Davison Van Cleve PC
TEL (503) 241-7242 • FAX (503) 241-8160 • mail@dvclaw.com
Suite 400
333 SW Taylor
Portland, OR 97204

May 27, 2014

Via Electronic Mail and Federal Express

Public Utility Commission of Oregon
Attn: Filing Center
3930 Fairview Industrial Drive SE
Salem OR 97302

Re: In the Matter of PORTLAND GENERAL ELECTRIC
Net Variable Power Costs (NVPC) and
Annual Power Cost Update (APCU)
Docket No. UE 286

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the original and five (5) copies of the redacted Opening Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities. Also enclosed are the original and five (5) copies of the confidential pages of same, which are being filed under seal pursuant to Protective Order No. 14-043.

Thank you for your assistance. If you have any questions, please do not hesitate to contact our office.

Sincerely,

Jesse O. Gorsuch

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the attached **Opening Testimony and Exhibits of Bradley G. Mullins** upon all parties in this proceeding, as shown below, by sending a copy via electronic mail and by sending the confidential pages of same to all qualified persons via First Class U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 27th day of May, 2014

Sincerely,

Jesse O. Gorsuch

(W) CITIZENS' UTILITY BOARD OF OREGON
OPUC DOCKETS
ROBERT JENKS
G. CATRIONA MCCRACKEN
610 SW BROADWAY STE 400
PORTLAND OR 97205
dockets@oregoncub.org
bob@oregoncub.org
catriona@oregoncub.org

(W) OREGON PUBLIC UTILITY COMMISSION
JOHN CRIDER
PO BOX 1088
SALEM OR 97308-1088
john.crider@state.or.us

(W) PUC STAFF - DEPARTMENT OF JUSTICE
STEPHANIE S. ANDRUS
MICHAEL T. WEIRICH
BUSINESS ACTIVITIES SECTION
1162 COURT ST NE
SALEM OR 97301-4096
stephanie.andrus@state.or.us
michael.weirich@doj.state.or.us

(W) PACIFIC POWER
SARAH WALLACE
825 NE MULTNOMAH ST., STE 1800
PORTLAND OR 97232
sarah.wallace@pacificorp.com

(W) NOBLE AMERICAS ENERGY SOLUTIONS, LLC
GREG BASS
401 WEST A ST., SUITE 500
SAN DIEGO CA 92101
gbass@noblesolutions.com

(W) PACIFICORP, DBA PACIFIC POWER
OREGON DOCKETS
825 NE MULTNOMAH ST., STE 2000
PORTLAND OR 97232
oregondockets@pacificorp.com

(W) NORTHWEST NATURAL
E-FILING
MARK R. THOMPSON
220 NW 2ND AVE
PORTLAND OR 97209
efiling@nwnatural.com
mark.thompson@nwnatural.com

(W) PORTLAND GENERAL ELECTRIC
DOUGLAS C. TINGEY
121 SW SALMON ST 1WTC1301
PORTLAND OR 97204
doug.tingey@pgn.com

(W) PORTLAND GENERAL ELECTRIC
JAY TINKER
121 SW SALMON ST 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com

(W) RICHARDSON ADAMS, PLLC
GREGORY M. ADAMS
P.O. BOX 7218
BOISE ID 83702
greg@richardsonadams.com

(W) ENERGY STRATEGIES LLC
KEVIN HIGGINS
215 STATE ST – SUITE 200
SALT LAKE CITY UT 84111-2322
khiggins@energystrat.com

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 286

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU)	)
	)
	)

REDACTED OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

May 27, 2014

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant representing industrial customers throughout the western United States. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"), a non-profit trade association whose members are large customers served by electric utilities throughout the Pacific Northwest, including Portland General Electric Company ("PGE" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and in Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked at Deloitte Tax, LLP, where I was a Tax Senior providing tax consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters primarily involving power supply costs. I began performing independent consulting services in September 2013. A further description of my educational background and work experience can be found in Exhibit ICNU/101.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the Company's Net Variable Power Costs ("NVPC") and Annual Power Cost Update ("APCU") filing for 2015. The Company initially included the APCU filing for 2015 in its 2014 Request for a General Rate Revision (the "2014 GRC"), UE 283, where it forecast NVPC of $576.1 million.[1/] After the Oregon Public Utility Commission ("Commission") bifurcated the Company's 2014 GRC and APCU filings, the Company filed a Multi-area Optimization Network Energy Transaction ("MONET") model update, on April 1, 2014, where it forecast 2015 NVPC of $573.1 million, or $3.0 million less than its initial filing.

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony will make the following recommendations:

1. **Wind Integration.** The Commission should require the Company to calculate NVPC as if it elected to self-supply wind integration services for the entire test period. This adjustment will allow customers to receive the full integration benefits promised from the Port Westward II facility contemporaneous to when that plant is included in rates, reducing NVPC by $5.0 million.

2. **Beaver PTP Transmission Contract.** The Commission should require the Company to exclude certain costs associated with its Beaver point-to-point ("PTP") transmission contract with the Bonneville Power Administration ("BPA") on the basis that a portion of the transmission capacity under this contract is no longer used and useful. This adjustment will reduce NVPC by $6.7 million.

3. **Tucannon River Capacity Factor.** The Commission should require the Company to update the capacity factor for the Tucannon River Wind Facility ("Tucannon River") in the MONET model to reflect a new wind study commissioned by the Company. This change will allow customers to receive the benefit of the most up-to-date information known at this time, reducing NVPC by $1.2 million.

1/ This value is from the study that included Tucannon River for the entire test period. The $580.2 million value reported in PGE/500 assumed Tucannon River commenced operation in April 2015.

4. **Tucannon River Transmission Credits.** The Commission should require the Company to include transmission credits associated with Tucannon River in January and February of the test period. This correction reduces NVPC by $789,786.

5. **Start-up and Shut-down Costs.** The Commission should require the Company to remove start-up costs that occur in the first hours of the study period, and shut-down costs that occur in the final hours of the study period. This adjustment will correct the MONET modeling assumption that all plants are turned-off immediately prior and subsequent to the study period, reducing NVPC by $148,601.

