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May 28, 2015

Via Electronic Filing and Federal Express

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

Re: PORTLAND GENERAL ELECTRIC
2015 General Rate Case
Docket No. UE 294

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the Redacted Opening Power Cost Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Pursuant to the protective order in this proceeding, the sealed confidential portions of ICNU's testimony and exhibits will follow to the Commission via Federal Express, and to the parties that have signed the protective order via First Class U.S. Mail.

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

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential portions of the **Opening Power Cost Testimony and Exhibits of ICNU** upon the parties shown below by sending copies via First Class U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 28th day of May, 2015.

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY,	)
	)
Request for a General Rate Revision.	)
	)
	)

REDACTED OPENING POWER COST TESTIMONY

OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

May 28, 2015

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REDACTED OPENING POWER COST TESTIMONY
OF BRADLEY G. MULLINS**

EXHIBIT LIST

Exhibit ICNU/101—Qualification Statement of Bradley G. Mullins

Confidential Exhibit ICNU/102—Company Power Transactions by Market Hub

Confidential Exhibit ICNU/103—Responses to ICNU Data Requests

I. INTRODUCTION

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"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including customers of Portland General Electric Company ("PGE" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the Company's net variable power costs ("NVPC") and Annual Power Cost Update ("APCU") filing for 2016, which, pursuant to the Prehearing Conference Memorandum issued on March 6, 2015, is being processed on a separate procedural schedule from the main portion of this 2016 General Rate Case.[1/] Specifically, my testimony discusses the Company's $555.9 million net variable power cost forecast developed using the Multi-area Optimization Network Energy Transaction ("MONET") model,[2/] including specific adjustments and corrections to the Company's MONET modeling. In addition to this testimony, I will also be filing testimony on other rate case issues in the general rate case portion of this proceeding.

1/ Prehearing Conference Memorandum at 2 (Mar. 6, 2015).
2/ PGE/400 at 12-15.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony is summarized and organized as follows:

1. **California-Oregon Border Margins.** The Company realizes significant economic benefits as a result of its transmission access to the California-Oregon Border ("COB") market. These benefits, however, are not currently reflected in the MONET model, which inaccurately assumes all transactions occur at the Mid-Columbia ("Mid-C") market. I recommend an adjustment to properly account for transactions at COB that will reduce the Company's net variable power costs forecast by approximately $[redacted].

2. **Load Net of Wind Reserves.** The MONET model contains an error in how it combines load- and wind-following reserve requirements. The Company incorrectly used the arithmetic sum, rather than the root-sum-of-squares formula, to perform this calculation. Correcting this error will reduce net variable power costs by $0.7 million.

3. **Super Peak Purchase.** The MONET model includes a hypothetical [redacted] MW super peak purchase contract, which is not known and measurable and no longer necessary given the addition of new capacity resources. Removing this contract will reduce net variable power costs by approximately $0.4 million.

4. **Pipeline Capacity Release Credits.** Over the period 2011 through 2014, the Company generated revenue through the resale of pipeline capacity and the receipt of capacity release credits. The MONET model, however, does not include any pipeline capacity release credits in the test period. I propose an adjustment to account for potential pipeline capacity release revenues in the test period, which will reduce net variable power cost by $[redacted].

Q. HAVE YOU PREPARED A SUMMARY TABLE TO DETAIL THE IMPACT OF EACH OF THESE RECOMMENDATIONS?

A. Confidential Table 1, below, details the impact of each of these recommendations relative to the net variable power costs in the Company's initial filing, including an adjustment to reflect the impact of the Company's April update.

CONFIDENTIAL TABLE 1
Summary of Recommended Net Variable Power Cost Adjustments
($000)

		ln
Initial Filing (Feb 12)	**555,914**	1
Adjustments & Updates:		
1. California-Oregon Border Margins	[redacted]	2
2. Load Net of Wind Reserves	(661)	3
3. Super Peak Purchase	(407)	4
4. Pipeline Capacity Release Credits	[redacted]	5
5. Company's April Update	*(5,608)*	6
Total	[redacted]	7
Recommended	[redacted]	8

Q. TO THE EXTENT YOUR OPENING POWER COST TESTIMONY DOES NOT ADDRESS A PARTICULAR ISSUE, SHOULD THAT BE INTERPRETED AS YOUR ACCEPTANCE OF THAT ISSUE?

