor. This is the case for a solar resource delivering power to Idaho Power. In most cases the opposite is true, so the adjusted per-MWh capacity rate paid to the variable resource QF resource will normally be less than the per-MWh capacity rate paid to a baseload QF.

[9] The appropriate method for calculating capacity value is currently being investigated in UM 1725.

ISSUE NUMBER NINE

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

A. Summary of ODOE position: Appropriate avoided cost allocation to QFs should be include a clear and consistent assignment of costs for transmission services necessary to move the QF output out of a load pocket where applicable. As part of the clarification, the term “load pocket” needs to be defined in this docket. QFs with lower capacity factors are more financially burdened by a transmission cost allocation which is flat across all months of the year. It is not always the case that the company executing a power purchase agreement (PPA) needs to secure transmission for every hour of the year, and in an amount equivalent to the maximum expected excess generation, in order to absorb all the output of the QF. The transmission need for each project should be based on the generation profile provided by the project in the standard contract. The transmission need for each project should be based on a realistic estimate of the number of low-load hours for the load pocket. If load grows more than expected over the 20 year contract or if QF and distributed generation grows more slowly in a load pocket, the standard contract could include a mechanism for update payments to the QF to reflect transmission costs that are lower than expected when the contract was signed.

Q. WHAT EFFECT DOES GENERATION BY A QF HAVE ON SYSTEM OPERATIONS IF THE QF IS LOCATED IN A LOAD POCKET?

A. Generation from a QF is absorbed by load on the electric grid, regardless of which company serves that load. However, there are geographically-isolated areas for which electric utilities have supplied the retail load using power generated by large central power stations and transmitted either by facilities owned by the utility or services purchased from a third-party transmission provider. QF output in such a geographically-isolated area, or load pocket, may exceed the minimum retail load served by the company. This is called "excess generation." In this case, the company needs to have the transmission capability to move excess generation *out of* the load pocket. The amount of the QF's generation which is excess generation varies based on the generation profile, which for variable energy resources fluctuates hour-to-hour as well as seasonally. The amount of excess generation also varies based on the timing and quantity of the minimum load in the load pocket. Dependent on the characteristics of the retail load, this minimum load situation may exist for a small fraction of the hours during a given year. Therefore, the standard contract should allow the QF to choose from among a limited set of different types of transmission service.

Q. DO WE CURRENTLY HAVE AN ADEQUATE DEFINITION OF A LOAD POCKET?

A. Load pocket is currently undefined. Tentatively, the Commission might define the utility's load pocket as a portion of its electric utility retail service territory that is not served by its owned transmission system from other portions of the utility's service territory and has limited transmission contracts to deliver net generation out of that portion of its territory.

Q. WHAT IS THE SCOPE OF THE TRANSMISSION COSTS CURRENTLY AGREED IN POWER PURCHASE AGREEMENTS FOR QFs IN LOAD POCKETS RELATIVE TO THE QF GENERATOR SIZE AND PAYMENT FOR THE GENERATION?

A. In response to data requests by CREA, PacifiCorp disclosed[10] that three QFs in load pockets have executed PPAs which include transmission costs paid by the QF. Two of the projects are in development, and one is currently operating.

The operating project, a TMF Biofuels 4.8 MW biogas facility, and PacifiCorp negotiated a $/MWh reduction in the contract price for a 10-year term. The PPA negotiation was finalized before the UM 1610 Phase 1 ruling on February 24, 2014, which assigns to the QF the cost of transmission service for excess generation out of the load pocket to load. The contract adjustment results in the project taking a reduction in generation payment of roughly 4 percent to 7 percent for on-peak generation and roughly 6 percent to 9 percent for off-peak generation over the contract term. The transmission

[10] Attachment CREA 9.1.

services procured are long-term firm (LTF), point-to-point (PTP) transmission for 5.0 MW which covers all hours of operation.

The two projects in development, Adams Solar Center and Elbe Solar Center, are each 10 MW solar facilities in a load pocket. Adams Solar Center and Elbe Solar Center have the same developer and owner. The PPAs for these projects were executed after the UM 1610 Phase 1 ruling regarding cost of transmission service out of load pockets. An addendum to the PPA describes the transmission services needed and how the costs will be assigned to the QF. Firm PTP transmission service for 10 MW will be procured from Bonneville Power Administration and from Portland General Electric for each project. The costs are fixed each month, regardless of the output of the project. The cost of transmission service results in each project taking a reduction in generation payment of roughly 14 percent in a summer month of nearly peak production (June) and a reduction of roughly 60 percent in a winter month of nearly lowest production (January). The annual cost of 10 MW of transmission service is expected to be $272,616 per year for each project.