6. **Montana Non-firm Wheeling.** The Commission should require the Company to correct its calculation of non-firm wheeling on the Montana Intertie to better reflect historical usage. This correction reduces NVPC by $381,799.

7. **Montana Beneficial Use Tax.** The Commission should require the Company to correct its calculation of Montana beneficial use taxes to better reflect the amount assessed historically. This correction reduces NVPC by $902,545.

Q. HAVE YOU PREPARED A TABLE TO SUMMARIZE YOUR NVPC RECOMMENDATION IN THIS PROCEEDING?

A. Yes. The following table summarizes my NVPC recommendation.

TABLE 1
SUMMARY OF NVPC RECOMMENDATION

Company Proposed NVPC (April 1, 2014 Update):		$ 573,054,000
1. Wind Integration	$ (5,075,904)	
2. Beaver Point-to-Point Contract	(6,716,115)	
3. Tucannon River Capacity Factor	(1,201,100)	
4. Tucannon Transmission Credits	(789,786)	
5. Start-up and Shut-down Costs	(148,601)	
6. Montana Intertie Non-firm Wheeling	(381,799)	
7. Montana Beneficial Use Tax	(902,545)	
Total Adjustments:		$ (15,215,850)
Recommended NVPC:		$ 557,838,150

II. WIND INTEGRATION

Q. WHAT ADJUSTMENT ARE YOU PROPOSING RELATED TO WIND INTEGRATION?

A. I propose that the Commission require the Company to assume in its NVPC calculations that it had elected the most cost-effective method to integrate wind for the entire test period. Specifically, I propose that NVPC be calculated as if the Company had elected to self-integrate the Biglow and Tucannon River facilities, resulting in a $5.0 million reduction to NVPC.

Q. WHAT IS YOUR BASIS FOR PROPOSING THIS ADJUSTMENT?

A. The evidence shows that the Company has not prudently managed its integration costs. There are two fact patterns that lead to this conclusion. First, the Company justified the cost of the Port Westward II facility on the basis that it would be used to self-integrate wind, yet it has failed to take the necessary steps to self-integrate by the time the facility will be placed into service. Second, despite parties' promptings in the prior APCU proceeding for the Company to develop a more cost-effective wind integration paradigm, the Company did not properly analyze, and plan for, its April 4, 2014 balancing service election, which impacts the first nine months in the test period. In fact, the Company has not shown that it has made sufficient progress in preparing its systems to self-integrate wind in time for BPA's next balancing service election.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE OPTIONS AVAILABLE TO THE COMPANY TO INTEGRATE WIND.

A. Both the Biglow and Tucannon River wind facilities are located in BPA's balancing area. Thus, the Company must pay BPA ancillary service charges, including charges for both Variable Energy Resource Balancing Service ("VERBS") and Generation Imbalance

("GI"), to integrate these wind resources on its behalf. Over the past five years, and in particular following the settlement approved in the BP-14 rate proceeding on May 15, 2013, BPA has given companies that own variable energy resources, such as wind resources, additional flexibility regarding how they procure integration services. These companies, including PGE, now have the option to pay discounted VERBS rates in return for electing to schedule on a sub-hourly basis,[2/] and also have the option to self-supply integration services for VERBS and/or GI.

The election for these integration options traditionally occurs every two years, corresponding to BPA's rate periods; however, in BP-14, entities were given the option to make a special, mid-rate-period election outside of the two-year window, which occurred on April 4, 2014, and will be effective for BPA's fiscal year 2015 (October 2014 – September 2015). The next election will occur for the BP-16 rate period in April 2015, and unless a similar mid-rate-period election is given, it will be in effect for the entire BP-16 rate period – BPA fiscal years 2016 and 2017 (October 2015 – September 2017).

Q. WAS THE COMPANY AWARE OF ITS ABILITY TO ELECT TO SELF-SUPPLY IN THE APRIL 4, 2014 MID-RATE-PERIOD ELECTION?

A. Yes. In the Company's prior APCU filing, Renewable Northwest ("RNW") witnesses Yourkowski, Lindsay, and Dubson criticized the Company for not electing the most cost-effective method to integrate wind in its April 2013 balancing service election and called attention to the Company's ability to make a new, more cost-effective election in its April

[2/] While discounted rates only apply to the VERBS ancillary service charges, it is expected that an entity electing sub-hourly scheduling will likely also incur fewer GI charges as a result of using sub-hourly forecasts.

4, 2014 mid-rate-period election.[3/] While no NVPC adjustment was incorporated into the final settlement in that proceeding, the Company agreed to perform a comprehensive study of its April 4, 2014 election and present its analysis to parties prior to making the election.[4/]

Q. DID THE COMPANY FULFILL ITS OBLIGATION TO ANALYZE AND SELECT THE MOST COST-EFFECTIVE METHOD TO INTEGRATE WIND IN ITS APRIL 4, 2014 ELECTION?

A. No. While the stipulation required the Company to perform a comprehensive review of both the costs and benefits of each alternative method, the Company only performed quantitative analysis on one alternative option, the thirty-minute scheduling election.[5/] Confidential Exhibit ICNU/102 contains the presentation that the Company provided to parties prior to its April 4, 2014 balancing service election.[6/] Notably, the presentation fails to provide a comprehensive review of the Company's wind integration options. In addition, despite the thirty-minute scheduling option being more cost-effective than the sixty-minute scheduling election, the Company did not pursue it for the benefit of customers. The Company viewed the benefits associated with the thirty-minute scheduling option, which amounted to nearly $[redacted] per year, to be inadequate to justify participation.[7/] Other options were not even quantified on an analytical basis.[8/] The Company stated that it did not analyze a fifteen-minute scheduling election as a

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3/ Docket No. UE 266, RNP/100 Yourkowski-Lindsay-Dubson at 5:8-6:3 and 9:21-10:4 (May 21, 2013).
4/ Docket No. UE 266, Order No. 13-280 at 8-9.
5/ See Confidential Exhibit ICNU/102 at 9.
6/ It should be noted that the March 18, 2013 date detailed on the slide deck is incorrect. The actual date of the presentation was March 18, 2014.
7/ See Confidential Exhibit ICNU/102 at 14; see Confidential Table 2 below.
8/ See Confidential Exhibit ICNU/102 at 4, 13.

result of "modeling difficulties"[9/] and that it did not analyze the self-integration option because the necessary system upgrades were not in place to make such an election.[10/]

Q. PLEASE DESCRIBE WHAT ELECTION THE COMPANY MADE IN ITS MID-RATE-PERIOD ELECTION AND WHY YOU BELIEVE THAT ELECTION WAS NOT THE MOST COST-EFFECTIVE OPTION?