A. No.

II. CALIFORNIA-OREGON BORDER MARGINS

Q. WHAT IS YOUR RECOMMENDATION RELATED TO ECONOMIC MARGINS REALIZED AT COB?

A. The MONET model calculates system dispatch based on a single market hub—the Mid-C market. In actual operations, however, the Company participates in several different markets, with COB being the predominant market other than Mid-C where the Company makes market transactions. Through its ability to transact at both Mid-C and COB, the Company realizes substantial economic benefits, which are derived from monetizing the spreads between Mid-C and COB prices. Customer base rates currently include the cost of the transmission assets on the California-Oregon Intertie ("COI") that facilitate these economic transactions at the COB market, and it follows that customers should also recognize the incremental economic benefits, not currently reflected in the MONET model, associated with the Company's trading activities at this market. Based on the actual economic margins earned by the Company between 2012 and 2014, I recommend a $[redacted] adjustment to net variable power costs to reflect these incremental economic benefits derived from the COB market.

Q. HOW ARE MARKET SALES AND PURCHASES MODELED IN MONET?

A. The mechanics of the MONET model were described by the Company in PGE/400 at 5:1-10. As discussed in that testimony, the MONET model calculates economic dispatch based on a comparison of the hourly dispatch cost of each resource to a single electric market price,[3/] which is the Mid-C market. After dispatch has been determined, the MONET model will balance the Company's overall load and resource position by making sales in hours when the amount of dispatched resources is greater than the Company's loads and by making purchases in hours when the amount of dispatched resources is less than the Company's load.[4/] All of these market sales and purchases are assumed to occur at the Mid-C market, and in no hour will the MONET model make purchases or sales at the COB market, even though it is common for the Company to make such purchases and sales at COB in actual operations. This is in contrast to other power cost models, such as PacifiCorp's GRID model, that forecast economic dispatch based on multiple markets and based on a transmission constrained network topology.

Q. WHAT ARE THE OTHER MARKETS WHERE THE COMPANY MAKES POWER TRANSACTIONS?

A. In contrast to MONET's assumptions, in actual operations, the Company is capable of making power transactions at several different markets, which result in lower overall dispatch costs

3/ Id. at 5:2-5.
4/ Id. at 5:5-10.

compared to those calculated in the MONET model. Confidential Exhibit ICNU/102 details the quantity and volume of power transactions made by the Company by market in calendar years 2012, 2013 and 2014. A summarized version of this analysis is presented in Confidential Table 2, below.

CONFIDENTIAL TABLE 2

Company Transactions by Market Hub

[redacted]

As noted from Confidential Table 2, Mid-C was the predominant market where the Company entered into power transactions between 2012 and 2014. However, the Company also made material amounts of transactions at power markets other than Mid-C over the period. Sales transactions at the COB market, for example, constituted approximately [redacted]% of all sales transactions made by the Company over the period and approximately [redacted]% of total sales volumes. For purposes of this analysis, as well as the following analyses, transactions at the Nevada-Oregon Border were included in the definition of the COB market. In addition, the

Company has also been making an increasing number of sales transactions at other extra-regional markets, such as Palo Verde, Mona, Mead and Four Corners. While my recommendation does not address the economics of these extra-regional markets, the Company, through its participation in these markets, is likely earning additional economic benefits that are not reflected in the MONET model nor in my proposed adjustment.

Q. HOW MUCH POWER CAN THE COMPANY BUY AND SELL AT THE COB MARKET?

A. The Company's merchant function currently has approximately 296 MW of north-to-south transmission rights on the COI,[5/] enabling it to sell up to 296 MWh of energy at the COB market in any hour of the year. In addition, the Company has approximately 450 MW of south-to-north transmission rights on the COI,[6/] enabling it to purchase up to 450 MWh of energy at the COB market in any hour of the year. The ultimate amount that the Company can transmit on the COI, however, is at times limited by the Bonneville Power Administration, which, as the path operator, will derate the total transmission capacity available on the COI for reliability purposes.

Q. DO CUSTOMERS PAY FOR THESE MERCHANT TRANSMISSION RIGHTS TO THE COB MARKET?

A. Yes. Customers currently pay in base rates for the revenue requirement associated with all of the Company's owned transmission assets on the COI that provide access to the COB market. The Company is an owner of approximately 950 MW of bi-directional transmission assets on the COI. It invested in these assets as a participant in the Pacific AC Intertie project, a regional effort in the late 1960s to integrate the power systems in the Northwest with increasing loads in

[5/] See Confidential ICNU/103 (the Company's Response to ICNU Data Request ("DR") No. 85).
[6/] Id.