Q. IS THERE A CONSISTENT APPROACH FOR PROCURING AND CALCULATING THE COST OF TRANSMISSION SERVICE?

A. No. In the examples given above for the 4.8 MW biogas facility and the 10 MW solar facilities, there does not appear to be a consistent approach. The Commission should weigh the cost burden to QFs and the potential cost impact to utilities when considering the two distinct approaches: allocating costs on a dollars per MWh of generation basis, versus a flat cost charged per month regardless of MWh of generation. There is value in allowing the QF to choose one approach or the other, while still compensating the utility for the real costs of securing the transmission service.

When calculating the cost of transmission service, it is important to choose the type of transmission service best suited to the need. In responses to data requests, PacifiCorp has shown a consistent preference for LTF PTP transmission as the mechanism for modifying the standard contract. In principle this is advantageous to the QF as well, since transmission service is provided for all hours of the year and there is no risk of curtailment. However, the responses from PacifiCorp also show that projects operating without LTF PTP transmission service, such as Three Mile Canyon Wind Farm with 9.9 MW output, were operated without curtailment *and* with transmission service of less than nameplate capacity. Three Mile Canyon Wind Farm was operated from its commercial operation date of September 1, 2009, until January 1, 2014, utilizing BPA short-term firm PTP transmission service in the amount of 8.0 MW. PacifiCorp chose a service level of 8.0 MW due to the historical minimum load of 2 MW in the load pocket.

In PacifiCorp's response to CREA Data Request 11.3 (c), the cost of the short-term firm PTP transmission service is shown to be in the range of $9,600 to $22,260 per month. Interestingly, over four years of operation no transmission services were required in the summer months (May through August). The resulting maximum yearly charge for moving 9.9 MW of QF load out of the load pocket using short-term firm PTP transmission was $110,720. PacifiCorp purchased 8.0 MW of conditional firm PTP transmission for the project since January 1, 2014. BPA was not able to offer PacifiCorp LTF PTP transmission, so the company purchased conditional firm PTP transmission. The cost is the same as LTF and since January 2014 has been $13,888 per month, equivalent to $166,656 per year.

For the solar projects referenced above, depending on the summer load in the load pocket, short-term firm PTP transmission could offer cost savings.

Q. GIVEN THAT THE ISSUE STATEMENT ASSUMES THAT ACCOUNTING FOR THIRD-PARTY TRANSMISSION RESULTS IN INCREASED COSTS TO QFs <u>IN THE STANDARD CONTRACT</u>, HOW CAN WE BE SURE TO INCLUDE THE LONG-TERM VIEW?

A. To calculate third-party transmission costs and account for them, the standard contract applies a fixed cost, comparable to an “integration cost,” to QFs over the entire 15-year or 20-year contract period. The transmission system operators in Oregon have continually sought technical and contractual optimizations to lower integration costs for renewable, variable energy resources. Requiring QFs to pay for LTF PTP transmission equivalent to the maximum nameplate generation of the project does not appear to take advantage of these optimizations.

Many important changes could occur in a utility’s resources and operations over the course of a QF standard contract, e.g. load growth in the load pocket, regional transmission upgrades, alternate contractual arrangements with transmission service providers, or the development of energy storage. Any or all of these changes would result in a reduction, and perhaps elimination, of the cost for third-party transmission services. PacifiCorp states in response to CREA Data Request 11.6 (c) and (d) that the company has redirected a portion of its existing firm PTP transmission rights on a non-firm and firm basis for the purpose of delivering QF output to a load out of a load pocket. The company redirected BPA LTF transmission to accommodate delivery of output of the Three Mile Canyon Wind project. The company took this action because the LTF transmission was not fully utilized.

The Commission should ensure that the transmission costs are calculated in a manner that accomplishes two goals:

1. The calculation must realistically reflect the need for transmission of excess generation over the whole year, considering the historical minimum load in the load pocket and the generation profile of the QF described in the standard contract.[11] A QF having variable generation and which is expected to have low generation during months of low loads in the area would be penalized by a flat-fee approach to transmission services. The QF should not be forced to pay for transmission at nameplate capacity of the facility for all hours of the year. The standard contract might give the option for the QF to

[11] "Seller's Motive Force Plan" in Exhibit D-1

purchase short-term firm PTP transmission if the owner of the QF believes it to be cost effective and have minimal risk of curtailment.

2. The calculation must account for the potential for transmission costs to change over the contract term. The electric utility could propose two options in the standard contract: a $/MWh adjustment to the avoided cost rates, or a $/kw-month transmission service fee. At the end of the year, whichever option is chosen, the utility should perform an analysis of the cost of transmission service by month and refund any overpayment to the QF.

Q. ALTHOUGH OVERALL UTILITY LOAD GROWTH IS MODEST IN THE REGION, HOW SHOULD WE ADDRESS THE ISSUE THAT SPECIFIC TYPES OF LOAD GROWTH CAN HAVE A LARGE EFFECT ON OPERATIONS IN A LOAD POCKET?