A. In its April 4, 2014 mid-rate-period election on balancing services, the Company elected to purchase all wind integration services from BPA under a sixty-minute scheduling paradigm. This election represents no change in how the Company has traditionally procured wind integration. Table 2, below, demonstrates why this election is not the most cost-effective method to integrate wind. As can be seen in the table, the election that the Company made is the most expensive option available.

CONFIDENTIAL TABLE 2
ESTIMATED TEST PERIOD WIND INTEGRATION COSTS
Under alternative balancing service elections ($million)

[redacted]

9/ Id. at 13.
10/ Id. at 9.

Q. WHY IS THE FACT THAT THE COMPANY DID NOT HAVE THE PROPER SYSTEM UPGRADES IN PLACE INSUFFICIENT TO JUSTIFY ITS DECISION NOT TO ANALYZE THE SELF-INTEGRATION OPTION?

A. The various hurdles that allegedly prevented the Company from making a cost-effective election should have been resolved well in advance of its mid-rate-period election. It is not sufficient to say that an option was not viable on the basis that the Company did not know how to analyze it, and if system upgrades were indeed necessary, those upgrades should have been identified and quantified early enough to provide time to place them in service prior to the effective date of the mid-rate-period election. I will note that the Company would not have been the first entity to pursue a self-integration option. Iberdrola Renewables, LLC has successfully self-integrated its variable energy resources in BPA's balancing area since October 2010, and is seeking to expand its self-integration program to other entities.[11/] Thus, it is clear that self-integration is achievable.

Q. WHAT OTHER FACTORS SUGGEST THAT THE COMPANY SHOULD HAVE BEEN CAPABLE OF SELF-INTEGRATING ITS VARIABLE ENERGY RESOURCES IN TIME FOR THE APRIL 4, 2014 ELECTION?

A. A major reason why the Company should have been preparing to self-integrate its variable energy resources in time for the April 4, 2014 election is that Port Westward II was justified based on its ability to be used to self-integrate wind. In fact, a significant factor in the Company's decision to select Port Westward II through its 2012 Request for Proposals for Capacity and Baseload Energy Resources ("Capacity RFP") was Port Westward II's ability to allow the Company to self-integrate.

[11/] See FERC Docket No. ER13-1058-000.

The Capacity RFP assumed a need for a resource "that will fill the dual function of providing capacity to maintain supply reliability … *while also providing needed flexibility to address variable load requirements and increasing levels of intermittent energy resources*."[12/] The Company also modeled the flexible capacity bids in the Capacity RFP under the assumption that all wind would be self-integrated: "Flexible Capacity bids will be subject to a reliability based dispatch required to follow expected load or wind deviations …."[13/]

Without wind-integration, MONET only models Port Westward II to dispatch in 13 percent of the hours of the year. In contrast, the Capacity RFP assumed Port Westward II would dispatch in 74 percent of hours in 2015.[14/] Had the Company modeled Port Westward II solely on economic dispatch, the results of the Capacity RFP likely could have been different. Flexible capacity bids from combined cycle combustion turbine ("CCCT") technologies were not accepted in the Capacity RFP on the basis that they did not meet the Company's flexible capacity needs, yet, because a CCCT has a lower variable cost, it is possible that such a resource would have been selected over Port Westward II if the need to self-integrate wind was not considered.[15/] It, therefore, appears that the economics of Port Westward II are dependent on it being used for self-integration. Thus, I believe that the Company has the obligation to ensure that customers receive the full benefits of Port Westward II on the same basis that its cost was justified in the Capacity RFP. This means the Company's NVPC should be reduced to reflect the

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[12/] Docket No. UM 1535, Capacity RFP at 1 (emphasis added) (Jan. 25, 2012).
[13/] Id. at 30.
[14/] Id. at 81.
[15/] Id. at 2.

benefits customers would be receiving if the Company had elected to self-integrate. If these benefits are not provided for the resource's entire useful life, customers are effectively over-paying for Port Westward II.

Q. DOES THE COMPANY ASSUME SELF-INTEGRATION AT ANY POINT DURING THE TEST YEAR?

A. Yes. At PGE/500, Page 12, lines 12-16, the Company states that it will self-integrate starting in Q4 of the test year. By proposing such an adjustment, the Company tacitly acknowledges the need to include self-integration benefits in rates as a result of the Port Westward II acquisition. Unfortunately, a Q4 benefit is too little too late, given the low dispatch rate of Port Westward II without self-integration. Further, even the Q4 adjustment proposed by the Company does not adequately pass the full amount of benefits back to customers.

Q. WHY DO YOU BELIEVE THAT THE COMPANY'S Q4 PORT WESTWARD II INTEGRATION ADJUSTMENT IS INADEQUATE?

A. In MONET, the Company only included self-integration benefits for the Biglow facility and excluded Tucannon River. This reduces benefits to customers by $828,886, despite the fact that, with Port Westward II online, the Company has sufficient flexible capacity to integrate both wind facilities. Given the magnitude of the benefits to ratepayers, the Company should have been working with BPA to ensure that it is capable of self-integrating Tucannon River when that resource comes online.

Q. ARE THERE ANY OTHER DEFICIENCIES WITH THE COMPANY'S Q4 SELF-INTEGRATION MODELING?

A. Yes. The Company used the wind integration rate for 2018, not the wind integration rate for 2015. Wind integration rates typically possess a relationship to gas prices. Because gas prices included in the test period are approximately 22 percent lower than 2018 gas prices assumed in the 2013 Wind Integration Study included in the Company's 2013 IRP, wind integration costs in the test period should also be lower. Based on this 22 percent difference in gas prices, the wind integration cost for 2015 is likely approximately $3.13/MWH, compared to $3.99/MWH calculated for 2018.