Northern and Southern California.[7/] While the assets are included in rate base, a portion of the revenue requirement of these legacy assets is offset by Open Access Transmission Tariff ("OATT") wheeling revenues, as the majority of the Company's COI transmission capability is currently resold to third parties. The total amount that customers pay, therefore, is the net amount of revenue requirement associated with these assets, an amount that is representative of the cost of rights reserved by the Company's merchant function detailed above.

Q. IS IT FAIR TO REQUIRE CUSTOMERS TO PAY FOR TRANSMISSION TO COB, WITHOUT RECEIVING THE CORRESPONDING BENEFITS OF THAT MARKET?

A. No. Customers are currently paying the cost associated with transmission access to the COB market; therefore, it does not appropriately match costs and benefits to require customers to forgo the economic benefits derived by the Company as a result of its ability to make transactions at the COB market.

Q. HOW DOES THE COMPANY REALIZE ECONOMIC BENEFITS AS A RESULT OF ITS ACCESS TO THE COB MARKET?

A. With its transmission access to the COB market, the Company is capable of earning a margin on the differences between Mid-C and COB market prices. In hours when COB market prices are greater than Mid-C market prices, the Company can purchase from the Mid-C market and sell into the COB market, earning an economic margin on the difference between the two prices. In hours when COB market prices are less than Mid-C market prices, the Company can purchase from the COB market and sell into the Mid-C market, also earning economic margins on the difference between the two prices.

[7/] See Gene Tollefson, BPA & The Struggle for Power at Cost, 336-338 (1987).

Q. HOW MUCH ECONOMIC BENEFIT HAS THE COMPANY HISTORICALLY REALIZED AS A RESULT OF ITS ACCESS TO THE COB MARKET?

A. As an owner of both south- and north-bound transmission rights on the COI, the Company has realized substantial economic benefits by being able to make sales and purchases at both the Mid-C and COB markets. Based on my review of actual transactions the Company has executed at the COB market, these economic benefits have ranged from $[redacted] to $[redacted] per year over the period 2012 through 2014. Confidential Table 3, below, details the results of my analysis and the actual benefits that the Company has realized associated with its access to the COB market.

CONFIDENTIAL TABLE 3

<u>Historical Margins on COB Sales and Purchases</u>

[redacted]

Q. PLEASE PROVIDE AN OVERVIEW OF HOW THE FIGURES IN CONFIDENTIAL TABLE 3 WERE CALCULATED.

A. The figures in the above table were calculated based on the actual power transactions, both sales and purchases, made by the Company at the COB market in calendar years 2012 through 2014. The calculations were performed using trade data provided in response to ICNU DR Nos. 84 and 91.[8/] For each transaction that the Company made at the COB market, I compared the transaction price to the actual hourly Mid-C market price to determine the economic margin actually earned on each COB transaction. I then aggregated the economic margins associated with each transaction by year, separately for sales and purchases, to develop the annual economic benefit associated with the Company's participation at the COB market, presented in Confidential Table 3, above.

Q. HOW DO THESE BENEFITS CORRESPOND TO THE AMOUNT OF BENEFITS EXPECTED IN THE TEST PERIOD?

A. The historical economic benefits derived from COB market transactions, relative to the Mid-C market, are a fair estimate of the level of economic benefits attributable to COB market activity expected in the test period. Because these economic benefits are driven by the difference in market prices between the two markets, rather than the overall level of market prices, the Company will be able to derive economic benefits from the spreads between the two markets, regardless of market conditions. For example, the historical relationship between the two markets—where COB market prices have typically exceeded Mid-C market prices by several dollars—could reverse in its entirety, and the Company would still have an opportunity to recognize a similar amount of economic benefit by predominantly making purchases, rather than sales, at the COB market. Notwithstanding, there is no indication that the economic

8/ See Confidential ICNU/103.

factors underlying the market spreads between the Mid-C and COB markets, such as the load and resource characteristics of southern California, will change materially in the test period, so the historical spreads between the two markets, and underlying economic benefits detailed above, are not expected to change materially in the test period.