A. Certain rural areas in Oregon, especially in the eastern part of the state, are attractive locations for data centers due to one or more factors: a cool climate, inexpensive electricity, the availability of property tax incentives in economically-distressed rural enterprise zones, and the absence of a state sales tax. Data centers could change the whole outlook on load pockets, for three reasons:

a. The data center load is likely to be large in comparison to the existing load in the area. The introduction of a single large data center into a load pocket could eliminate the need for transmission of QF excess generation out of the load pocket, depending on the size of the QF relative to the data center.

b. The data center load shape is typically very flat. When the load for a typical data center is combined with the load for the existing users in the area, the resulting load shape will have less of a “trough” for low-load hours. The result is that QF generation would need to be exported on third-party transmission for fewer hours per year.

c. A trend in data center design is to include on-site renewable energy generation, usually from variable energy resources like solar. While the addition of a large, nearly constant load could help an existing QF generator in the area, if that load is offset or exceeded by output from on-site generation then the load pocket problem would be compounded. Will a data center which has been recruited to the state be willing to pay the same “integration costs” for its excess generation as QFs would be expected to pay in a standard contract with the utility?

Other load types added to a load pocket, a new prison for example, could have very similar effects on the electric system. If the QF is in a load pocket where a large new load is under development, the standard contract could include the option for exemption from transmission costs. The exemption could be over the entire contract term or be limited to an initial period, perhaps the first 5 years. Alternatively, there could be a finding each five years whether or not an area is still a load pocket. This finding would apply to all QF contracts in the area.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DOCKET NO. UM 1610
Phase 2
EXHIBIT: ODOE/801
WITNESS: DIANE BROAD

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Exhibit 801
Accompanying the Testimony of
Diane Broad

May 22, 2015

UM 1610
ODOE Proposal to Correct the Capacity Adjustment to the
Standard Avoided Cost Prices for Variable QFs
11/18/2014

The example below is for PacifiCorp's standard avoided cost prices. Inputs are indicated in yellow; other numbers are calculated.

ASSUMPTIONS:
- The avoided capacity resource is an SCCT. The SCCT inputs are based on PacifiCorp 2014 approved avoided cost filing, Advice No. 14-007, Appendix 1, Table 8.
- The number of on-peak hours is assumed to be 4,992 -- the number used in PacifiCorp's 2014 approved avoided cost filing.
- Solar and wind peak capacity contributions are from PacifiCorp's 2013 IRP, Appendix O.
- Solar annual capacity factor is from PVWatts, based on a premium-module south-facing fixed array at 36 degree tilt. Solar generation is assumed to fall entirely between 6 am and 10 pm.
- Based on PGE's data for the Tucannon wind farm in the Columbia Gorge, wind annual capacity factor is assumed to be 36.8%, with 54% of all annual MWh being generated during on-peak hours.
- A Baseload QF is assumed to operate with the same on-peak capacity factor of 91.8% as the avoided CCCT resource.

1. Determine cost per kW per year of representative avoided capacity resource (SCCT).

$/kW-yr	First year capacity cost can be avoided
$ 140.32	2024

2. Calculate first year target payment for the QF's peak capacity contribution ($/kW).

QF resource type	Annual capacity cost of SCCT ($/kW-yr)	Peak Capacity Contribution of QF	Annual capacity cost avoided by QF ($/kW-yr)	**First year target capacity payment to QF ($/kW)**
Baseload	$ 140.32	100.0%	$ 140.32	**$ 140.32**
Wind	$ 140.32	4.2%	$ 5.89	**$ 5.89**
Solar	$ 140.32	13.6%	$ 19.08	**$ 19.08**

3. Convert the target first year capacity payment dollars to a volumetric basis ($/MWh) based on the number of MWh expected to be generated by the QF during on-peak hours.

QF resource type	First year target capacity payment to QF ($/kW)	# On-Peak Hours per Year	QF On-Peak Capacity Factor	# On-Peak Hours QF will Generate	**Volumetric Capacity Payment ($/MWh)**
Baseload	$ 140.32	4,992	91.8%	4,583	**$ 30.62**
Wind	$ 5.89	4,992	28.4%	1,419	**$ 4.15**
Solar	$ 19.08	4,992	27.5%	1,374	**$ 13.89**

4. Determine the total on-peak payment to the QF by adding the energy and capacity payment amounts.

QF resource type	Volumetric Capacity Payment ($/MWh)	Energy Payment from Schedule 37 ($/MWh)	**Total On-Peak Payment ($/MWh)**
Baseload	$ 30.62	$ 39.06	**$ 69.68**
Wind	$ 4.15	$ 39.06	**$ 43.21**
Solar	$ 13.89	$ 39.06	**$ 52.95**

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Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Testimony of Philip Carver

May 22, 2015

Q. PLEASE STATE YOUR NAME AND ORGANIZATION.

A. I am Phil Carver with the Oregon Department of Energy (ODOE). The business address is 625 Marion St. NE, Salem, Oregon. I am the same witness as in ODOE/400 in Phase 1. I am testifying on behalf of ODOE.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. I have a bachelor's degree in economics from the University of California, San Diego (1972) and a Ph.D. in natural resource and utility economics from the Johns Hopkins University (1978).