Q. PLEASE SUMMARIZE HOW YOU HAVE CALCULATED YOUR ADJUSTMENT.

A. My adjustment, which is detailed in Confidential Exhibit ICNU/103, removes all BPA wind integration costs from the test period and replaces those costs with the cost of self-integrating all of the Company's wind resources (Biglow and Tucannon River) as calculated in the Company's 2013 Wind Integration Study. Rather than using the wind integration rate for 2018, however, I have used a rate estimated for 2015 of $3.13/MWH. In total, this reduces NVPC by $5,075,904.

III. BEAVER POINT-TO-POINT CONTRACT

Q. WHAT ADJUSTMENT YOU ARE PROPOSING RELATED TO THE BEAVER POINT-TO-POINT CONTRACT?

A. I propose an adjustment that removes the costs associated with the unused portion of the Beaver PTP transmission contract on the basis that it is not used and useful. This adjustment results in a $6.7 million reduction to NVPC.

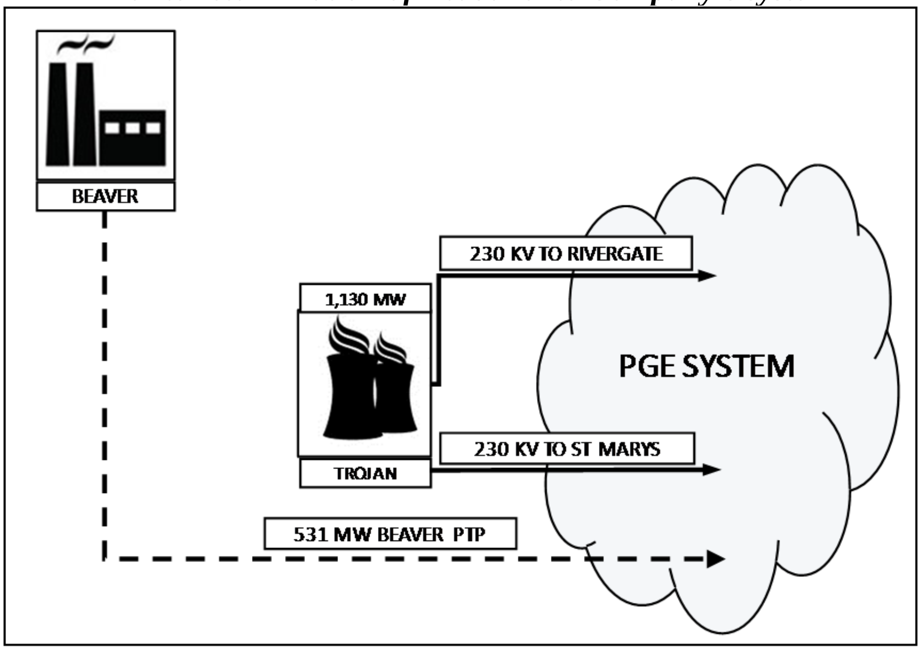
Q. WHAT IS YOUR BASIS FOR SUGGESTING THAT THE BEAVER PTP TRANSMISSION CONTRACT IS NOT USED AND USEFUL?

A. The Company originally used the Beaver PTP transmission contract to deliver power from the Beaver generating station to load. Following the construction of Port Westward, the Company reterminated the Beaver power facility to the Trojan transmission substation. This connected Beaver directly into the Company's system and eliminated the need to purchase additional transmission from BPA. The Company has recently renewed the Beaver PTP contract for the five-year period beginning on January 1, 2015, and ending on December 31, 2020. Because Beaver is now interconnected into the Company's system, the full amount of this contract is not needed, is not used and useful, and the Company's decision to renew the full amount of capacity with BPA was not prudent. Accordingly, the costs associated with the unused portion of this contract should be removed from rates for the entire term of the contract.

Q. PLEASE PROVIDE SOME BACKGROUND ON HOW THE BEAVER PTP TRANSMISSION CONTRACT WAS ORIGINALLY USED?

A. The Beaver PTP contract is a 531 MW transmission agreement with BPA that the Company historically used to wheel power from the Beaver facility to Portland area loads. The transmission was originally configured as demonstrated in Figure 1 below.

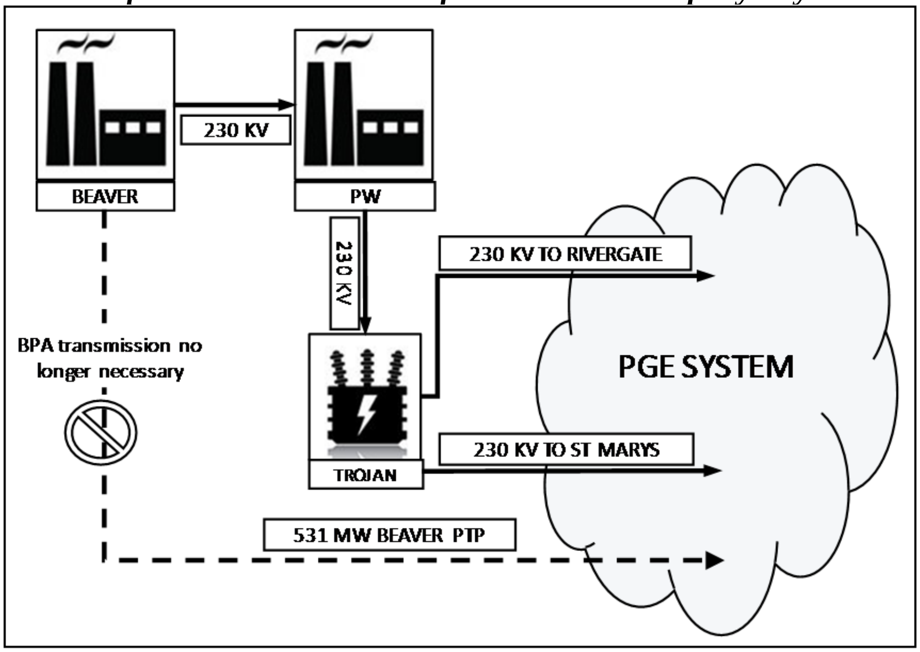
FIGURE 1
DIAGRAM OF HISTORICAL TRANSMISSION FROM BEAVER
Prior to retermination of Beaver onto Company's system



Q. HOW DID THE TRANSMISSION REQUIREMENTS FOR BEAVER CHANGE FOLLOWING THE DECOMMISSIONING OF TROJAN AND CONSTRUCTION OF PORT WESTWARD?