Q. HOW DO YOU PROPOSE TO REFLECT THE BENEFITS OF THE COB MARKET IN THE NET VARIABLE POWER COST FORECAST?

A. Because the historical benefits detailed above are a fair representation of the economic benefits expected in the test period, my proposal is to use the average actual economic benefits associated with the Company's trading activities at the COB market, as detailed in Confidential Figure 3, as an adjustment to net variable power costs in this proceeding.

Q. IS THIS ISSUE A FACTOR THAT HAS LED TO THE COMPANY OVER-FORECASTING POWER COSTS IN RECENT YEARS?

A. In 3 of the last 4 years, the Company has over-forecast its power costs in amounts ranging from $12.3 million to $34.2 million, detailed in Table 4 below.

TABLE 4
Power Cost Variance in PCAM
Over / (Under) Collection ($000)

2010	2011	2012	2013
12,353	34,256	16,929	(11,015)

As noted, the only recent year when the Company did not over-forecast power costs was 2013, and the Company's under-collection in that year was likely driven by the major six-month outage that occurred at Colstrip Unit 4.[9/] While there are many factors that lead to over- and under-forecasting of net variable power costs, the lack of consideration for the transactions

9/ See Docket No. UE 283, PGE/800 at 11:7-12:14 for a discussion of the Colstrip Unit 4 outage.

at COB and other extra-regional markets in the MONET model may be one factor that has led to this pattern of over-forecasting.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Because the MONET model does not account for transactions at the COB market, the Company's net variable power costs forecast is currently overstated. As demonstrated in Confidential Table 3, these transactions produce material economic benefits and should be reflected in the Company's net variable power cost forecasts. Customers already pay for the cost of transmission to the COB market and should also receive the corresponding benefits associated with the Company's trading activities at the COB market. Based on the analysis of the actual economic benefits associated with COB transactions presented above, I recommend an adjustment of approximately $[redacted] to properly account for these benefits.

III. LOAD NET OF WIND RESERVES

Q. WHAT CORRECTION ARE YOU PROPOSING RELATED TO THE COMPANY'S CALCULATION OF LOAD- AND WIND-FOLLOWING RESERVES?

A. The Company uses incorrect mathematics to combine the reserve requirements associated with load and wind. These reserve requirements must be combined using a root-sum-of-squares ("RSS") formula, rather than the arithmetic sum used by the Company. This RSS formula is the standard industry practice for combining load and wind errors for purposes of estimating reserve requirements and wind integration costs. The impact of this correction is a $660,900 reduction to net variable power costs.

Q. PLEASE DESCRIBE HOW THE COMPANY MODELED FOLLOWING RESERVES.

A. The Company filing includes new logic in the MONET model to account for hourly following reserves for both load and wind resources. These following reserves represent the capacity that must be withheld in order to assure that the Company will be capable of responding to changes in load and wind over the course of an hour. They are in addition to regulation reserves, which represent the reserves that must be held in order to maintain system frequency. For purposes of the MONET model, the reserve requirements for both load and wind were calculated independently, based on a distribution of historical forecast errors. For load, the average amount of following reserve requirement was calculated to be [redacted] aMW.[10/] For wind, the average amount of following reserve requirement was calculated to be [redacted] aMW.[11/] The Company combined these two load and wind following reserve requirements using an arithmetic sum to arrive at a total system following reserve amount of [redacted] aMW.

Q. WHY IS IT INCORRECT TO USE THE ARITHMETIC SUM?

A. Because load and wind forecast errors do not correlate to each other, they may cancel out in some hours, meaning the combined variability of these two independent factors is less than the sum of their parts. The reason why it is inappropriate to evaluate these two factors in isolation was described in a report by the National Renewable Energy Laboratory ("NREL") describing the use of an arithmetic sum as common error in integration analyses:

> Double counting in one form or another is probably the most common error made in integration studies. This usually results from failing to account for aggregation benefits, either among wind facilities and/or between wind and load. … Load and wind forecast errors typically do not add linearly and consequently benefit from aggregation. The sum of the forecast error reserves allocated to wind and load should not exceed the total system forecast error reserves[12/]

[10/] These reserve values can be found in the Company's Minimum Filing Requirements at ToPUC\ #M610PUC10-00h-2016 GRC.xlsm (the MONET model file), tab "AS Wind." They represent the average hourly following reserve amounts in Excel columns "J" and "L" for load and wind, respectively

[11/] Id.