From 1978 to 1980, I was an assistant professor at Dartmouth College. From 1980 until 2008, I worked for the ODOE. During that time I testified in a number of Oregon Public Utility Commission (OPUC) dockets, including UM 1129, a previous docket relate to implementing section 210 of the federal Public Utility Regulatory Policy Act (PURPA) of 1978.

From November 2008 to July 2009, I was the lead OPUC staff on the Renewable Portfolio standards rulemaking (AR 518). From May 2010 to December 2012, I was a half-time senior policy analyst with the OPUC.

Since then I have worked half-time for ODOE as a senior policy analyst. This work focuses on removing key barriers to generating more renewable power and reducing energy use.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I will address issues number one, five and six from the ALJ memo of March 26, 2015. The other ODOE witness, Diane Broad, will address issues number three, four and nine.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A**.** On issue number one I will describe ODOE's proposal that the qualifying facility (QF) is the party that should own the Green Tags (a.k.a. renewable energy certificates or RECs) during the period of the contract for which the QF is paid market prices.

On issue number five I will describe ODOE's proposal for establishing a contested case docket in parallel with each utility's integrated resource docket in order to resolve issues and assumptions related to calculating the utility's avoided costs.

On issue number six I will describe ODOE's proposal for resolving the question of whether market prices sufficiently compensate for capacity, based on an assessment of the utility's actual purchasing practices as part of the proceeding proposed under issue five.

ISSUE NUMBER ONE

Q. WHO SHOULD OWN THE GREEN TAGS DURING THE LAST FIVE YEARS OF A 20-YEAR FIXED PRICE PPA DURING WHICH PRICES PAID TO THE QF ARE AT MARKET?

A. There is apparent confusion over the interpretation of the following statement from page 1 of Commission Order No. 11-505 as it relates to the last five years of a fixed-price renewable QF contract: “The QF will … transfer those RECs [renewable energy certificates, a.k.a. “green tags”] to the purchasing utility during period of renewable resource deficiency.” While the last five years of the fixed-price renewable contract period could be interpreted as part of the “period of renewable resource deficiency,” the QF is paid only the market price during this period. Applying this interpretation, a QF would transfer the RECs and the power but only be compensated for the power. This would conflict with requirement under PURPA that a utility must pay for all costs that it avoids. Under this interpretation the utility would receive the RECs and avoid compliance costs associated with Oregon’s Renewable Portfolio Standard (RPS), but would not pay the QF for the compliance costs that it avoids.

That the Commission did not intend this outcome can be seen from its statement on page 5 of Commission Order No. 11-505: “If the QF chooses the standard avoided cost stream, it would retain the RECs associated with the energy.” In selecting a 20 year fixed-price renewable PPA the QF is choosing to receive the *standard avoided costs* (i.e. market prices) during the last five years of the contract. Therefore, the QF is entitled to retain the RECs associated with the energy during the last five years of a fixed-price renewable contract.

ISSUE NUMBER FIVE

Q. IS THERE A PROBLEM WITH THE CURRENT PROCESS TO RESOLVE DISPUTES ON THE INPUTS AND ASSUMPTIONS USED TO CALCULATE AVOIDED COSTS?

A. Yes. The current process, where the utility files its avoided cost calculations after the acknowledgement order, does not allow sufficient opportunity to challenge the assumptions in the filing.

Q. PLEASE ELABORATE ON THE PROBLEMS WITH THE CURRENT SYSTEM OF HAVING THE ELECTRIC COMPANY FILE ITS AVOIDED COSTS AFTER THE CONCLUSION OF THE PROCEEDING RELATED TO THE COMPANY'S INTEGRATED RESOURCE PLAN (IRP).

A. While some key issues, such as the date for the next avoidable facility, may be decided in an IRP acknowledgement order, many are not. The acknowledgement order focuses on whether or not to acknowledge action items over the next three or four years. Actions taken beyond that time will be addressed in the next IRP and subsequent proceeding, so the Commission need not assess those actions in the acknowledgement order. The acknowledgement order does not explicitly address most of the input assumptions in the IRP that affect avoided costs. Parties interested in these assumptions do not currently have their "day in court." For example, there was no proceeding to resolve the issue of the proper level of integration costs for a wind QF. The issue is less controversial now, but not as the result of a Commission order.

Q. WHAT SOLUTION DO YOU PROPOSE?

At the same time that an IRP is filed with the Commission, a separate proceeding should begin to address the assumptions affecting avoided cost calculations. This additional proceeding should conclude around the same time as the acknowledgement order.