A. Following the decommissioning of Trojan in the early 1990s, and the construction of Port Westward and associated transmission to the Trojan substation in 2007, it was possible to interconnect Beaver directly into the Company's system as a result of its proximity to Port Westward. Figure 2, below, demonstrates how transmission was configured from the Beaver facility following its interconnection into the Company's system. As can be seen from the diagram it was no longer necessary to procure transmission from BPA to deliver power from Beaver to Portland area loads.

FIGURE 2
DIAGRAM OF CURRENT TRANSMISSION FROM BEAVER
Subsequent to retermination of Beaver onto Company's system



Q. HOW DOES THE ACQUISITION OF PORT WESTWARD II IMPACT THE CAPACITY FROM THE BEAVER PTP CONTRACT?

A. Port Westward II will likely require some BPA transmission in order to deliver power from the Trojan substation into loads. The amount of Company-owned transmission from Trojan is likely inadequate to service all three plants located in near Clatskanie – Beaver, Port Westward and Port Westward II – once Port Westward II is placed into service.

Q. HAVE YOU ACCOUNTED FOR BPA TRANSMISSION ASSOCIATED WITH PORT WESTWARD II IN YOUR ADJUSTMENT?

A. Yes. I have assumed that 216 MWs of the Beaver PTP Contract will be used to deliver power from Port Westward II. While the Company-owned transmission, which was originally used to service the 1,130 MW Trojan power plant, should be capable of delivering power from Beaver and Port Westward, Port Westward II was evaluated in the Capacity RFP based on the assumption that it would use BPA wheeling to deliver power to loads. My assumption is that the 216 MW nameplate capacity of Port Westward II will be designated on the Beaver PTP Contract. Given the fact that the Company recently renewed the contract and had the option to reduce the amount of capacity purchased, however, the remaining 315 MW should not be included in rates on the basis of both the used and useful and prudence ratemaking principles.

IV. TUCANNON RIVER CAPACITY FACTOR

Q. PLEASE EXPLAIN YOUR PROPOSAL TO USE AN UPDATED CAPACITY FACTOR FOR THE TUCANNON RIVER WIND FACILITY?

A. The Company's filing assumes that the capacity factor for Tucannon River in the test period will be 36.8 percent, which was based on the value used to evaluate the Tucannon River site in the 2012 Request for Proposals for Renewable Resources ("Renewable RFP")[16/]. As a result of changes to the Tucannon River site layout, however, the Company has developed a new wind study that forecasts a better, [redacted] percent, capacity factor for the Tucannon River facility.[17/] The Company claims that this new wind study is a draft and should not be used until construction of the turbine foundations has been completed.[18/] I disagree and propose to use the capacity factor from the new wind study, which results in a reduction of $1.2 million to NVPC.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE NEW WIND STUDY.

A. Following the Renewable RFP, the Company made substantial changes to the turbine layout at the Tucannon River site. These changes were detailed in Attachment A to the

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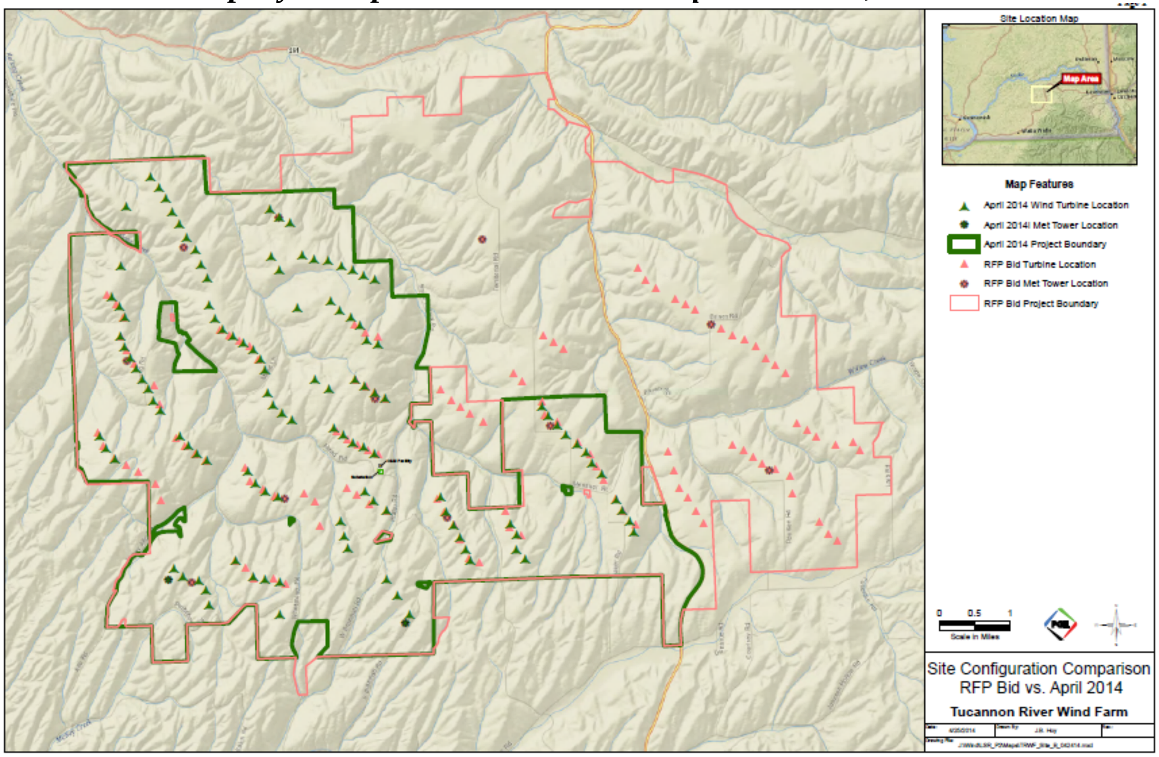
16/ Docket No. UM 1613
17/ See Confidential Exhibit ICNU/104.
18/ Id.