[12/] Michael Milligan, et al., Cost-Causation and Integration Cost Analysis for Variable Generation at 24-25 (June 2011), available at http://www.nrel.gov/docs/fy11osti/51860.pdf.

Q. IS IT STANDARD INDUSTRY PRACTICE TO USE THE RSS FORMULA TO COMBINE LOAD AND WIND VARIABILITY?

A. Yes. It is generally accepted that reserve measurements based on load and wind forecast errors should be combined using the RSS formula to arrive at a reserve value that is representative of the load-net-wind forecast errors. PacifiCorp's 2014 Wind Integration Study, for instance, discussed this concept in detail.[13/] PacifiCorp noted that because the reserve components are representative of different deviations between actual and forecast values, "they are not additive," and that "the wind and load reserve requirements are combined using the root-sum-of-squares (RSS) calculation in each direction (up and down)."[14/] BC Hydro also recently discussed the use of the RSS formula to combine load and wind reserve requirements, noting that "[t]he reserves for load-net-wind are determined by combining the load only and wind only reserves using the root-sum-squares method."[15/]

Q. WHAT IS THE RSS FORMULA?

A. The RSS formula is the same that is used for combining the standard deviation of two uncorrelated distributions: $\sqrt{L^2 + W^2}$, where L equals the load following reserve measurement and W equals the wind-following reserve measurement.

Q. HOW DOES THIS FORMULA IMPACT THE LOAD- AND WIND-FOLLOWING RESERVES IN THE MONET MODEL?

A. Applying this formula to the hourly load- and wind-following reserve amounts included in the MONET model results in a load-net-of-wind following reserve amount of approximately [redacted] aMW. This is a [redacted] aMW reserve reduction from the amount assumed in MONET in the Company's initial filing, which reduces net variable power costs by $660,900.

13/ PacifiCorp 2015 Integrated Resource Plan ("IRP"), Volume II, App. H, at 119.

14 Id.

15/ BC Hydro, 2013 Integrated Resource Plan, Appendix 3E-Wind Integration Study Phase II at 3E-9 (Nov. 2013).

IV. SUPER PEAK PURCHASE

Q. PLEASE PROVIDE AN OVERVIEW OF THE HYPOTHETICAL SUPER PEAK PURCHASE CONTRACT ASSUMED IN MONET.

A. The Company currently assumes that it will execute a [redacted] MW hypothetical super peak purchase in the test period. This is not an actual contract that the Company has executed but is, instead, merely assumed by the Company [redacted].[16] I disagree with the inclusion of this contract in MONET, as it is 1) not known and measurable; 2) not needed, as the Company will have 660 MW of new capacity in the test period through Port Westward II and the Carty Generating Station; and 3) is based on a flawed pricing methodology. Removing this contract will reduce net variable power costs by $407,400.

Q. PLEASE DESCRIBE THE HYPOTHETICAL SUPER PEAK PURCHASE.

A. The super peak purchase is a hypothetical transaction for a [redacted] MW block of power in super peak hours—hours ending 13 through 20, Monday through Saturday, excluding NERC Holidays—for the months of August and September. The price of the assumed contract is [redacted]% of the monthly Heavy Load Hour ("HLH") Mid-C price in those months.

Q. IS THIS SUPER PEAK CONTRACT KNOWN AND MEASURABLE?

A. No. No actual [redacted] MW super peak contract has been executed by the Company, and it is not known whether the Company will make such a purchase in 2016. To the extent that the Company does purchase a super peak contract, neither the ultimate MW amount nor purchase price, relative to the Company's forward price curve, is known at this time.

[16] See Minimum Filing Requirements, Vol 5 - Electric and Gas Contracts\Super-Peak Purchase\#_2016GRCSuperPeak.docx.

Q. IS THERE REASON TO EXPECT THAT A SUPER PEAK CONTRACT WILL NOT BE NEEDED IN THE TEST PERIOD?

A. Yes. The Company recently added approximately 220 MW of new capacity through the addition of Port Westward II in December 2014. In addition, by the time of the 2016 summer peak, the Carty Generating Station will be online, adding an additional 440 MW to the Company's resource portfolio.[17/] This collective 660 MW of capacity will mitigate the need for any super peak purchases in August and September of 2016.