Q. WHY THIS KIND OF PROCEEDING?

A. ODOE proposes that the Commission require utilities to file avoided cost calculations when they file their IRPs. Parties could ask the Commission to address any disputes related to avoided costs in a proceeding that would run parallel to the IRP proceeding. To start an avoided cost proceeding at the same time as the IRP proceeding would allow parties to challenge the assumptions underlying the calculation of avoided costs, while allowing the avoided costs to be put into place at roughly the same time as the acknowledgement order. By contrast, starting an avoided cost proceeding after the order would result in a delay similar in length to the nine month IRP proceeding, impeding timely implementation of refreshed avoided costs.

The OPUC staff should publish and the Commission should approve a set of minimum filing requirements (MFR) for these avoided cost filings. The MFR should be sufficiently detailed to ensure that filings demonstrate that the assumptions underlying the avoided cost estimates are reasonable. If an input assumption is unresolved at the end of the proceeding, the Commission should choose an estimate that is supported by the preponderance of the evidence.

Q. AVOIDED COSTS FILINGS HAVE BEEN IMPLEMENTED WITHOUT CONDUCTING A SEPARATE CONTESTED CASE PROCEEDING SINCE IRPs WERE BEGUN AROUND 25 YEARS AGO. WHAT HAS CHANGED THAT REQUIRES A NEW PROCEEDING?

A. One big change is the addition of renewable avoided costs, where the QF transfers the RECs to the utility. Calculating a need date for a renewable resource to satisfy the Oregon renewable portfolio standard (RPS) is more complex than calculating a standard need date. Determining this date can depend on a company's future decisions about how to comply with the RPS, some of which may not be appropriate for acknowledgement. Also, more recently the need dates for both standard and renewable avoided costs for some companies are now well beyond the time encompassed by the action plan.

Q. WOULD HAVING A PARALLEL PROCESS BE MORE COSTLY THAN RESOLVING ISSUES AT THE TIME UTILITIES UPDATE AVOIDED COSTS, AFTER THE COMMISSION HAS ISSUED AN IRP ACKNOWLEDGEMENT ORDER?

A. It would not add substantially to the costs, assuming that the non-parallel process were as complete and thorough as the parallel process ODOE is proposing. The key issue is that if the Commission chooses to address these issues after it has issued an acknowledgement order, the updated avoided costs would not be implemented until the conclusion of the subsequent process. Delaying the update would not be timely and would give the utility an undue influence in resolving the controversy.

Q. CAN YOU PROVIDE AN EXAMPLE OF NEW TYPES OF IRP ISSUES THAT ARE NOT RESOLVED IN COMMISSION ACKNOWLEDGMENT ORDERS?

A. Yes, an example can be seen in the IRP filed by PacifiCorp March 31, 2015. The company's preferred portfolio[1] (Table 8.7, IRP page 196, see Exhibit 701, page 1) does not include plans to build or buy new renewable resources through 2034. The IRP assesses renewable resource needs to fulfill the RPS requirements only through 2024 (IRP page 194, see Exhibit 701, pages 2-3). During this period, RPS requirements are met through purchases of unbundled RECs and regular allocations of bundled RECs. The IRP defers any recommendation related to renewable acquisition until the next IRP, at the earliest.

Action Item #1 (Renewable Portfolio Standard Compliance) on page 10 of the IRP states:

> *With a*[n Oregon] *projected bank balance extending out through 2027, defer issuance of RFPs seeking unbundled RECs that will*

[1] Page 186, pages 193-194 and page 10 of http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

qualify in meeting Oregon renewable portfolio standard targets until states begin to develop implementation plans under EPA's draft 111(d) rule, providing clarity on whether an unbundled REC strategy is the least cost compliance alternative for Oregon customers.

Thus the IRP makes no representation about the deficiency date for renewable resources. Nor does it contain information about the likely incremental cost of RPS compliance. Given this, the current PacifiCorp IRP acknowledgement process is unlikely to determine a deficiency date or incremental costs of the RPS. A parallel contested case process would be a better venue to estimate these values.

Q. ARE THERE OTHER ISSUES THAT HAVE EMERGED SINCE IRPs WERE INSTITUTED THAT REQUIRE A PARALLEL PROCESS FOR DETERMINING AVOIDED COST?

A. Yes. As noted above, wind integration costs have been contentious in the past. In relation to standard avoided costs, assigning the appropriate capacity credit for variable renewable generation has become contentious. While the OPUC has opened dockets to address this issue (UM 1716 and UM 1719), it is likely that different assumptions will be needed for different companies. It would be unusual for the Commission to rule on this kind of technical assessment in an acknowledgement order.

In the future parties may also have disputes over how to apply issues that are addressed outside the IRP process. For example, docket UM 1719 will address how capacity credits for wind and solar resources should be calculated in IRPs. It will not address how capacity credits should be calculated for standard (10 MW and under) QF contracts.

Also, the Commission in Order No. 14-058 decided that transmission costs to a company associated with a “load pocket” be assigned to the Qualifying Facility (QF) and avoided costs be adjusted accordingly.[2] ODOE witness Diane Broad addresses this issue in her testimony.