Company's Response to ICNU Data Request No. 041, which has been represented in Figure 3, below. The pink (light) outline represents the layout as it was assumed in the Renewable RFP and the green (bold) outline represents the site layout as it exists today.

FIGURE 3
TUCANNON RIVER SITE LAYOUT CHANGES FOLLOWING RFP
From Company's Response to ICNU Data Request No. 041, Attachment A



Based on this figure, it appears that approximately 52 of the 116 wind turbines have been repositioned within the site to a location that is substantially different than originally proposed in the Renewable RFP. Due to the nature of these site changes, the Company hired an independent consulting firm to perform a new wind study to better reflect the site's potential.

Q. WHY DOES THE COMPANY NOT RELY ON THIS NEW STUDY?

A. The Company does not rely on the new study because it says it is waiting to commission yet another study once the turbine foundations have been poured.[19] The Company seems to suggest that the new study is not yet reliable. However, one wonders why the Company commissioned the most recent wind study at all if it does not think it is reliable. In fact, the new wind study has been revised three times since it was originally issued, on April 30, 2013. The expected capacity factor included in each revision ranged between [redacted] and [redacted] percent on the basis of nameplate capacity, which indicates that the expected capacity factor at Tucannon River wind study is reliable at this point.

Furthermore, the fact that the new study is labeled as a "draft" is no reason to discount it. It appears to be common practice for this type of study to carry a "draft" label, despite being complete and substantially final. For example, even the DNV KEMA Renewables, Inc. ("DNV KEMA") report that was used in the Renewable RFP, and that the Company has relied on in its filing to calculate the 36.8 percent capacity factor, was labeled as a "draft."[20] Certainly, if the Company's filing already uses a wind study that is labeled "draft," it is insufficient to say that the new study should not be used simply because it, too, is labeled "draft."

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL THAT THE NEW WIND STUDY SHOULD ONLY BE USED ONCE ALL OF THE TURBINE FOUNDATIONS HAVE BEEN LAID?

A. No. By making this proposal, the Company seems to indicate that it is not yet certain of where the turbines will be located in its final site layout, and that therefore, the latest

[19] See PGE/500, Niman –Paschka – Hager at 13, lines 16-18.
[20] See Exhibit ICNU/105.

revision of the new wind study is somehow inadequate. Given that the Company is expected to complete construction of the facility by the end of 2014, I find it to be difficult to believe that the Company is not yet certain of what the final site layout will be. Notwithstanding this, the site layout analyzed in the most recent revision of the new wind study appears to be substantially the same as the latest site layout presented in Figure 3 and, at a minimum, is a better reflection of the site layout than the DNV KEMA report, which, as Figure 3 demonstrates, was based on a substantially different site footprint.

Q. DO YOU AGREE THAT THE COMPANY SHOULD BE ALLOWED TO UPDATE THE CAPACITY FACTOR IF IT MAKES A REVISION TO THE NEW WIND STUDY BY OCTOBER 2014?

A. No. While I do not think the Company should be foreclosed from updating the capacity factor to reflect revisions to the wind study in later APCU filings, if an updated capacity factor is incorporated at such a late stage in this proceeding, parties will not have the opportunity to do a full review of the updated study.

Q. WILL YOU PLEASE SUMMARIZE WHY YOU BELIEVE THE NEW WIND STUDY SHOULD BE USED?

A. The new wind study should be used because it is based on the most up-to-date information known at this time. If the outdated DNV KEMA wind study is used, it will reflect a site layout that is substantially different than what the Company will actually construct, and customers will not receive the benefit of apparent improvements that the Company has made to the Tucannon River site. For this proceeding, I propose that the latest revision of the new study be used. If the study is subsequently revised, the Company should be permitted to include that update in future APCU filings.

V. TUCANNON RIVER TRANSMISSION CREDIT

Q. PLEASE DESCRIBE THE CORRECTION RELATED TO BPA TRANSMISSION CREDITS FOR TUCANNON RIVER.

A. The Company is entitled to BPA transmission credits as a result of funds that were advanced to construct the interconnection substation at Tucannon River. These credits offset the amount the Company pays to BPA for PTP service from Tucannon River. The Company included BPA transmission credits in March through December of the test period, but excluded them in January and February. I propose a correction that applies the BPA transmission credits in January and February of the test period, resulting in a $789,786 reduction to NVPC.

Q. DID THE COMPANY INCLUDE BPA TRANSMISSION CREDITS IN ITS INITIAL FILING?

A. Yes. The Company included transmission credits in April through December of the test period in its initial filing. Tucannon River was not assumed to have commenced operation in January through March of the test period, so transmission credits were excluded in those months of the initial filing.

Q. DID THE TRANSMISSION CREDITS INCLUDED IN THE APRIL 1, 2014 MONET UPDATE REFLECT THE COMPANY'S NEW ASSUMPTION THAT TUCANNON RIVER WOULD BE PLACED IN SERVICE PRIOR TO THE TEST PERIOD?

A. No. The Company still excluded transmission credits in January and February of the test period. It is not clear why these credits were assumed to begin when the plant commenced operation in the Company's initial filing, yet in its April 1, 2014 update, they were assumed to begin two months subsequent to the commencement of plant operation.

In response to ICNU Data Request 77, the Company indicated that this assumption was based on representations made by its assigned BPA account executive.[21/] The Company's response, however, did not identify any BPA business practice or other official documentation requiring that transmission credits not be paid for the first two months subsequent to when a resource commences operation. If the Company assumed in its initial filing that it would receive transmission credits beginning when Tucannon River is placed in service, it is unclear why this would not continue to be the case.

Q. WILL YOU PLEASE SUMMARIZE YOUR RECOMMENDATION?

A. The Company's initial filing assumed transmission credits began to accrue when the plant was placed in service. It has not provided adequate documentation to justify a change from that assumption. Given that the Company has not identified any official documentation to suggest that transmission credits do not accrue in the first two months of a resource's life, I recommend that transmission credits be included in January and February of the test period.