Q. DOES THIS NEW CAPACITY MAKE THE COMPANY'S [redacted]

A. Yes. This 660 MW of new capacity makes the Company's basis for this hypothetical super peak contract no longer accurate because [redacted]

Q. HOW DID THE COMPANY CALCULATE THE PRICE FOR THE ASSUMED SUPER PEAK CONTRACT?

A. The Company assumed that the super peak contract will be at a price that is [redacted]% of the HLH Mid-C price in August and September of 2016. This assumption was based on an analysis of the historical relationship between the HLH Mid-C prices included in the final MONET update in November and the price of actual super peak products purchased by the Company subsequent to the update and based on a subsequent price forecast.

Q. DOES THE MONET MODEL ALREADY REFLECT SUPER PEAK PURCHASES IN ITS DISPATCH?

A. Yes. When the MONET model performs dispatch it will make the purchases necessary in super peak hours to satisfy loads. The price for these model purchases are based on the super peak prices included in the Company's forward price curve, not the pricing included in the

17/ PGE/300 at 14:2 (noting guaranteed online date for Carty of May 16, 2016).

Company's assumed super peak contract. Thus, the MONET model already accounts for the cost of making additional super peak purchases in the test period.

Q. HOW DOES THE COMPANY'S PRICE CALCULATION FOR ITS HYPOTHETICAL SUPER PEAK CONTRACT COMPARE WITH SUPER PEAK PRICES ALREADY ASSUMED IN MONET?

A. The super peak prices included in the Company's forward price curve in MONET are only approximately [redacted]% and [redacted]% higher than the HLH Mid-C price in the months of August 2016 and September 2016, respectively. Thus, even if it were appropriate to include a hypothetical super peak contract, the Company's assumption that this super peak contract will be at a price that is [redacted]% of HLH Mid-C prices is inconsistent with the price curve that the Company has prepared for this proceeding.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT RELATED TO THE HYPOTHETICAL SUPER PEAK CONTRACT.

A. I propose that the hypothetical [redacted] MW super peak contract modeled by the Company be excluded from net variable power cost in this proceeding. The contract does not rise to the level of being known and measurable, and, therefore, is not appropriate to be included in the test period. The need for super peaking capacity will be reduced in the test period as a result of the addition of new resources, such as Port Westward II and the Carty Generating Station. The MONET model also already includes the costs associated with acquiring super peaking capacity in its forward price curve, and it is not necessary for the Company to add additional costs into the model associated with meeting capacity needs in super peak hours. Removing this contract will reduce net variable power costs by $407,400.

V. PIPELINE CAPACITY RELEASE CREDITS

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RECOMMENDATION RELATED TO PIPELINE CAPACITY RELEASE CREDITS.

A. The Company has historically earned material amounts of revenue associated with pipeline capacity release credits.[18/] The Company, however, has not assumed that it will recognize any revenues associated with these capacity release transactions in the test period. While the Company's pipeline capacity needs are likely changing as a result of the additions of Port Westward II and the Carty Generating Station, the Company should, due in part to the flexibility associated with its storage contracts, be able to recognize some degree of capacity release revenue in the test period. My recommendation is to reflect capacity release revenues in the net variable power cost forecast based on a four-year rolling average, which, in this proceeding, will reduce the Company's forecast by $[redacted].

Q. WHAT ARE PIPELINE CAPACITY RELEASE CREDITS?

A. A pipeline capacity release is the process of re-selling all or any portion of firm pipeline capacity. Modern capacity release markets were originally developed through Federal Energy Regulatory Commission ("FERC") Order No. 637, which required pipelines to openly post the capacity that their service requesters sought to release on an electronic bulletin board with standardized data elements.[19/] According to FERC, these federally regulated capacity release markets "improve the efficiency of the market and provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity."[20/]

18/ Confidential Exhibit ICNU/103 (The Company's Response to ICNU DR 90, Confidential Attachment A)

19/ In re Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services, FERC, Docket Nos. RM98-10-000 & RM98-12-000, Order No. 637 at 206-207 (Feb 9, 2000).