Whether or not a particular delivery point is in a load pocket is an empirical question, and the answer will change over time. Such a determination is not likely to be adequately addressed in an acknowledgement order. It would be best addressed in the parallel proceeding that ODOE recommends.

Q. IS THERE ANOTHER ISSUE THAT ODOE WILL RAISE IN THIS PROCEEDING THAT MIGHT BE BETTER ADDRESSED IN A PARALLEL PROCEEDING?

A. Yes. The issue of whether a utility used appropriate forecasts of market prices in avoided cost calculations in their IRPs is also not likely to be addressed adequately in the IRP Order. ODOE suggests below that whether or not a particular price forecast is appropriate should be treated as an empirical question that depends on a utility’s actual purchasing practices (see ODOE response to Issue number six below).

[2] [2] “*We anticipate asking parties to recommend how third-party transmission costs to transport QF output from receipt in a load pocket to load should be accounted for in standard contracts; for example, by lowering avoided standard avoided cost rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means.”* Order No. 14-058, pp. 22-23. This is issue number nine in this docket which is addressed by ODOE witness Diane Broad.

ISSUE NUMBER SIX

Q. DO MARKET PRICES USED DURING THE RESOURCE SUFFICIENCY PERIOD SUFFICIENTLY COMPENSATE FOR CAPACITY?

A. The answer depends on how market prices are forecast and whether that forecast accurately reflects the actual purchasing practices of a utility.

When a utility files its avoided cost prices with the Commission, it includes a forecast of the market price during the Resource Sufficiency Period. This forecast is typically taken from the IRP. Whether these prices accurately reflect the costs the utility would avoid depends upon the utility's actual purchasing practices. For example, a utility might use a forecast of Mid-Columbia monthly wholesale power prices. However, if it typically purchases capacity separately from its energy purchases or if it contracts for a longer term at fixed prices, this forecast is unlikely to reflect the costs the utility will actually avoid. Whether or not a utility's forecast reflects its actual practices is an empirical question that could be determined in a proceeding that would parallel the IRP proceeding, as discussed in the answers to issue number five above.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DOCKET NO. UM 1610
Phase 2
EXHIBIT: ODOE/701
WITNESS: PHILIP CARVER

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY
Exhibit 701
Accompanying the Testimony of
Philip Carver

May 22, 2015

ODOE/701
Carver/1

Table 8.7, page 196 of Volume 1 of PacifiCorp's 2015 Integrated Resource Plan

Table 8.7 – PacifiCorp's 2015 IRP Preferred Portfolio

Preferred Portfolio (Case C05a-3Q)		Nameplate Capacity (MW)																				Resource Totals 1/	
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	(33)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	(269)
	Huntington 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	(450)
	Carbon 1 (Coal Early Retirement/Conversions)	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon 2 (Coal Early Retirement/Conversions)	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	(50)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	(358)
	Coal Ret_AZ - Gas RePower	-	-	-	-	-	-	-	-	-	-	387	-	-	-	-	-	-	-	-	-	-	387
	Coal Ret_WY - Gas RePower	-	-	-	337	-	-	-	-	-	-	-	-	-	-	-	(337)	-	-	-	-	337	-
	Expansion Resources																						
	CCCT - DJohns - F 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	313	-	-	-	-	-	313
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	423
	CCCT - Utah-N - F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	635	635	-	1,270
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	-	-	-	-	846
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	1,159	-	-	635	635	-	2,852
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9	-	-	4.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9	-	-	4.9
	DSM, Class 2, ID	4	4	5	5	5	4	4	4	5	5	5	5	5	5	5	4	4	4	5	4	45	90
	DSM, Class 2, UT	69	78	84	86	92	81	84	90	91	93	75	76	80	80	77	75	72	72	73	70	847	1,596
	DSM, Class 2, WY	6	8	10	12	14	12	13	14	15	16	13	13	14	15	15	15	16	16	17	17	121	271
	DSM, Class 2 Total	79	90	99	102	111	97	101	108	110	114	92	94	99	99	97	94	93	92	94	92	1,012	1,958
	FOT Mona Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	161	44	110	104	268	300	74	-	53
West	**Expansion Resources**																						
	Oregon Solar Capacity Standard	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	10.6	-	-	10.6	-	-	10.6	-	-	-	-	-	10.6	31.8
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	5.0	-	-	-	-	-	-	-	-	-	-	-	-	5.0	5.0
	DSM, Class 1 Total	-	-	-	-	-	-	-	5.0	10.6	-	-	10.6	-	-	10.6	-	-	-	-	-	15.6	36.8
	DSM, Class 2, CA	1	2	2	2	2	1	1	2	2	2	1	1	1	1	1	1	1	1	1	1	16	29
	DSM, Class 2, OR	44	39	36	33	29	27	25	25	23	23	21	22	22	22	21	21	20	21	20	20	303	511
	DSM, Class 2, WA	8	9	10	10	11	9	10	10	11	11	9	9	9	9	9	8	8	8	8	7	98	181
	DSM, Class 2 Total	54	49	47	44	42	38	36	36	36	35	31	32	32	32	31	30	29	30	28	28	417	721
	FOT COB Q3	-	62	29	-	60	104	-	-	-	-	-	-	-	268	248	268	268	268	185	138	26	95
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	227	375	375	370	375	375	269	291	261	254	271	292	335	375	375	375	375	375	375	375	317	335
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	Existing Plant Retirements/Conversions	(222)	-	-	57	-	-	-	-	-	-	-	-	-	(762)	-	(1,144)	(77)	-	(627)	-		
	Annual Additions, Long Term Resources	133	146	146	146	153	135	137	149	157	149	123	137	130	555	139	1,284	122	122	762	755		
	Annual Additions, Short Term Resources	727	937	904	870	935	979	769	791	761	754	771	792	835	1,304	1,167	1,253	1,247	1,411	1,360	1,087		
	Total Annual Additions	860	1,084	1,050	1,016	1,088	1,113	906	941	917	903	893	928	965	1,859	1,305	2,537	1,369	1,533	2,123	1,841		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Page 194, Vol. 1 of the 2015 PacifiCorp IRP