VI. START-UP AND SHUT-DOWN COSTS

Q. PEASE DESCRIBE THE CORRECTION REGARDING THE FIRST START-UP AND FINAL RAMP-DOWN OF THERMAL RESOURCES.

A. The dispatch logic in the MONET model assumes that every thermal facility is committed down in the hour immediately preceding the study period. This causes each plant to incur start-up related costs in the first hours of the study even though the plants may have been running prior to the study period. The model also assumes that plants

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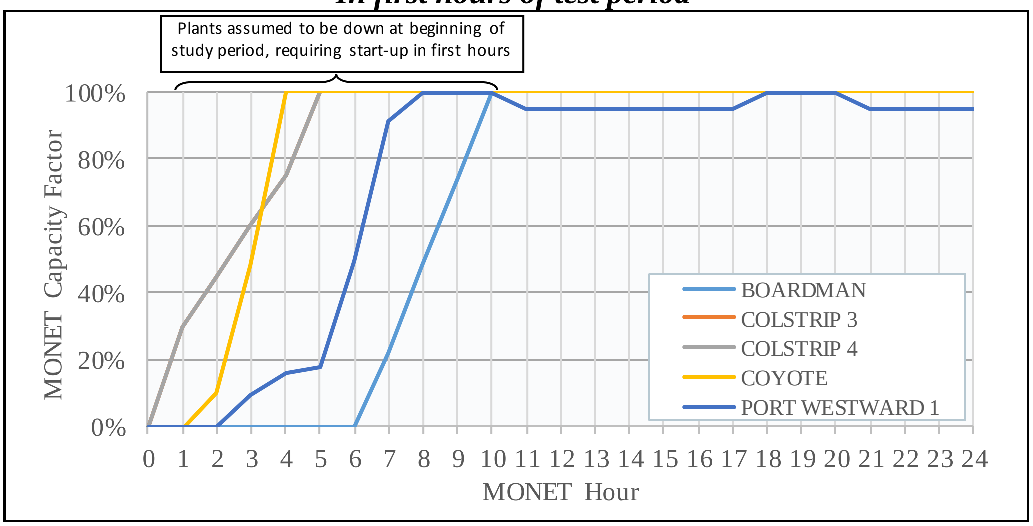
21/ See Exhibit ICNU/106

must be ramped-down at the end of the test period. I propose to correct this dispatch logic error, which reduces NVPC by $148,601.

Q. CAN YOU DEMONSTRATE THAT THE MODEL REQUIRES EACH PLANT TO START-UP AT THE BEGINNING OF THE STUDY PERIOD?

A. Yes. The following chart shows that each plant must go through a start-up routine at the beginning of the study period. The figure excludes Beaver and Port Westward II, which are not economic in the first hours of the study.

FIGURE 4
PLANT CAPACITY FACTORS
In first hours of test period



As can be seen in the chart, each plant is assumed to start-up, causing it to operate at low efficiency levels and preventing the model from using generation output to make economic sales into the market. I have removed the economic impact of this initial start in my adjustment by assuming that plants which are economic in the first hour of the study period were already running at full capacity immediately prior to the study period.

Q. DOES MONET ALSO REQUIRE SOME PLANTS TO RAMP DOWN IN THE FINAL HOURS OF THE STUDY PERIOD?

A. Yes. Several plants are also forced to ramp down in the final hours of the study, even though it likely would have been economic for them to keep running at full output beyond the study period. The cost of ramping-down resources in the final hours has also been included in this adjustment.

VII. MONTANA COLSTRIP EXCESS POWER WHEELING COST

Q. PLEASE DESCRIBE THE CORRECTION REGARDING MONTANA COLSTRIP EXCESS POWER WHEELING COSTS.

A. When output from Colstrip exceeds the Company's firm transmission rights on the Montana Intertie, the Company must purchase non-firm transmission to deliver Colstrip power to loads. The amount included in MONET, however, does not reflect amounts historically paid for non-firm transmission on the Montana Intertie. I propose an adjustment to better reflect historical non-firm transmission purchases, resulting in a reduction of $381,799 to NVPC.

Q. HOW MUCH NON-FIRM TRANSMISSION HAS THE COMPANY HISTORICALLY USED TO WHEEL POWER FROM COLSTRIP?

A. Between 2009 and 2013, the Company purchased, on average, [redacted] MW of hourly non-firm transmission per year. In contrast, the Company's filing assumes that it will purchase [redacted] MW of hourly non-firm transmission in the test period, an amount 3.5 times greater than the amount used historically.

Q HOW DID THE COMPANY CALCULATE NON-FIRM TRANSMISSION COSTS ON THE MONTANA INTERTIE?

A. The Company calculated the amount that the capacity of Colstrip Units 3 and 4 exceeded its firm Montana Intertie transmission rights and assumed that it was necessary to acquire that amount of non-firm transmission in every hour of the year.

Q. WHAT IS WRONG WITH THE COMPANY'S CALCULATION?

A. In practice, the Company only schedules non-firm transmission in the hours that it is needed, not in every hour of the year. If Colstrip dispatch falls below its firm transmission rights, it is not necessary to purchase additional non-firm transmission on the Montana Intertie. In 2013, for example, the Company only purchased non-firm transmission in [redacted] percent of the hours in the year, averaging to only [redacted] aMW of non-firm transmission. In its filing, however, the Company assumes that it will purchase non-firm transmission in 100 percent of the hours in the year, averaging to [redacted] aMW of non-firm transmission.

Q. HOW HAVE YOU CALCULATED THE IMPACT OF THIS CORRECTION?

A. I calculated the adjustment based on the average historical hourly non-firm transmission purchases made between 2009 and 2013 using current hourly non-firm transmission rates from the Company's transmission service provider. The result is a $381,799 reduction to NVPC.

VIII. MONTANA BENEFICIAL USE TAX

Q. WHAT IS THE CORRECTION THAT YOU ARE PROPOSING RELATED TO MONTANA BENEFICIAL USE TAXES?

A. The Company currently forecasts approximately $[redacted] of Montana beneficial use taxes in the test period. In 2013, however, the Company incurred only $[redacted] in Montana beneficial use taxes. Because of the material difference between these two, I propose to use the 2013 value in NVPC in this proceeding, rather than the Company's forecast. This will result in a $902,545 reduction to NVPC.