20/ Id. at 1

Q. HOW MUCH REVENUE DID THE COMPANY RECOGNIZE IN RELATION TO CAPACITY RELEASE CREDITS BETWEEN 2011 AND 2014?

A. On average, the Company recognized [redacted] per year in long-term pipeline capacity releases in each year 2011 to 2014.[21/] In addition, the Company recognized an additional [redacted] and [redacted] in short-term capacity release revenues in 2011 and 2012, respectively.[22/] Including both long-term and short-term pipeline capacity release credits, the Company recognized, on average, $[redacted] in capacity release revenues on an annual basis over the four year period 2011 to 2014.

Q. WHAT PIPELINE RIGHTS IS THE COMPANY CAPABLE OF RELEASING?

A. The Company is a shipper on several different interstate pipelines that would allow it to release its pipeline capacity in periods when little or no capacity is needed. For example, the facilities located near Clatskanie, Oregon—Port Westward, Port Westward II, and Beaver—are all primarily served off of the [redacted].[23/] The Company's other gas plants, such as Coyote Springs and the Carty Generating Station, [redacted].[24/] My understanding is that all of these pipelines, [redacted], offer the opportunity to resell capacity in periods when it is not needed by the shipper.

21/ Confidential Exhibit ICNU/103 (The Company's Response to ICNU DR 90, Confidential Attachment A).

22/ Id.

23/ See the Company's Minimum Filing Requirements at \Vol 5 - Electric and Gas Contracts\Gas Transportation\Beaver-Port Westward\.

24/ See the Company's Minimum Filing Requirements at Vol 5 - Electric and Gas Contracts\Gas Transportation\Coyote Springs\ and \Vol 9 - Enhancements and New Items\Step 0h - Carty\Fuel Cost\Fixed\

Q. WILL THE COMPANY BE CAPABLE OF RECOGNIZING PIPELINE CAPACITY RELEASE REVENUES IN THE TEST PERIOD?

A. Yes. Much of the historical revenues recognized over the period 2011 to 2014 were derived from a single long-term capacity release contract. While it was not clear from the Company's response to ICNU DR 90 whether that contract will continue be in place in the test period,[25/] the Company should have a similar opportunity to pursue capacity release revenues in the test period to those that were available in prior years. The Company has acquired new pipeline capacity in connection with the construction of Port Westward II and the Carty Generating Station, which will result in additional capacity that may be released and new opportunities to earn revenues in the test period.

Q. DO THE COMPANY'S STORAGE CONTRACTS INCREASE ITS ABILITY TO GENERATE REVENUE THROUGH CAPACITY RELEASES?

A. Yes. In particular, the gas storage capacity associated with the construction of Port Westward II, in addition to that available for Port Westward and Beaver, may provide the Company with a number of opportunities to release pipeline capacity on [redacted] in months when there is little demand from the peaking resources located at Clatskanie. In periods when little gas is being withdrawn from its storage facilities to service the Clatskanie resources, the Company could earn revenue by releasing a portion of its interstate pipeline capacity and relying more heavily on storage for purposes of meeting the reduced gas requirements of those resources.

Q. HOW DO YOU PROPOSE TO INCLUDE CAPACITY RELEASE REVENUES IN THE TEST PERIOD?

A. Because the ultimate amount of capacity release credits may vary year to year depending on market conditions, I recommend including a four-year rolling average of pipeline capacity

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25/ See Confidential ICNU/103.

release revenues in net variable power costs. In addition to providing ratepayers the benefit of these revenues, such a methodology will encourage the Company to efficiently manage its firm pipeline transportation rights. Based on this methodology, my recommendation is to include $[redacted] of revenue in the Company's net variable power cost forecast to account for both short-term and long-term capacity release revenues expected in the test period.

Q. DOES THIS CONCLUDE YOUR OPENING POWER COST TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY,	)
	)
Request for a General Rate Revision.	)
	)
	)

EXHIBIT ICNU/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

May 28, 2015

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 as a Tax Senior at Deloitte Tax, LLP, where I provided tax compliance and 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. I currently provide consulting services for utility customers, independent power producers, and qualifying facilities on matters ranging from power costs and revenue requirement to power purchase agreement negotiations.