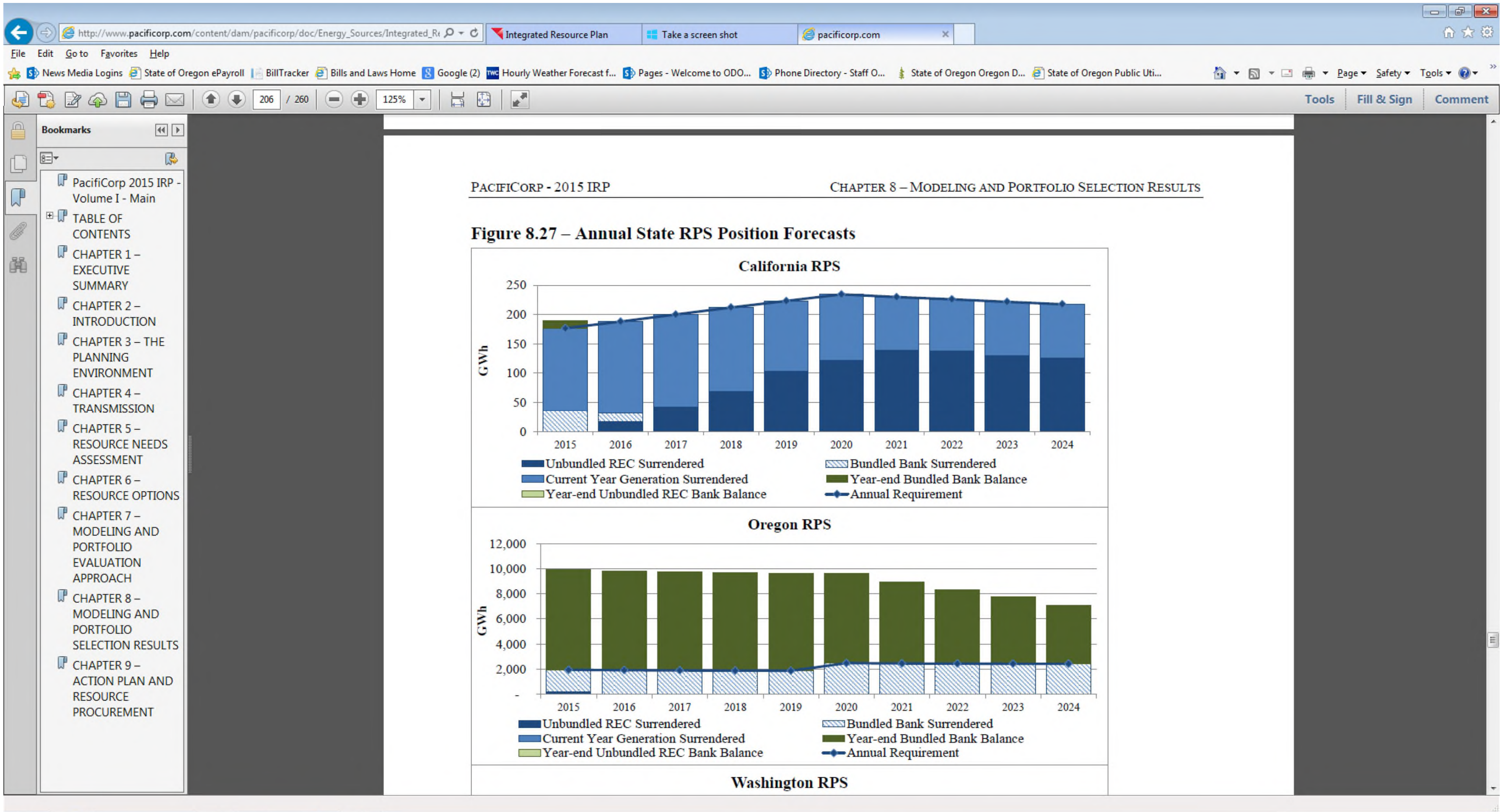
PACIFICORP - 2015 IRP CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