Q. PLEASE PROVIDE SOME BACKGROUND ON MONTANA BENEFICIAL USE TAXES.

A. Montana imposes a general beneficial use tax on private users of tax-exempt property located within the state, including the use of transmission lines rated greater than 500 kilovolts. As a result, the Company must pay beneficial use taxes in Montana for wheeling rights that it maintains on BPA's portion of the Montana Intertie. The tax, which is similar to a property tax, is assessed based on the value of the underlying transmission assets owned by BPA.

Q. WHY DO YOU BELIEVE THAT THIS CORRECTION IS APPROPRIATE?

A. Because beneficial use taxes are assessed much like a property tax, I would not expect them to change significantly from year to year. Yet, in the Company's filing, beneficial use taxes are forecast to be 4.4 times greater than what they were in 2013. The Company's filing does not provide documentation to support a known and measurable adjustment change from historical levels; therefore, the historical levels should be used in the filing.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 286

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Net Variable Power Costs (NVPC) and Annual	)
Power Cost Update (APCU)	)
	)

EXHIBIT ICNU/101

QUALIFICATIONS OF BRADLEY G. MULLINS

May 27, 2014

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Bradley G. Mullins. My business address is 333 S.W. Taylor Street, Suite 400, Portland, OR 97204.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am an independent consultant representing industrial customers throughout the western United States.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and in Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked at Deloitte Tax, LLP, where I was a Tax Senior providing tax consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters primarily involving power supply costs. I began performing independent consulting services in September 2013 and have been engaged with industrial organizations located throughout the western United States, including regulatory proceedings in Oregon, Washington and Wyoming. In Oregon, I am engaged to testify on behalf of ICNU before the Oregon Public Utility Commission in ongoing rate proceedings with Portland General Electric and PacifiCorp. In Washington, I am engaged to testify on behalf of ICNU before the Washington Utilities and Transportation Commission in the general rate proceeding of Avista. In Wyoming, I am engaged to provide non-testifying services related to various matters before the Wyoming Public Service Commission.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 286

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU)	)
	)

REDACTED EXHIBIT ICNU/102

PGE'S MARCH 18, 2014 BPA VERBS ELECTION WORKSHOP PRESENTATION

May 27, 2014

Exhibit ICNU/102 is confidential pursuant to Protective Order No. 14-043 and has been redacted in its entirety.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 286

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Net Variable Power Costs (NVPC) and Annual	)
Power Cost Update (APCU)	)
	)

REDACTED EXHIBIT ICNU/103

CALCULATION OF SELF-INTEGRATION BENEFITS

May 27, 2014

Exhibit ICNU/103 is confidential pursuant to Protective Order No. 14-043 and has been redacted in its entirety.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 286

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU)	)
	)
	)

REDACTED EXHIBIT ICNU/104

PGE RESPONSE TO ICNU DATA REQUEST NO. 026, INCLUDING SELECTION FROM ATTACHMENT A

May 27, 2014

April 7, 2014

TO: Bradley Van Cleve
Irion Sanger
Bradley Mullins

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 286
PGE Response to ICNU Data Request No. 026
Dated March 24, 2014

Request:

Please provide the wind study used to determine the expected capacity factor of the Tucannon wind resource in the request for proposal where that resource was selected. Please also provide any subsequent studies the Company has performed to estimate the expected capacity factor of the Tucannon resource.

Response:

The Tucannon bid was submitted with a wind energy study performed by RES Americas. The Independent Evaluator (IE) for PGE's renewable resource Request for Proposals (RFP) requested that an independent consultant, DNV-KEMA, review all wind energy studies submitted with each bid and make adjustments to the energy estimates for various factors in order to provide a standard basis for evaluating each bid.

Both the RES Americas wind energy study and the consultant's report were provided in "Vol 9 - Enhancements and New Items\Step 0n - Tucannon 100% Apr-Dec\Energy" of PGE Exhibit 500 confidential work papers filed on February 13, 2014, in Docket No. UE 283.

The Tucannon bid was submitted with different technology options and an expected site layout. In order to evaluate the technology options and changes to the site layout, PGE commissioned an ongoing independent wind study. As the Tucannon project has developed, the wind study has been revised to reflect changes that have occurred, such as turbine locations. Attachment 026-A provides a copy of the independent wind study and the subsequent revisions. Page 2 of “Revision D” details the difference between each revision of the study.

As stated in PGE Exhibit 500 in Docket No. UE 283 filed on February 13, 2014, PGE used DNV KEMA’s adjusted energy estimate, which was the basis for evaluating the wind bids in PGE’s renewable RFP. The independent study commissioned by PGE will be updated once all of the turbine foundations for Tucannon have been poured. Once the final revision of the study is available, PGE will update the expected Tucannon energy output estimate to the latest revision of the independent study in its next available power cost update filing.

Attachment 026-A is confidential and subject to Protective Order No. 14-043.

Pages 3 – 16 of Exhibit ICNU/104 are confidential pursuant to Protective Order No. 14-043 and have been redacted in their entirety.

DNV KEMA ENERGY & SUSTAINABILITY

DRAFT
Review of Wind Resource and Energy Assessments to Support PGE's Renewable RFP

CONFIDENTIAL

Portland General Electric Company
121 SW Salmon St
Portland, Oregon 97204

DNV KEMA Report No.: EARP0217
February 7, 2013

May 16, 2014

TO: Bradley Van Cleve
Tyler C. Pepple
Bradley Mullins

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 286
PGE Response to ICNU Data Request No. 077
Dated May 12, 2014

Request:

Referring to "#M610-PUC10-056-2015 GRC.xlsm", worksheet "PC Input", rows "1398" and "1393", PGE models the Tucannon Point-to-Point (PTP) transmission credits beginning in March 2015 while BPA PTP service costs for Tucannon begin in January 2015. Please provide the basis for modeling the Tucannon PTP transmission credits beginning in March, including the BPA business practices or other documentation that supports PGE's assumption.

Response:

The basis for modeling the Tucannon PTP transmission credits beginning in March has been based on discussions between PGE and its assigned Account Executive from BPA. A BPA business practice or other documentation is not available to PGE at this time.

PGE will update the Tucannon PTP transmission credits in subsequent power cost filings if the additional information revises PGE's forecast for schedule and/or quantity.