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

A. I have sponsored testimony in regulatory proceedings throughout the western United States, including the following:

- Or.PUC, UM 1662: In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation
- Or.PUC, UM 1712: In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction
- Bonneville Power Administration, BP-16: 2016 Joint Power and Transmission Rate Proceeding
- Wa.UTC, UE-141368: In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes

- Wa.UTC, UE-140762: In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million
- Wa.UTC, UE-141141: In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs
- Wy.PSC, 20000-446-ER-14: In re The Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent
- Wa.UTC, UE-140188: In re Avista Corporation, General Rate Increase For Electric Services, RE: Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015
- Or.PUC, UM 1689: In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market
- Or.PUC, UE 287: In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism.
- Or.PUC, UE 283: In re Portland General Electric Company, Request for a General Rate Revision
- Or.PUC, UE 286: In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU)
- Or.PUC, UE 281: In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment

- Or.PUC, UE 267: In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck).

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY,	)
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Request for a General Rate Revision.	)
	)
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REDACTED EXHIBIT ICNU/102

COMPANY POWER TRANSACTIONS BY MARKET HUB

May 28, 2015

Exhibit ICNU/102 is confidential pursuant to the protective order in this proceeding and has been redacted in its entirety.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY,	)
	)
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	)

REDACTED EXHIBIT ICNU/103

COMPANY RESPONSES TO ICNU DATA REQUESTS

May 28, 2015

May 8, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 084
Dated April 24, 2015

Topic or Keyword: Power Costs

Request:

Please provide an extract from the Company's energy trading information systems that details each and every power and gas transaction, including both physical and financial transactions, settled or delivered in the period January 2012 through March 2014. Please include each and every field stored in the energy trading system for each transaction and do not delete any columns or data from the extract.

Response:

Due to its voluminous and highly-sensitive nature, PGE has not posted the requested material to Huddle. Rather, PGE has provided only ICNU with electronic copies of PGE's extract from its energy trading information systems. To request a copy of the material provided to ICNU, please contact Karla Wenzel at (503) 464-8718.

See Attachment 084-A for power transactions settled or delivered in 2012.

See Attachment 084-B for power transactions settled or delivered in 2013.

See Attachment 084-C for power transactions settled or delivered from January 2014 to March 2014.

See Attachment 084-D for gas transactions settled or delivered from January 2012 through March 2014.

Attachments 084-A, 084-B, 084-C and 084-D are confidential and subject to Protective Order No. 15-036.

May 22, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 085
Dated May 8, 2015

Keyword: Power Costs

Request:

Please detail the total MW of north- and south-bound long-term transmission capability owned or purchased by the Company's merchant function on the California Oregon Intertie by reservation number.

Response:

PGE's Merchant Operations has purchased the following rights for south-to-north (i.e., north-bound) long-term firm transmission capability from PGE Transmission Services on the California Oregon Intertie.

Reservation #	MW Granted	Start Date	End Date
79875117	250	01/01/2015	01/01/2020
76412778	200	01/01/2012	01/01/2017
Total	**450**	**-**	**-**

PGE's Merchant Operations has purchased the following rights for north-to-south (i.e., south-bound) long-term firm transmission capability from PGE Transmission Services on the California Oregon Intertie.

Reservation #	MW Granted	Start Date	End Date
74382640	86	01/07/2012	01/07/2017
432190	100	01/01/2002	01/01/2022
74566698	100	01/01/2012	01/01/2022
79082732	10	01/01/2014	01/01/2034
Total	**296**	**-**	**-**

May 22, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 090
Dated May 8, 2015

Keyword: Power Costs

Request:

Please detail the total Dth amount of pipeline capacity released and capacity release credit revenue associated with all long-term and short-term capacity release arrangements in place over the period 2011 to 2014 (inclusive). At a minimum, please detail the capacity release credits by month and by replacement shipper.

Response:

Attachment 090-A provides PGE's short-term and long-term pipeline capacity release by month, including volume, rate, revenue, and replacement shipper.

Attachment 090-A is confidential and subject to Protective Order No. 15-036.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

May 27, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 091
Dated May 13, 2015

Keyword: Power Costs

Request:

Please update the response to ICNU Data Request 84, specifically Confidential Attachment 84-C, to provide trade data through December 2014, rather than March of 2014.

Response:

Note: Due to its voluminous and highly-sensitive nature, PGE has not posted the requested material to Huddle. Rather, PGE has provided only ICNU with electronic copies of PGE's extract from its energy trading information systems. To request a copy of the confidential material provided to ICNU, please contact Karla Wenzel at (503) 464-8718.

See Attachment 091-A for power transactions settled or delivered from January 2014 to December 2014. Attachment 091-A is confidential and subject to Protective Order No. 15-036.