Figure 8.27 – Annual State RPS Position Forecasts

Page 194, Vol. 1 of the 2015 PacifiCorp IRP, continued

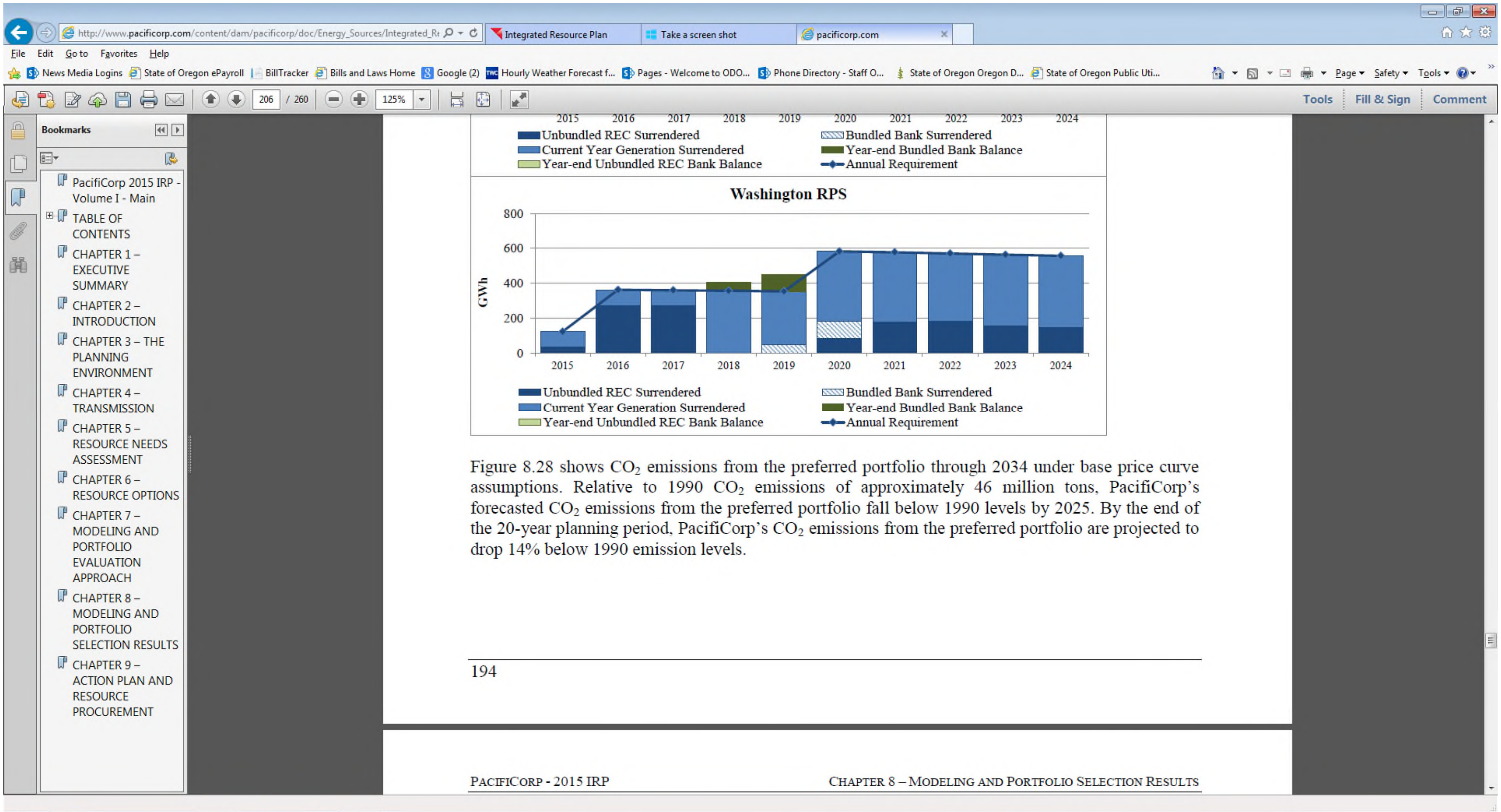

Figure 8.28 shows CO_2 emissions from the preferred portfolio through 2034 under base price curve assumptions. Relative to 1990 CO_2 emissions of approximately 46 million tons, PacifiCorp's forecasted CO_2 emissions from the preferred portfolio fall below 1990 levels by 2025. By the end of the 20-year planning period, PacifiCorp's CO_2 emissions from the preferred portfolio are projected to drop 14% below 1990 emission levels.